

Use of Selective Catalytic Reduction For Control of NO_x Emissions From Power Plants in the U.S.



Three **Selective Catalytic Reduction** systems are installed at B.C. Hydro's Burrard Station, a natural gas-fired plant located near Vancouver.

Prepared for
The OntAIRio Campaign

Prepared by
Bruce Biewald, Joe Cavicchi, Tim Woolf and Daniel Allen
Synapse Energy Economics, Inc.

February, 2000

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1. Introduction & Summary

Selective catalytic reduction (SCR) technologies offer an economic and effective means of reducing nitrogen oxide (NO_x) emissions from electricity generation facilities. SCR is typically capable of removing 70 to 80 percent of NO_x emissions from fossil fuel power plants, and is widely considered the most effective technology demonstrated to date for this purpose.¹ Synapse Energy Economics, Inc. has been retained by the OntAIRio Campaign to assess the costs and feasibility of utilizing SCR technologies on electricity generation facilities in Ontario.

SCR processes reduce NO_x emissions by reacting ammonia with NO_x on the surface of a catalyst to selectively reduce the NO_x to nitrogen and water. The technology consists of an injection grid that admits ammonia into the exhaust gas of a power plant or boiler upstream of a catalyst that in combination with ammonia results in the reduction of NO_x from the exhaust gas. This process can be applied to exhaust gases ranging in temperature from 450-1100 degrees Fahrenheit (typical practice sees gases in the 525-750 degree range). The byproducts of the process are residual ammonia, resulting from “the imperfect mixing and reaction of reagent,” (OTAG) and SO₃, which is oxidized from SO₂ by the catalyst. The formation of both byproducts can be limited to levels that represent little or no risk through careful specification of the quantity of catalyst present. SCR may be applied to nearly all generating units, but must be managed to limit the formation of potentially harmful byproducts.

In Ontario, low NO_x burners have been installed at the Lambton and Nanticoke stations, and plans have been announced to install low NO_x burners at two of the four units at Lakeview. Low NO_x burners cost less than SCR and reduce NO_x emissions by a much smaller amount. SCR can be added to control NO_x in addition to low NO_x burners, and in general, the combination makes sense. The new gas-fired project planned at the Lakeview station has been proposed without SCR.

The incidence of SCR installations on new gas fired combined cycle power plants in the U.S. has grown considerably during the past decade. In many parts of the U.S. and abroad SCR has become a common component of a newly proposed gas fired power plants. Increased demand for SCR systems has resulted in a dramatic cost decrease during the past decade. Capital costs for SCR are currently estimated in the range of 28 Dollars² per kW to \$41/kW; less than 5% of the construction cost of new combined cycle plant capacity. The annualized costs to install and operate SCR at a large (500 MW) gas fired combined cycle facility in the Province of Ontario would likely amount to less than

¹ Appendix A provides greater details about the costs and performance of SCR controls.

² Exchange rate assumed to be 1.4767 Canadian/U.S. Source: Bloomberg, 10.22.99. Costs in the body of this report are presented in Canadian Dollars, while the costs in the Appendices (which emphasize U.S. experience) are presented in U.S. Dollars.

75 cents Canadian per customer per year. As more and more experience with SCR is obtained at both existing and new plants, costs will likely decrease even further.

2. U.S. Electric Generating Facility Air Pollution Regulatory Policy

During the past decade the U.S. Environmental Protection Agency and U.S. state air pollution regulatory agencies have placed considerable emphasis on reducing the NO_x emissions from fossil fuel burning electricity generation facilities. The impetus for this focus was manifested following the passage of the U.S. Clean Air Act Amendments of 1990 (CAAA) which required explicit reductions in the emissions of nitrogen oxides from existing fossil fuel (primarily coal) burning electricity generation plants.³

Although the CAAA emphasized reductions in emissions from existing facilities, newly proposed facilities became subject to a detailed emission control technology assessment that must be carried out prior to the commencement of construction of the proposed facility. This complex technology assessment forces project proponents to evaluate all available control technologies and those that are most effective in controlling NO_x emissions at an acceptable cost. The result of this process has been a marked increase in the use of post-combustion NO_x emission reduction technologies at new facilities.

In addition, US regulators are seeking options for reducing NO_x emissions from existing power plants, particularly in those regions of the country that are in nonattainment of the National Ambient Air Quality Standards (NAAQS). These efforts have resulted in greater regulatory pressure to install post-combustion control technologies on existing units, as well as the new ones.

3. SCR for New Generators in the U.S.

The U.S. Environmental Protection Agency stated in a recent analysis of “baseline air emission rates” that “[f]or new combined-cycle gas units, the EPA assumes that they will have NO_x combustion controls as well as SCR, resulting in an emission rate of 0.02 lbs. Per MMBtu” (EPA 1998, page A4-10).

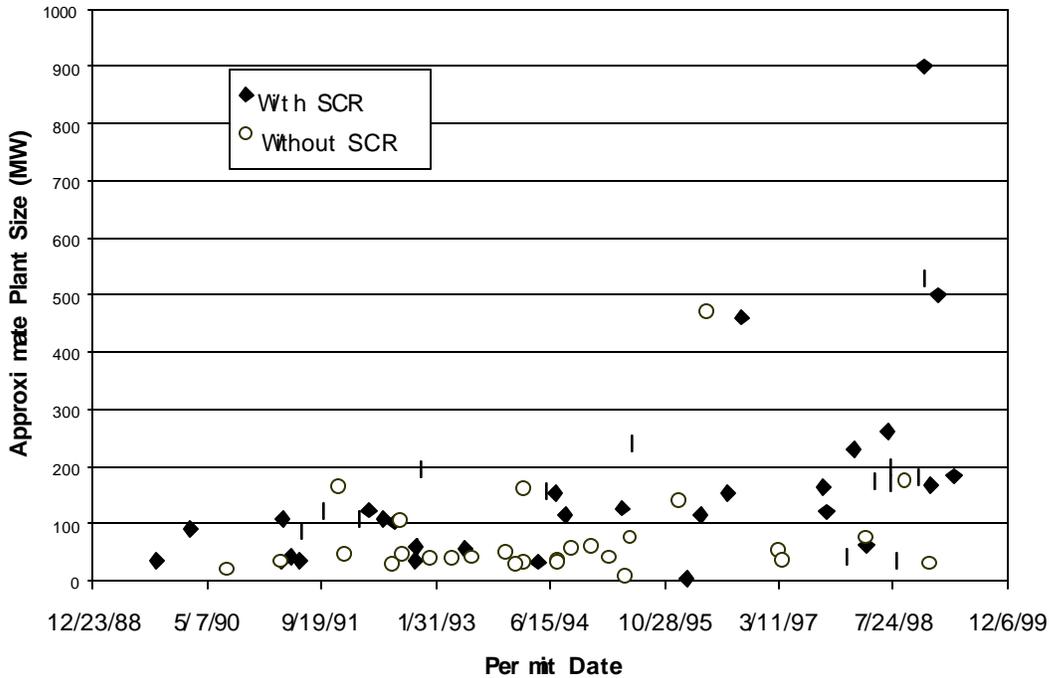
We have conducted an analysis of air permits for power plants using the EPA’s RBLC data. This is the “RACT/BACT/LAER Clearinghouse” data in which regulatory decisions are summarized, and made available online. We found that over the last decade in the U.S., more than 60% of the new combined cycle or cogeneration base load electricity generation facilities have been permitted with SCR for NO_x emissions control. There has been some trend over time to increased reliance upon SCR. In most parts of the U.S. developers proposing new plants now routinely propose SCR as part of a project. The control technology assessment process has established SCR as a cost effective means of reducing the emissions of nitrogen oxides from power plants.

The plot in Figure 1 shows that SCR for larger generating facilities, above about 100 MW, SCR is typically required in the U.S., and has been for many years. In this data set, which spans the last decade, there have been only six listed permits for gas combined

³ Appendix B provides greater details about the U.S. air quality regulations that affect the electricity industry

cycle plants larger than 100 MW for which SCR was not required. These tend to be special cases. For example, the largest of these was nuclear plant conversion to burn natural gas (the Fort St. Vrain plant in Colorado) and the most recent was an addition to a larger existing facility that opted for a new annual emissions cap for the total facility (the Champion plant in Maine).⁴

Figure 1 U.S. Power Plant Permits Issued With and Without SCR



For smaller facilities, under about 100 MW, the figure shows that SCR has often been required, but that it also common for permits to be issued that do not require SCR.

In recent years almost every newly proposed gas fired combined cycle project has included SCR technology for reducing NO_x emissions. In the northeastern and southwestern portion of the U.S. plants are proposed with SCR, and in some instances regulators are pressuring project proponents to consider installing an even more stringent control system called SCONOX (see Section 9, below). Even in states such as Illinois and Indiana, states with historically less stringent air pollution regulation, SCR is being recognized as the best available control technology and project proponents are submitting permit applications that include SCR systems.⁵

⁴ Personal communication with Sarah Anderson, at the Maine Department of Environmental Protection.

⁵ Personal communication with Nysa James at the Indiana Department of Environmental Management, Office of Air Management, and with Chris Romaine at the Illinois Bureau of Air Quality

In the U.S. nearly all new gas fired combined cycle power plants proposed or under construction include SCR systems.

4. SCR for Existing Generators in the U.S.

Not only are newly proposed plants using SCR, but existing electricity generation facilities are evaluating and beginning to install SCR in order to comply with the CAAA. At least six existing coal fuel power plants in the U.S. have already installed SCR systems in support of ozone transport region regulations (in place in most states in the northeastern portion of the U.S.).

Environmental regulators are also beginning to encourage the use of SCR controls on existing generation facilities. In September of 1998, the EPA promulgated a SIP Rule requiring 22 states in the eastern US to submit revised State Implementation Plans (SIPs) to achieve reductions in NO_x emissions. The SIP Rule establishes total NO_x budgets for each of the 22 states. The budgets were determined under the assumption that all electric generation facilities would be required by the states to achieve an emission rate of 0.15 lb/MMBtu. This emission rate was used because the EPA determined that it could be achieved through the installation of SCR controls on existing facilities (EPA 10/1998)⁶.

5. Canadian Experience with SCR

Mitsubishi Heavy Industries has installed three SCR systems at B.C. Hydro's Burrard Station, a gas-fired plant located near Vancouver. The cost of the SCR retrofits to Burrard units 4, 5, and 6 was less than \$28 per kW of capacity (Onishi et al 1998). The *SCR Turnkey Installation Experiences* report produced by Onishi, et al for Mitsubishi Heavy Industries America, Inc. in 1998 summarizes the B.C Hydro Burrard experience in the following:

The B.C. Hydro Burrard Thermal Generating Station is located at a few miles west of Vancouver, British Columbia, Canada in the city of Port Moody. The six boilers located at this site are externally similar and are each rated at 160 MW. The flue gas out from the boiler economizer is split into two trains supplying two regenerative Ljungstrom air preheaters. As a full turnkey project, the scope includes geo-tectonic investigation, engineering design, equipment fabrication and delivery, foundations, site demolition, construction, system start-up and performance testing, and personnel training. The actual operating conditions between units 4, 5 and 6. The design of each SCR unit is based on individual emissions baseline tests and miniature cold-flow model. While each retrofit was not considered particularly difficult, the confined space and low flue gas temperature at minimum load were of primary concern (Onishi).

6. International Experience with SCR

SCR technology was developed in Japan, where it has been in use since the mid 1970s (Buschmann and Larsson 1998). It has been in use at utility fossil fueled power plants in Germany and Japan since the mid 1980s (Tonn and Uysal 1998). The German

⁶ The EPA SIP Rule is described in more detail in Appendix B.

experience with SCR includes its use on eight coal stations totaling about 3100 MW of capacity, including one SCR installation, at the Hamburg Hafen plant, that has accumulated 75,000 hours of operation (Beckmann, et al 1998). SCR is now a mature technology, with its effectiveness proven in applications around the world. Mitsubishi Heavy Industries claims to have installed a total in excess of 300 SCR systems (Onishi et al 1998).

Recent SCR applications of note include a 2200 MW installation on a coal power plant in Taiwan (Tonn and Uysal 1998) and a 1000 MW installation on coal power plant in Japan (Onishi et al, 1998).

7. Costs of SCR

Given that the use of SCR in the U.S. has grown considerably during the past decade, SCR costs have dropped dramatically during the past ten years. As recently as the end of 1995, SCR capital costs were reported in the range of \$59-110/KW, while more recent capital cost estimates are on the order of \$28/kW to \$41/kW (EPA 3/98, and personal communication with Bob Fraser of ENSR Air Quality Engineering). The drastic reduction in capital costs is the result of competition among SCR manufacturers and the growing experience that manufacturers have gained as more systems have been installed. Clearly any impediments to the widespread adoption of SCR at both new and existing power plants are being eliminated⁷.

8. Ammonia

SCR's only identified drawback is its reliance on ammonia as a necessary input to the process. The primary components of an SCR system are an ammonia injection grid and a precious metal catalyst. Ammonia is uniformly injected into the exhaust gas stream from a combustion turbine or a conventional boiler at a point upstream of a precious metal catalyst substrate. The ammonia mixes with the exhaust gas and then passes over the catalyst which initiates a reaction where nitrogen oxides are converted to nitrogen and water. Unfortunately there has to be a small excess of ammonia injected to ensure a high removal efficiency and some ammonia will be emitted to the atmosphere. This very small quantity (5-30 parts per million) is referred to as "ammonia slip."

Ammonia itself is a noxious gas that can irritate the eyes and skin as well as create an explosive mixture when combined with oxygen (in air) at certain ratios. Although ammonia is dangerous, its use in the reduction of nitrogen oxide emissions from power plants has been allowed on numerous occasions. Regulatory agencies have determined that ammonia use that is governed by good management practices does not lead to unacceptable risks. Furthermore, in those instances where SCR systems are installed in populated areas, an aqueous ammonia solution can be utilized that reduces the risk of release. The fact that SCR requires the use of ammonia has not interfered with its increased use nor has it led to increased operational risks.

⁷ Information on NO_x control costs and performance is presented in Appendix A, using data from the U.S. Environmental Protection Agency. While SCR tends to have higher capital costs than some other post-combustion control technologies, it also has the highest NO_x emission reduction rates -- ranging from 70 to 80 percent removal.

9. Additional & Alternative NO_x Controls for New Gas Fired Combined Cycle Power Plants

Combustion controls offer additional options for new and existing power plants to lower nitrogen oxide emissions. For steam coal plants, low-NO_x burners (LNB) are used as the primary combustion control. For combustion turbine technologies, dry low-NO_x combustors are the primary combustion control option. With these types of controls designed to reduce the formation of nitrogen oxides during the combustion process, most combustion turbine manufacturers now offer machines with combustion controls as standard equipment. Not only do newly proposed power plants employ SCR, the equipment generating the emissions typically employs readily available technology to limit the formation of nitrogen oxides. The combination of both of these technologies is common for most proposed gas fired combined cycle power plants.

Recently an alternative to SCR called SCONO_xTM has been tested on a limited basis. The SCONO_xTM technology is attractive because it does not require ammonia and can reduce NO_x emissions to negligible levels (2-5 ppmvd). The process can operate at temperatures ranging from 300 to 700 degrees Fahrenheit and works by oxidizing CO to CO₂, NO to NO₂ and then absorbing the NO₂ onto its surface through the use of a special absorber coating (catalyst). A dilute hydrogen regeneration is then passed across the surface of the catalyst in the absence of oxygen. Hydrogen reacts with the absorbed NO_x to form nitrogen and water, which are exhausted into the atmosphere instead of NO_x (MacDonald). Unfortunately the system has not been tested on a large scale power plant (>30 MW) and many power plant developers have been skeptical toward adopting the technology. It is likely that the technology will be used more regularly when its development has been completed. Regardless of its current capability, air pollution regulators in the northeast and southwest of the U.S. are carefully monitoring the developments and have signaled that this more stringent control technology will likely become a “best available control technology” soon.

10. Conclusion

The installation of SCR systems on new gas fired combined cycle power plants and existing coal fired power plants in the U.S. and around the world has grown tremendously during the past decade. U.S. regulatory agencies, through implementation of the CAAA, have established SCR as the control technology of choice for nitrogen oxide emissions. Despite initial concerns expressed by industry and resistance by industry to its installation, the use of SCR has grown and its use is now widely accepted as standard technology. Companies using SCR have established considerable operational experience, which has provided evidence of the feasibility of the technology as well as the feedback SCR vendors require to improve the product and lower the costs. SCR technology is widely acknowledged to reduce power plant nitrogen oxide emissions to low levels at reasonable incremental cost.

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Individuals who provided useful information for this report:

- Sarah Anderson at the Maine Department of Environmental Protection, September, 1999.
- Bob Fraser of ENSR Air Quality Engineering, May 1999.
- Nysa James at the Indiana Department of Environmental Management, Office of Air Management, September, 1999.
- Chris Romaine at the Illinois Bureau of Air Quality, September, 1999.

Appendix A.

NO_x Control Options For Power Plants

Table A.1 presents a summary of the NO_x control technologies for achieving NO_x reductions in the electricity sector. All of the data in Table A.1 are taken from the EPA's study, *Analyzing Electric Power Generation Under the Clean Air Act* (EPA 3/1998).

The majority of the NO_x controls available are designed for coal plants. Some controls are applied in the combustion process itself, while others are applied after the fuel has been burned. On any one unit it is possible to apply both combustion and post-combustion controls. In such cases the removal rates are multiplicative.

The capital costs of the control technologies are levelized over thirty years using a fixed charge factor, in order to present total control costs in annual terms. We use a fixed charge factor of 10 percent, which assumes 25 percent debt financing at 7.5 percent, 75 percent equity financing at 15 percent, and includes federal income taxes, state income taxes, and local property taxes⁸. All costs presented in this Appendix are in 1997 dollars. We do not account for increases or decreases in control costs beyond inflation.

It is important to note that in practice, the cost of these control measures, and the amount of NO_x removal, might vary considerably from the costs presented in Table A.1. The cost might depend upon the unique characteristics of a unit's design, location, and operating patterns. For example, the costs of the SCR technologies installed to date have varied significantly.

Tables A.2 and A.3 present the control costs of typical existing coal units and new gas facilities, in terms of \$/ton removed and \$/MWh. For purposes of comparison, we assume that both units have a capacity of 400 MW and a capacity factor of 65 percent. The coal unit is assumed to be a dry-bottom, wall-fired unit, with a heat rate and an emission rate equal to the average rates of all US dry-bottom, wall-fired units in 1996.

The new gas unit is assumed to be a combined-cycle, with a heat rate and emission rate taken from EPA 1998. Smaller units will incur higher costs, due to the loss of economies of scale. Units with lower capacity factors will incur higher costs per ton and per MWh while those that operate more frequently will incur lower costs per ton and per MWh.

⁸ Resource Insight and Synapse Energy Economics 1999. *Avoided Energy Supply Costs for Demand-Side Management Screening in Massachusetts*, prepared for the Avoided Energy Supply Component Study Group, July 7.

Table A.1 NO_x Control Technology Costs and Removal Rates for Fossil Units.

Technology	Applicable Boiler Type	Capital Cost (\$/kW)	Capital Scaling ^(B)		Fixed O&M (\$/kW-yr)	Variable O&M (mills/kWh)	Removal Rate ^(C) (percent)
			Base	Factor			
Coal Units: Post-Combustion Controls:							
Selective Catalytic Reduction -- Low NO _x Rate		69.7	200	0.350	6.12	0.24	70.0
Selective Catalytic Reduction – High NO _x Rate		71.8	200	0.350	6.38	0.40	80.0
Selective Non-Catalytic Reduction – Low NO _x Rate		16.6	200	0.577	0.24	0.82	40.0
Selective Non-Catalytic Reduction – High NO _x Rate	Cyclone	9.6	100	0.577	0.14	1.27	35.0
Selective Non-Catalytic Reduction – High NO _x Rate		19.0	100	0.681	0.29	0.88	35.0
Gas Reburn – Low NO _x Rate		32.4	200	0.350	0.49	0.00	40.0
Gas Reburn – High NO _x Rate		32.4	200	0.350	0.49	0.00	50.0
Coal Units: Combustion Controls:							
Low NO _x Burner Without Overfire Air	Dry Bottom Wall-Fired	16.8	300	0.691	0.25	0.05	67.5
Low NO _x Burner With Overfire Air	Dry Bottom Wall-Fired	22.8	300	0.691	0.35	0.07	67.5
LNC 1 Close-Coupled Overfire Air ^(A)	Tangentially-Fired	32.3	300	0.624	0.49	0.00	47.3
LNC 2 Separated Overfire Air	Tangentially-Fired	34.7	300	0.624	0.53	0.00	52.3
LNC 3 Close-Coupled and Separated Overfire Air	Tangentially-Fired	46.7	300	0.624	0.71	0.02	57.3
Non Plug-In Controls	Cell Burners	22.8	300	0.315	0.34	0.07	60.0
Coal Reburning	Cyclone	70.7	300	0.388	1.07	0.25	50.0
NO _x Combustion Controls	Wet Bottom	9.6	300	0.553	0.14	0.05	50.0
NO _x Combustion Controls	Vertically Fired	10.8	300	0.553	0.17	0.05	40.0
Oil & Gas Units: Post-Combustion							
Gas Reburn – Combustion Control		19.8	200	0.557	0.30	0.03	50.0
Selective Catalytic Reduction		28.1	200	0.350	0.87	0.10	80.0
Selective Non-Catalytic Reduction		9.4	200	0.557	0.15	0.44	50.0

Source: EPA, March 1998, *Analyzing Electric Power Generation Under the CAAA*, Appendix No. 5. All costs are in 1997 dollars.

A. LNC 1, 2, and 3 all have low NO_x coal-and-air nozzles (LNC).

B. The capital cost scaling factors represent economies of scale, where the cost/kW for a particular unit is equal to the base size divided by the actual unit size, with the scaling factor as the exponent. For example, for the SCR – Low NO_x Rate at a 240 MW unit, the capital scaling factor cost would be 0.94, calculated as $(200 \text{ MW}/240 \text{ MW})^{0.35} = 0.94$. The size scaling factor for post-combustion controls reaches its limit at the capacity of 500 MW.

C. Each unit can have both post-combustion controls and combustion controls. The combined removal with the two types of NO_x controls is multiplicative.

Table A.2 NO_x Removal Costs for a Typical Existing Coal Unit

Fuel	BIT Bituminious	
Boiler	Dry Bottom (DB), Wall-fired	
Capacity	400 MW	
Heat Rate	10,325 Btu/kwh	1996 average for uncontrolled units
Capacity Factor	65%	
NO_x Rate	0.70 lbs/mmBtu	1996 average for uncontrolled units
Cap Rec Factor	10.0%	
Gas Reburn Adder	1.00 \$/mmBtu	Price difference between NG and Coal
Annual Generation	2,278	1000 MWhr
Annual NO_x	8,231 tons	

Technology	Capital Cost (\$/kW)	Fixed O & M (\$/kW-yr)	Variable O & M (mills/kWh)	Gas Use (%)	Removal (%)	Controlled Rate (lbs/mmBtu)	Removed (Tons)	Removal Costs (\$/ton)	(\$/MWh)
Combustion Controls									
LNB w/o OFA	16.8	0.25	0.05	0.00	46.7	0.373	3,841	199	0.34
LNB w OFA	22.8	0.35	0.07	0.00	46.7	0.373	3,841	273	0.46
Post Combustion Controls									
SCR Low NO _x	69.7	6.12	0.24	0.00	70.0	0.210	5,761	899	2.28
SCR High NO _x	71.8	6.38	0.40	0.00	80.0	0.140	6,585	868	2.51
SNCR - Low NO _x	16.6	0.24	0.82	0.00	40.0	0.420	3,292	732	1.06
SNCR - High NO _x	19	0.29	0.88	0.00	35.0	0.455	2,881	839	1.06
NG - Reburn Low NO _x	32.4	0.49	0.00	16.00	40.0	0.420	3,292	1,511	2.18
NG - Reburn High NO _x	32.4	0.49	0.00	16.00	50.0	0.350	4,115	1,209	2.18
Combination Controls									
LNB + SCR High NO _x					89.3	0.075	7,353	881	2.85
LNB + SNCR High NO _x					65.3	0.243	5,378	591	1.40
LNB + NG Reburn High NO _x					73.3	0.187	6,036	951	2.52

Table A.3 NO_x Removal Costs for a Typical New Gas Fired Combined Cycle Unit

Fuel Natural Gas
Boiler Combined Cycle (Heat Recovery Steam Generator)
Capacity 400 MW
Heat Rate 6,773 Btu/kwh
Capacity Factor 65%
NO_x Emission Rate 0.15 lbs/mmBtu
Cap Rec Factor 10.0%
Gas Reburn Adder 0.00 \$/mmBtu

Annual Generation 2,278 1000 MWhr
Annual NO_x 1,157 tons

Technology	Capital Cost (\$/kW)	Fixed O & M (\$/kW-yr)	Variable O & M (mills/kWh)	Gas Use (%)	Removal (%)	Controlled Rate (lbs/mmBtu)	Removed (Tons)	Removal Costs (\$/ton)	(\$/MWh)
Gas Reburn	19.80	0.30	0.03	16.00	50.00	0.075	578	1,256	0.32
SCR	28.10	0.87	0.10	0.00	80.00	0.030	926	1,575	0.64
SNCR	9.40	0.15	0.44	0.00	50.00	0.075	578	2,278	0.58
Low-NO _x Combined Controls	16.80	0.25	0.05	0.00	29.60	0.106	342	2,236	0.34
LN Comb. + SCR					85.90	0.021	994	2,236	0.98
LN Comb. + SNCR					64.80	0.053	750	2,778	0.91
LN Comb. + NG Reburn					64.80	0.053	750	1,990	0.65

Low-NO_x Combustion Controls assumed to have the same costs as LNB for coal plant. See OTAG 1996.

Appendix B.

Air Quality Regulations That Affect the U.S. Electricity Industry

B.1 Introduction

The 1990 United States Clean Air Act Amendments are the most recent and the most comprehensive in a series of U.S. federal clean air laws. The original Clean Air Act was passed in 1963. Amendments in 1970 and 1977 broadened and strengthened the Act considerably, and the 1990 Amendments added a comprehensive air toxics program and the first emission allowance trading program. Titles I and IV of the Clean Air Act (the Act) contain the primary laws applicable to the electric industry.

Title I of the Act provides for the National Ambient Air Quality Standards (NAAQS) for six “criteria” pollutants: SO₂, NO_x, ozone, carbon monoxide (CO), particulate matter (PM), and lead. The NAAQS are applied uniformly throughout the country, and responsibility for monitoring air quality and meeting the standards lies with states. Areas not meeting NAAQS for a criteria pollutant are designated “nonattainment” areas. Each state is required to submit to the EPA a State Implementation Plan (SIP) that outlines a strategy for bringing nonattainment areas into compliance with the law. Once a SIP is approved by the EPA, it is legally binding and enforceable by state or federal authorities.

Title I also includes regulations for new sources of air pollution. These regulations take the form of New Source Performance Standards (NSPS) for specific types of facilities and a federal New Source Review (NSR) program. The 1970 Amendments directed the EPA to establish NSPS for selected types of large stationary sources. In 1971 the Agency promulgated NSPS for steam electric generators with an electrical capacity of 100 MW or greater. These standards were revised in 1978, pursuant to the Amendments of 1977. In addition, the EPA recently issued new NSPS for NO_x emissions from new and modified utility (and industrial) boilers.⁹

The 1977 Amendments also established the NSR process, which allows standards for new sources to evolve along with advancing technology and which applies different standards in attainment and nonattainment areas. New sources in nonattainment areas are required to install state-of-the-art emission control technology and to obtain offsets for all emissions.

The 1990 Amendments established the Acid Rain Program, in Title IV of the Act. The program is designed to reduce annual SO₂ emissions by 10 million tons (to roughly 1980 levels). Central to the program is the SO₂ cap and trade system, which allocates tradable SO₂ allowances to the affected plants. The Acid Rain Program also addresses NO_x emissions, by imposing NO_x emission standards on existing coal facilities. The program is being implemented in two phases: Phase I began in January of 1995, and Phase II will begin in January of 2000.

In addition to the Acid Rain Program, there are two regional allowance programs in the U.S., one in the Northeast and the other in Southern California. In the Northeast, the Ozone Transport

⁹ In November of 1998 EPA’s revised NSPS for NO_x emissions from utility and industrial boilers became effective. The new rule will affect boilers at which construction, modification or reconstruction is commenced after July 9, 1997. For new utility boilers, the standard is 1.6 lb/MWH gross energy output; major modifications trigger a standard of 0.15 lb/MMBtu heat input. The move to an output-based standard for new plants is significant, and may become a model for future regulations (See Section 8).

Commission (OTC) was established in 1994. States in the OTC have developed a regional strategy for controlling emissions of ozone precursors, and a NO_x cap and trade program is central to this strategy.

Finally, a large-scale NO_x allowance trading program would be implemented across the eastern U.S. as a result of EPA's NO_x SIP Rule. In September of 1998, the EPA promulgated a rule requiring the 22 eastern-most states to submit revised SIPs that would achieve additional reductions in NO_x emissions. The rule establishes NO_x budgets for the affected states and rules for compliance.

B.2 New Source Review and Emission Offsets

All areas of the U.S. are currently classified as being in either attainment or nonattainment of the NAAQS for each of the criteria pollutants. Although much progress in improving air quality has been made over the past three decades, a number of areas in the country remain in nonattainment for one or more pollutants. Nonattainment of the ozone standard is most widespread.

In response to mounting evidence of human health and ecosystem impacts of ozone, the EPA revised the NAAQS for ozone in 1997. The new NAAQS require that air quality be measured over an eight-hour period, as opposed the previous NAAQS that was limited to a one-hour measurement period. The new NAAQS also establish a more stringent standard than the previous one. During the next several years, the attainment status of many areas of the country will be reclassified, enlarging many existing nonattainment areas for ozone and adding new ones.¹⁰

The NSR program determines technology-based standards, on a case-by-case basis for "major" new facilities and "major modifications" to existing facilities. The technology-based standards are intended to be revised periodically, and to evolve to become more and more stringent as control technologies become more effective and efficient over time.

In attainment areas, the NSR standards are designed to "prevent significant deterioration" (PSD) of the area's air quality. Major new sources are required to utilize the "best available control technology" (BACT), as determined by EPA, and to model local air quality to demonstrate that the additional emissions will not significantly impact air quality.¹¹ PSD provisions do not generally require existing sources to reduce emissions in attainment areas.

In nonattainment areas, the NSR rules are more stringent. Existing sources are required to utilize "reasonably available control technologies" (RACT).¹² Major new sources are required to utilize the "lowest achievable emission rate" technology (LAER) and to obtain offsets for any residual emissions.¹³ Offsets are units of reduced emissions (denominated in tons per year) obtainable from (a) existing sources that have reduced their emissions below all applicable requirements, or (b) facilities that are shut down before the end of their useful lives. Subject to certain limitations, NSR offsets can be traded or "banked" for future use.

¹⁰ On May 14, 1999, the U.S. Court of Appeals for the D.C. Circuit remanded the new primary and secondary NAAQS for ozone and particulates in *American Trucking Association v. EPA*. The EPA is currently developing its response to the court remand.

¹¹ BACT is generally held to be the lowest emission rate that can be achieved at a reasonable cost.

¹² RACT is defined as the control technology that is reasonably available considering technological and economic feasibility.

¹³ LAER is generally held to be the most stringent proven emission control technology available; consideration of costs is expressly forbidden in determining LAER.

B.3 Title IV NO_x Standards For Existing Sources

Coal-fired sources that are subject to the Title IV Acid Rain Program will be required to meet emission standards for NO_x, in addition to complying with the SO₂ cap and trade program. Coal boilers are divided into two groups. Group I boilers include dry bottom wall-fired boilers and tangentially-fired boilers. Group II boilers include virtually all other types of coal boilers. Phase I of the Acid Rain Program requires Group I boilers to meet NO_x emission standards by 1995. Phase II requires that by 2000 Group I boilers meet more stringent standards, and Group II boilers meet NO_x emission standards. These NO_x standards are summarized in Table 2.3.

Table 2.3 Title IV NO_x Standards for Existing Coal Units

Boiler Type	Phase I -- 1995 (lb/MMBtu)	Phase II -- 2000 (lb/MMBtu)	Number of Boilers in US
Dry-bottom wall-fired	0.50	0.46	308
Tangential-fired	0.45	0.40	299
Cell burners	No standards	0.68	36
Cyclones (>155 MW)	No standards	0.86	55
Wet bottoms (>65 MW)	No standards	0.84	26
Vertically-fired	No standards	0.80	28

B.4 NO_x Cap and Trade Programs

The OTC NO_x Budget Program

The 1990 Amendments to the Clean Air Act also mandated the establishment of the Ozone Transport Commission (OTC), to be composed of the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, the four northern counties of Virginia and the District of Columbia. While all U.S. states are required to implement certain emission reduction programs in ozone nonattainment areas, OTC states were charged with developing additional regional strategies for controlling emissions of ozone precursors. In September of 1994, the OTC states adopted an Memorandum of Understanding to implement a regional “NO_x Budget Program” to reduce NO_x emissions during the ozone season.

The OTC does not have the authority to adopt or enforce regulations; rather the member states implement and enforce regional solutions on a state-by-state basis. In June of 1995, the OTC states agreed on the number of NO_x allowances to be allocated to each state beginning in 1999. States, in turn, allocate allowances to large stationary sources of NO_x – utility and industrial boilers with capacities equal to, or greater than, 250 MMBtu per hour of heat input or with electricity output of 15 MW or greater. As in the Acid Rain Program, sources must hold an allowance for each ton of NO_x emitted, and sources can trade allowances or bank them for future use.

The OTC NO_x Budget Program will require two phases of reductions. Compliance with the first phase began during the ozone season of 1999 (May 1 through September 30), and compliance with the second phase will begin during the ozone season of 2003. In 1990, summer emissions from the affected sources in the OTC totaled 490,741 tons. In 1999, summer NO_x emissions are capped at 290,000 tons. By 2003, this program is expected to reduce summer NO_x emissions from affected sources to 142,874 tons.

Determination of how new sources will acquire OTC NO_x Budget allowances has been made at the state level. Some states are setting aside a specific number of allowances each year for sale or distribution to new sources, while other states will require new sources to obtain allowances in the market.

During most of the period leading to the commencement of the OTC NO_x Budget Program, NO_x allowances traded at prices in the range of \$1,000 to \$2,000 per ton, consistent with the estimated cost of controls at affected sources. In the spring of 1999 there was a significant increase in the price of allowances, with some trades reportedly occurring at over \$7,000 per ton. This price spike was most likely due to last-minute changes in companies' compliance plans and uncertainty over the commencement of the new program. By mid-summer 1999 prices had fallen back to levels below \$2,000 per ton.

The EPA's NO_x SIP Rule

EPA's NO_x SIP Rule includes a widespread allowance-based trading program. In September of 1998, EPA promulgated a rule requiring 22 states in the eastern U.S. to submit revised SIPs that would achieve additional reductions in NO_x emissions. In the rule, EPA established a NO_x budget for the affected states and rules for compliance.

EPA's NO_x SIP Rule includes a model trading rule for large sources of NO_x, but states will have the final authority to design and establish NO_x trading mechanisms. While states will have the flexibility to allocate reductions among the various source categories – e.g., transportation, industry, etc. – power plants are expected to bear the responsibility for major NO_x reductions in most states.

Under EPA's NO_x SIP Rule, NO_x emissions from each of the 22 affected states will be capped during the ozone season (May through September). States must comply with the cap beginning in May of 2003. State caps or "budgets" were developed through detailed analyses of baseline emissions and potential reductions from five source sectors: electricity generating units, other point sources, stationary area sources, on-road mobile sources, and off-road mobile sources.

State budgets for electric generators were developed by applying a NO_x emission rate of 0.15 lb/MMBtu to all fossil-fired turbines and boilers connected to generators 25 MW in size or greater. This emission rate was chosen based on projections of the necessary reductions and the cost-effectiveness of various NO_x control options. The EPA determined that this emission rate could be achieved on average across the 22-state region at an average cost of \$1,468 per ton removed, assuming a multi-state trading program was adopted.

To allocate allowances to states, the EPA developed state budgets for electric generators and four other source categories. For electric generators, the 0.15 lb/MMBtu emission rate was applied to the heat input of each large, fossil-fired unit in the state. (The heat input used for each unit was the average of the two highest heat input figures for the 1995, 1996 and 1997 ozone seasons.) This allocation method yielded a 22-state ozone season NO_x cap for electric generators of 543,825 tons.

As promulgated, EPA's SIP Rule requires states to submit revised SIPs by September of 1999. However, in May of 1999 the Court of Appeals for the D.C. Circuit granted the motion of eight petitioning states to stay the submission of revised SIPs pending further order of the court. The court based its decision not on the merits of the science, but in order to allow the parties involved to argue the case before the court. This partial stay will prevent the EPA from implementing the NO_x SIP Rule until the final ruling on this case. During the summer of 1999, negotiations took place around several competing settlement proposals. However, EPA and the states involved in

these negotiations could not reach agreement on a settlement, and parties are now focusing on the impending hearings.

Section 126 Petitions to the EPA

In 1997 eight northeastern states filed petitions with the EPA regarding the transport of NO_x and ozone from upwind states, pursuant to Section 126 of the Clean Air Act. The states claim that a group of electricity power plants in the Midwest produce NO_x emissions that significantly contribute to the ozone problem in their states and prevent them from attaining the ambient air quality standards for ozone. The states claim that the transport of ozone is so extensive that they will not be able to attain ozone standards without substantial reductions in ozone transport from upwind areas.

If the EPA determines that an upwind source is emitting a pollutant that significantly inhibits another state from reaching attainment, then the source must cease operation within three months, unless the EPA permits it to continue to operate under a plan to reduce emissions as expeditiously as practical. In their petitions, the states are asking the EPA to establish emission limitations for the upwind plants sufficient to prevent them from significantly contributing to ozone levels within the downwind states.

The EPA has not acted on the Section 126 Petitions, because the NO_x SIP Rule would address the complaints raised by the petitioners. If the NO_x SIP Rule is abandoned as a consequence of the current court challenge, then the Section 126 Petitions provide a backup option to achieve many of the same goals as the SIP Rule. Many, but not all, of the power plants affected by the SIP Rule would also be affected by the Section 126 Petition. While the Section 126 Petitions do not include a NO_x cap and trade system, if it eventually becomes the alternative to the SIP call, there is a good chance that such a system will be incorporated into it.

Appendix C.

Permits For Combined Cycle and Cogeneration Plants Listed in the EPA's RBLC Data

This Appendix presents two tables, listing baseload power plants in the U.S. permitted with and without SCR technology for NO_x emissions control.

Table C.1

U.S. Power Plants Permitted with SCR Technology

(Developed from information in the EPA RACT/BACT/LAER Clearinghouse Database)

FACILITY	STATE	PERMIT DATE	PROCESS
PDC EL PASO MILFORD LLC	CT	4/16/99	TURBINE, COMBUSTION, ABB GT-24, #1 WITH 2 CHILLERS
WYANDOTTE ENERGY	MI	2/8/99	TURBINE, COMBINED CYCLE, POWER PLANT
MOBILE ENERGY LLC	AL	1/5/99	TURBINE, GAS, COMBINED CYCLE
GORHAM ENERGY LIMITED PARTNERSHIP	ME	12/4/98	TURBINE, COMBINED CYCLE
WESTBROOK POWER LLC	ME	12/4/98	TURBINE, COMBINED CYCLE, TWO
LSP - COTTAGE GROVE, L.P.	MN	11/10/98	GENERATOR, COMBUSTION TURBINE & DUCT BURNER
TNP TECHN, LLC (FORMERLY TX-NM POWER CO.)	NM	8/7/98	GAS TURBINES
CASCO RAY ENERGY CO	ME	7/13/98	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO
CITY OF LAKELAND ELECTRIC AND WATER UTILITIES	FL	7/10/98	TURBINE, COMBUSTION, GAS FIRED W/ FUEL OIL ALSO
BRIDGEPORT ENERGY, LLC	CT	6/29/98	TURBINES, COMBUSTION MODEL V84.3A, 2 SIEMES
RUMFORD POWER ASSOCIATES	ME	5/1/98	TURBINE GENERATOR, COMBUSTION, NATURAL GAS
ANDROSCOGGIN ENERGY LIMITED	ME	3/31/98	GAS TURBINES, COGEN, W/DUCT BURNERS
MILLENNIUM POWER PARTNER, LP	MA	2/2/98	TURBINE, COMBUSTION, WESTINGHOUSE MODEL 501G
BASF CORPORATION	LA	12/30/97	TURBINE, COGEN UNIT 2, GE FRAME 6

<u>FACILITY</u>	<u>STATE</u>	<u>PERMIT DATE</u>	<u>PROCESS</u>
DIGHTON POWER ASSOCIATE, LP	MA	10/6/97	TURBINE, COMBUSTION, ABB GT11N2
BERKSHIRE POWER DEVELOPMENT, INC.	MA	9/22/97	TURBINE, COMBUSTION, ABB GT24
ECOELECTRICA, L.P.	PR	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION
BLUE MOUNTAIN POWER, LP	PA	7/31/96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER
MID-GEORGIA COGEN.	GA	4/3/96	COMBUSTION TURBINE (2), FUEL OIL
TULLYTOWN RESOURCE RECOVERY FACILITY	PA	2/1/96	MUNICIPAL WASTE LANDFILL WITH FOUR LFG TURBINES
BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NY	6/6/95	TURBINE, NATURAL GAS FIRED
SACRAMENTO POWER AUTHORITY CAMPBELL SOUP	CA	8/19/94	TURBINE, GAS , COMBINED CYCLE, SIEMENS V84.2
HERMISTON GENERATING CO.	OR	7/7/94	TURBINES, NATURAL GAS (2)
PORTLAND GENERAL ELECTRIC CO.	OR	5/31/94	TURBINES, NATURAL GAS (2)
FLEETWOOD COGENERATION ASSOCIATES	PA	4/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	6/9/93	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)
SITHE/INDEPENDENCE POWER PARTNERS	NY	11/24/92	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)
KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	NY	11/9/92	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW)
KAMINE/BESICORP CORNING L.P.	NY	11/5/92	TURBINE, COMBUSTION (79 MW)
GOAL LINE, LP ICEFLOE	CA	11/3/92	TURBINE, COMBUSTION (NATURAL GAS) (42.4 MW)
BEAR ISLAND PAPER COMPANY, L.P.	VA	10/30/92	TURBINE, COMBUSTION GAS
GORDONSVILLE ENERGY L.P.	VA	9/25/92	TURBINE FACILITY, GAS
SARANAC ENERGY COMPANY	NY	7/31/92	TURBINES, COMBUSTION (2) (NATURAL GAS)
SELKIRK COGENERATION PARTNERS, L.P.	NY	6/18/92	COMBUSTION TURBINES (2) (252 MW)

<u>FACILITY</u>	<u>STATE</u>	<u>PERMIT DATE</u>	<u>PROCESS</u>
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	RI	4/13/92	TURBINE, GAS AND DUCT BURNER
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	3/3/92	TURBINE, COMBUSTION
EEX POWER SYSTEMS, ENCOGEN NW COGENERATION PROJECT	WA	9/26/91	TURBINES, COMBINED CYCLE COGEN, GE FRAME 6
SUMAS ENERGY INC.	WA	6/25/91	TURBINE, NATURAL GAS
SAGUARO POWER COMPANY	NV	6/17/91	COMBUSTION TURBINE GENERATOR
GRANITE ROAD LIMITED	CA	5/6/91	TURBINE, GAS, ELECTRIC GENERATION
NORTHERN CONSOLIDATED POWER	PA	5/3/91	TURBINES, GAS, 2
LAKWOOD COGENERATION, L.P.	NJ	4/1/91	TURBINES (NATURAL GAS) (2)
CIMARRON CHEMICAL	CO	3/25/91	TURBINE #2, GE FRAME 6
PEDRICKTOWN COGENERATION LIMITED PARTNERSHIP	NJ	2/23/90	TURBINE, NATURAL GAS FIRED
KINGSBURG ENERGY SYSTEMS	CA	9/28/89	TURBINE, NATURAL GAS FIRED, DUCT BURNER
UNOCAL	CA	7/18/89	TURBINE, GAS (SEE NOTES)
PILGRIM ENERGY CENTER	NY		(2) WESTINGHOUSE W501D5 TURBINES (EP #S 00001&2)

Table C.2

U.S. Power Plants Permitted without SCR Technology

(Developed from information in the EPA RACT/BACT/LAER Clearinghouse Database)

<u>FACILITY</u>	<u>STATE</u>	<u>PERMIT DATE</u>	<u>PROCESS</u>
COLORADO SPRINGS UTILITIES	CO	1/4/99	TURBINE, COMBINE, NATURAL GAS FIRED
CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	ME	9/14/98	TURBINE, COMBINED CYCLE, NATURAL GAS
STAR ENTERPRISE	DE	3/30/98	TURBINES, COMBINED CYCLE, 2
COLO. POWER PARTNERS-BRUSH COGEN FAC	CO	3/27/97	COGEN TURBINES W/ DUCT BURNERS & BOILERS
MEAD COATED BOARD, INC.	AL	3/12/97	COMBINED CYCLE TURBINE (25 MW)
TEMPO PLASTICS	CA	12/31/96	GAS TURBINE COGENERATION UNIT
PUBLIC SERVICE OF COLO.-FORT ST VRAIN	CO	5/1/96	COMBINED CYCLE TURBINES (2), NATURAL
SEMINOLE HARDEE UNIT 3	FL	1/1/96	COMBINED CYCLE COMBUSTION TURBINE
PANDA-KATHLEEN, L.P.	FL	6/1/95	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115MW)
HOFFMAN-LA ROCHE, NUTLEY COGEN FACILITY	NJ	5/8/95	TURBINE, GM LM500
FORMOSA PLASTICS CORPORATION, LOUISIANA	LA	3/2/95	TURBINE/HRSG, GAS COGENERATION
KAMINE/BESICORP SYRACUSE LP	NY	12/10/94	SIEMENS V64.3 GAS TURBINE (EP #00001)
FULTON COGEN PLANT	NY	9/15/94	STACK EMISSIONS (GAS TURBINE AND DUCT BURNER)
INTERNATIONAL PAPER	LA	2/24/94	TURBINE/HRSG, GAS COGEN
TECO POLK POWER STATION	FL	2/24/94	TURBINE, SYNGAS (COAL GASIFICATION)
KAMINE/BESICORP CARTHAGE L.P.	NY	1/18/94	STACK (GAS TURBINE & DUCT BURNER) **SEE NOTE #3**
SUNLAW COGEN. (FEDERAL COLD STORAGE COGENERATION)	CA	1/15/94	TURBINE, NATURAL GAS FIRED, COMBINED CYCLE AND COG
<u>FACILITY</u>	<u>STATE</u>	<u>PERMIT DATE</u>	<u>PROCESS</u>

PROJECT ORANGE ASSOCIATES	NY	12/1/93	GE LM-5000 GAS TURBINE
ANITEC COGEN PLANT	NY	7/7/93	GE LM5000 COMBINED CYCLE GAS TURBINE EP #00001
TRIGEN MITCHEL FIELD	NY	4/16/93	GE FRAME 6 GAS TURBINE
INTERNATIONAL PAPER CO. RIVERDALE MILL	AL	1/11/93	TURBINE, STATIONARY (GAS-FIRED) WITH DUCT BURNER
KAMINE SOUTH GLENS FALLS COGEN CO	NY	9/10/92	GE FRAME 6 GAS TURBINE
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	NY	9/1/92	TURBINE, COMBUSTION GAS (150 MW)
MAUI ELECTRIC COMPANY, LTD./MAALAEA GENERATING STA	HI	7/28/92	TURBINE, COMBINED-CYCLE COMBUSTION
KAMINE/BESICORP NATURAL DAM LP	NY	12/31/91	GE FRAME 6 GAS TURBINE
KALAMAZOO POWER LIMITED	MI	12/3/91	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS
CIMARRON CHEMICAL	CO	3/25/91	TURBINE #1, GE FRAME 6
TBG COGEN COGENERATION PLANT	NY	8/5/90	GE LM2500 GAS TURBINE
MEGAN-RACINE ASSOCIATES, INC	NY	8/5/89	GE LM5000-N COMBINED CYCLE GAS TURBINE
BRUSH COGENERATION PARTNERSHIP	CO		TURBINE
COLORADO POWER PARTNERSHIP	CO		TURBINES, 2 NAT GAS & 2 DUCT BURNERS