WHITE PAPER

SELECTIVE CATALYTIC REDUCTION (SCR) CONTROL OF NO_x EMISSIONS

PREPARED BY:

SCR COMMITTEE

INSTITUTE OF CLEAN AIR COMPANIES, INC.

NOVEMBER 1997

1660 L Street NW
Suite 1100
Washington, DC 20036-5603
Telephone 202.457.0911
Fax 202.331.1388

Jeffrey C. Smith, *Executive Director*
e-mail: jsmith@icac.com

Michael J. Wax, Ph.D., *Deputy Director*
e-mail: mwax@icac.com

INSTITUTE OF CLEAN AIR COMPANIES

The Institute of Clean Air Companies, the nonprofit national association of companies that supply stationary source air pollution monitoring and control systems, equipment, and services, was formed in 1960 to promote the industry and encourage improvement of engineering and technical standards.

The Institute's mission is to assure a strong and workable air quality policy that promotes public health, environmental quality, and industrial progress. As the representative of the air pollution control industry, the Institute seeks to evaluate and respond to regulatory initiatives and establish technical standards to the benefit of all.

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EXECUTIVE SUMMARY

Nitrogen oxides (NO_x) emissions contribute significantly to national environmental problems, including acid rain, photochemical smog (ozone), and elevated fine particulate levels. As of 1997, more than 100 million Americans lived in counties with unhealthy ozone levels. To protect both human health and the environment, NO_x levels thus must be lowered. The process which can reduce NO_x emissions most from many industrial and utility sources is selective catalytic reduction (SCR).

First patented by a U.S. company in 1959, SCR is a proven technology used to significantly reduce NO_x emissions from more than 300 sources in the U.S., and more than 500 sources worldwide. In the U.S., SCR has been applied on utility and industrial boilers, gas turbines, process heaters, internal combustion engines, chemical plants, and steel mills. Emissions reductions of greater than 90% are common with SCR, although this technology may be used economically for lower removal efficiencies as well.

Perceived high cost has been an impediment to the adoption of SCR in the U.S. While this perception has been based largely on incorrect information, both the capital and operating costs of SCR have dropped significantly over the past decade because of technological innovation, increased manufacturing experience, and competition among manufacturers. Much longer expected catalyst lives have contributed to the reduced operating cost.

Decreased costs, successful operating experience, and tightened permit limits have led to a sharp increase in the number of SCR systems installed in the U.S. Given a large and growing installed base and the increasing tendency of owners and operators of regulated units to choose SCR, authorities with extensive NO_x control experience have concluded that SCR technology is proven, safe, reliable, and economical.

Why Should We Control NO_x Emissions?

NO_x harms human health and the environment directly and by contributing to photochemical smog, atmospheric fine particulate, acid rain, and nitrogen deposition.

Nitrogen oxides (NO_x) include nitric oxide (NO) and nitrogen dioxide (NO_2), and are produced by the oxidation of atmospheric and fuel-bound nitrogen in combustion processes, including those in motor vehicles and industrial facilities. Nitric oxide is a colorless gas that is converted in the atmosphere to yellowish-brown NO_2.

In 1995, national emissions of NO_x were 21.8 million tons. Electric utility and industrial fuel combustion contributed 9.4 million tons of NO_x, with most of the remainder coming from mobile sources.[1]

Nitrogen oxides harm human health and the environment both directly and indirectly, as summarized below.[2]

Nitrogen dioxide can cause adverse human health effects, including bronchitis, pneumonia, lung irritation, and susceptibility to viral infection. Animal studies show that intermittent, low-level NO_2 exposures also can induce alterations in the kidney, liver, spleen, red blood cells, and cells of the immune system.[3]

NO_x emissions lead to the formation of ground-level ozone (photochemical smog). Unlike ozone in the stratosphere, ozone at ground level has a strong negative impact on human health and the environment. Ozone impairs lung function and aggravates heart disease and respiratory diseases such as asthma and bronchitis.[4] Ozone also causes such negative environmental effects as crop and forest damage and visibility impairment.[5]

EPA estimates that more than 100 million Americans live in counties exceeding the national ozone air quality standard, making ozone a pervasive air problem.[2] Analyses done by the Ozone Transport Assessment Group show that significant NO_x reductions are necessary to solve the ozone non-attainment problem in the U.S.[6]

NO_x reacts to form fine particulate in the atmosphere. Nitrogen oxides react with oxygen and other components of air to form nitrates, which coalesce into fine particles. Studies of collected $PM_{2.5}$ (particulate with a diameter less than 2.5 micrometers) suggest that nitrate makes up more than 10% of the mass of fine particulate in the western two-thirds of the country.[7] Recent research showing that fine particulate increases human death rates and exacerbates respiratory and circulatory diseases highlights[8] the importance of lowering the concentration of fine particulate and its precursors.[9]

NO_x emissions contribute to acid rain and nitrogen deposition. Nitrogen oxides contribute to the formation of acid rain, which has been shown to destroy fish and other forms of fresh and coastal water life, and to damage buildings and materials, forests, and agricultural crops. In some western areas of the United States, NO_x emissions are the primary cause of acid deposition. In the East, NO_x emissions are responsible for about one-third of rainfall's acidity over the full year, and one-half during the winter.[10]

NO_x also contributes to nitrification of rain, which may "over-fertilize" the soil, leaving foliage more vulnerable to damage from cold, insects, and disease. Nitrification can also upset the ecological balance on both land and water.[11]

What is SCR?

In the SCR process, a catalyst facilitates a chemical reaction between NO_x and ammonia to produce nitrogen and water. An ammonia-air or ammonia-steam mixture is injected into exhaust gases containing NO_x. The gases mix thoroughly in a turbulent zone, and then pass through the catalyst where the NO_x is reduced. The catalyst promotes the reaction, but is not consumed by it.

SCR is a process for controlling emissions of nitrogen oxides from stationary sources. The basic principle of SCR is the reduction of NO_x to N_2 and H_2O by the reaction of NO_x and ammonia (NH_3) within a catalyst bed. The primary reactions occurring in SCR are given below. Note that these reactions require oxygen, so that catalyst performance is best at oxygen levels above 2-3%.[12]

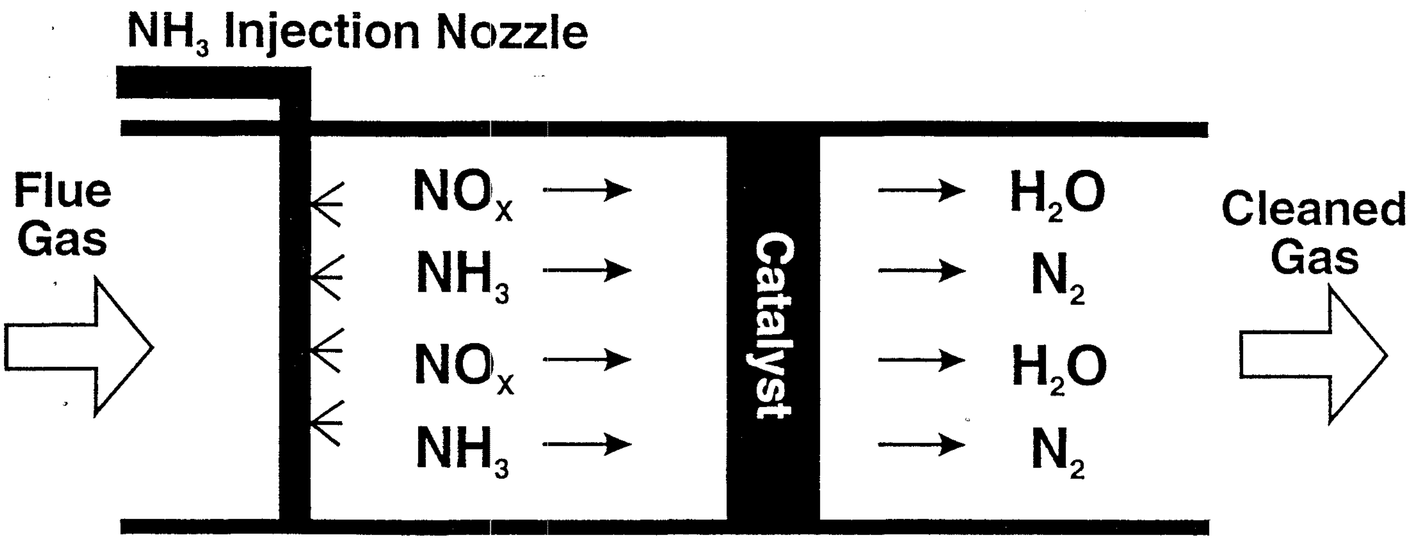
$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

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

Several different catalysts are available for use at different exhaust gas temperatures. In use the longest are base metal catalysts, which typically contain titanium and vanadium oxides, and which also may contain molybdenum, tungsten, and other elements. Base metal catalysts are useful between 450 °F and 800 °F. For high temperature operation (675 °F to over 1100 °F), zeolite catalysts may be used. In clean, low temperature (350-550 °F) applications, catalysts containing precious metals such as platinum and palladium are useful. (Note that these compositions refer to the catalytically active phase only; additional ingredients may be present to give thermal and structural stability, to increase surface area, or for other purposes.)

The mechanical operation of an SCR system is quite simple. It consists of a reactor chamber with a catalyst bed, composed of catalyst modules, and an ammonia handling and injection system, with the NH_3 injected into the flue gas upstream of the catalyst as shown in Figure 1. (Occasionally, a fluidized bed of catalyst pellets is used.) SCR systems have no moving parts. Other than spent catalyst, the SCR process produces no waste products.

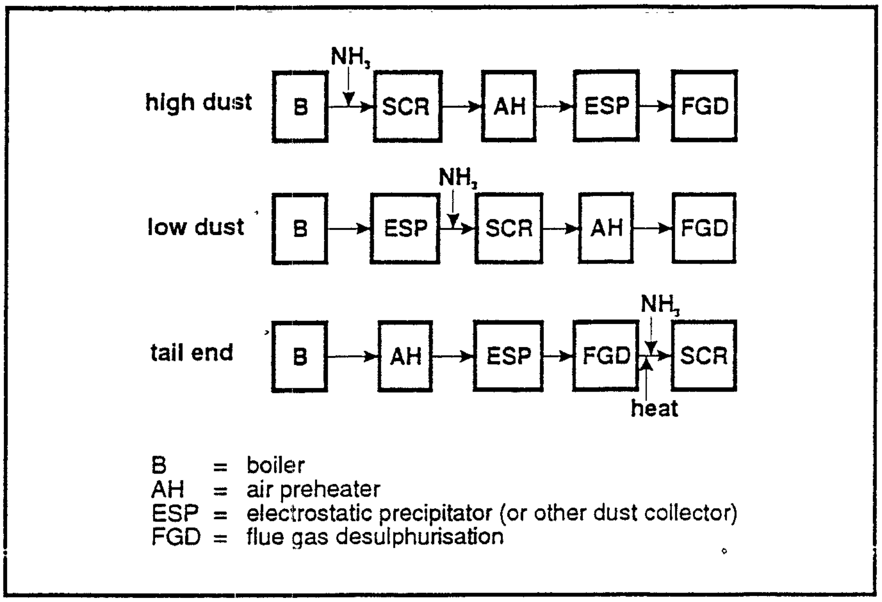
Figure 1. Schematic Diagram of a Generic SCR System



In utility boiler applications in the U.S., the catalyst has been placed in a separate housing upstream of the air preheater and of any particulate collection device (see Figure 2). This "high-dust" hot-side configuration is less expensive to install and operate than other configurations. In several units in California[13] and in a demonstration in a coal-fired boiler in New Jersey,[14] the catalyst has been installed in expanded ductwork between the economizer and preheater ("in-duct SCR") to meet space constraints and lower capital costs further. Use of preheater baskets coated with active catalyst material ("preheater SCR") to shrink the size of the catalytic reactor or to reduce ammonia slip from upstream NO_x removal processes,[15] has been the subject of several demonstrations.[16]

Figure 2. (a) SCR System Configurations for Utility Boiler Applications; (b) Schematic Diagram of a High-Dust Hot-Side SCR System

(a)



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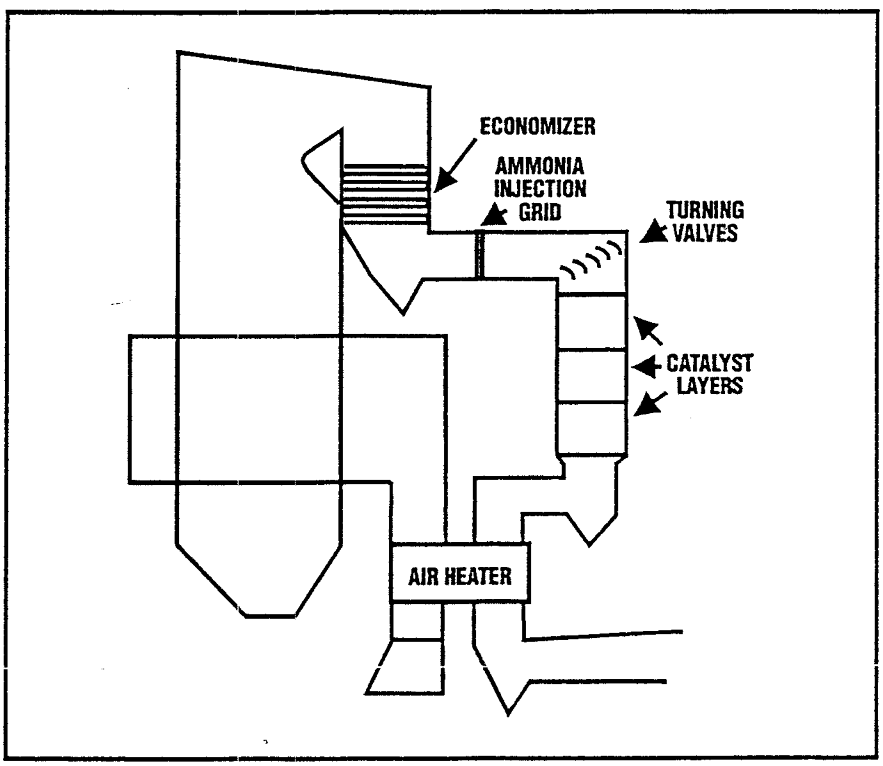
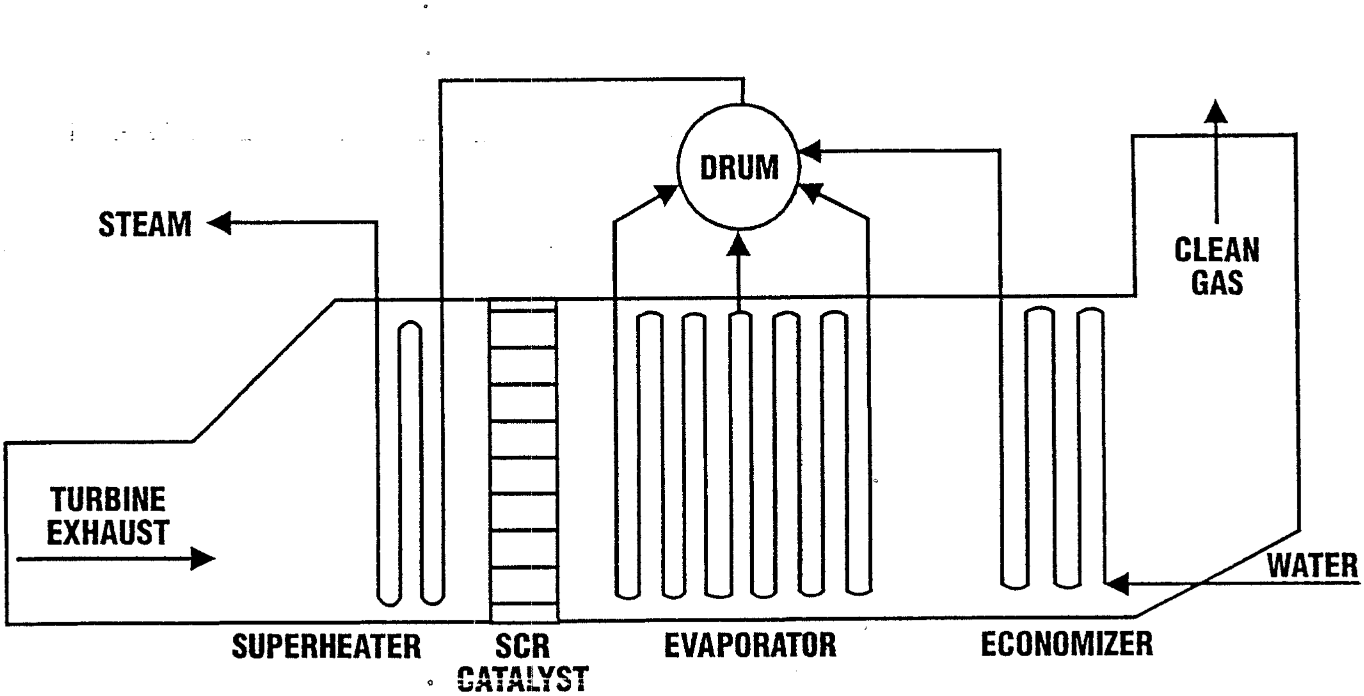


Figure 3. SCR Catalyst Placement for Gas Turbine Applications



In combined-cycle gas turbine applications, the catalyst normally is placed after the superheater in the heat recovery steam generator (HRSG), where the temperature is in the range suitable for base metal operation (see Figure 3). At several sites in the U.S., high-temperature (zeolite) catalyst has been installed upstream of the HRSG or at the turbine exhaust in simple-cycle applications, where the temperature may be as high as 950-1050 °F.[17]

How Much NO_x Can SCR Remove?

By proper catalyst selection and system design, NO_x removal efficiencies exceeding 90% may be achieved. In practice, SCR systems designed for a wide range of NO_x removal efficiencies have proven economical.

In principle, SCR can provide reductions in NO_x emissions approaching 100%. (Simple thermodynamic calculations indicate that a reduction of well over 99% is possible at 650 °F.[18]) In practice, commercial SCR systems often meet control targets of over 90%.

Given that there are no fundamental physical obstacles to the NO_x control levels attainable with SCR, the control levels attained in practice are the result of system design. A prerequisite to high removal efficiencies is effective mixing of NO_x with a precisely determined amount of ammonia; this is readily achieved in current systems. The actual removal efficiency achieved thus is a function of the amount of catalyst installed and the amount of ammonia injected, so that the choice of control level is based on cost considerations. Control levels of 80-90% have proven cost-effective in many cases, although occasionally lower control levels have been specified as sufficient to meet permit limits.

In addition to high percentage reductions, very low controlled emissions levels also have proven cost-effective using SCR. Reductions in utility boiler emissions to the proposed OTAG-region 0.15 lb/MMBtu emission limit are readily achievable. Thus, at SCR systems at 19 coal-fired plants in the U.S. and Europe for which EPA has collected continuous emissions data, average NO_x emissions range from 0.04 lb/MMBtu to 0.17 lb/MMBtu, with NO_x removal efficiencies ranging from 54-94%.[19] (At some units, controlled emissions higher than 0.15 lb/MMBtu are sufficient to meet permit limits.)

For example, reductions of over 60% allow coal-fired boilers in New Jersey and Florida to meet 0.17 lb/MMBtu NO_x limits; mean hourly NO_x emissions from these boilers have been 0.13-0.16 lb/MMBtu, based on continuous emissions monitoring. At these coal-fired boilers, emissions have been decreasing over time as the firing system and SCR system operation is further optimized.[20]

SCR reductions of 60-65% at a coal-fired boiler in Virginia provide outlet emissions below 0.10 lb/MMBtu, even during severe load swings.[21] At a coal-fired cyclone boiler in New Hampshire, a retrofit SCR system provides a 65% emissions reduction from a 2.66 lb/MMBtu baseline to meet a 0.92 lb/MMBtu permit limit, and is expected to provide an 85-95% reduction to allow compliance with a lower 0.1-0.4 lb/MMBtu limit beginning in 1999.[22]

Large reductions are not limited to coal-fired units. On gas-fired utility boilers in California, SCR reduces emissions by more than 90% to well below 0.1 lb/MMBtu.[23]

On gas turbines, reductions of 90%, with guaranteed outlet emissions below 5 ppm, are common.[24] SCR has been used to reduce emissions from reciprocating engines by greater than 90%[24], with emissions from diesel engines reduced to well below 2 g/bhp-hr[25], and from dual fuel engines to below 0.5 g/bhp-hr.[26]

Is SCR Commercially Demonstrated in the U.S.?
SCR is installed on more than 300 sources in the U.S., including utility and industrial boilers, process heaters, gas turbines, internal combustion engines, chemical plants, and steel mills (see Appendix 2).

Retrofit SCR systems are in operation on 14 **gas-fired utility boilers** ranging in size from 147 to 750 MW in California. Commitments for several more units are pending. SCR systems are operating at 7 **coal-fired boilers**, including an existing cyclone boiler in New Hampshire, and new pulverized coal boilers in New Jersey (3 boilers), Florida (2), and Virginia (1). In addition to this significant experience, demonstrations at coal- and oil-fired units in the U.S.[14] and considerable experience abroad[27] suggest that SCR is a viable retrofit control technology for boilers used in electricity generation.

SCR is used to control NO_x emissions from more than 40 **industrial boilers and process heaters** in the U.S. These include both field-erected and small packaged boilers. Typical control levels on these units are 80-90%.

SCR has found growing use for the control of NO_x emissions from combined cycle **gas turbines**, with more than 100 systems installed in the U.S. since 1986.[28] Removal efficiencies of over 80% are common in this application,[29] and SCR has been used alone or in combination with other control technologies to achieve outlet NO_x levels below 5 ppm.[30] The development of the high-temperature SCR catalyst has allowed the use of SCR on simple cycle turbines.[17]

Another growing use of SCR is the control of NO_x emissions from stationary **reciprocating internal combustion engines**. SCR systems have been used to control emissions from more than 30 internal combustion engines burning natural gas, diesel fuel, and mixtures of these in the U.S., including engines on four marine vessels in California.[31] An SCR catalyst often is placed downstream of an oxidation catalyst to allow for simultaneous removal of NO_x and hydrocarbons and carbon monoxide.

SCR also has been used on other types of sources. At **nitric acid plants** throughout the U.S., SCR systems provide reductions often exceeding 90%.[32] SCR units have been installed on annealing furnaces at **steel mills** in Illinois, Indiana, and California, and at an electric arc furnace.

Can SCR Be Used With High-Sulfur and Other "Dirty" Fuels?
SCR systems are commercially proven on high-sulfur oil and medium-sulfur coal applications. Based on the widespread experience with SCR on coal-fired boilers abroad and successful demonstrations in the U.S., there is no technical impediment to the successful application of SCR systems to high-sulfur coal-firing facilities.

Concerns regarding the use of high-sulfur fuels center on the formation of ammonium bisulfate, a sticky substance which can mask the catalyst, plug air heaters, and corrode other downstream surfaces. Ammonium bisulfate is formed through the reaction of ammonia with SO_3, which in turn is formed in the furnace and through the oxidation of SO_2 by the SCR catalyst. By minimizing ammonia slip and suppressing sulfur dioxide oxidation across the catalyst, the amount of ammonium bisulfate formed is kept to a level which does not affect operation.

SCR has performed well on demonstrations on high-sulfur coal in the U.S., using systems designed for low ammonia slip and catalyst formulations designed to minimize oxidation of SO_2. For example, in testing sponsored by the U.S. Department of Energy, SCR catalysts made by a variety of U.S. and foreign manufacturers performed successfully on flue gas from a 75 MW tangentially fired boiler burning high-sulfur (3%) coal. Criteria for successful performance in this testing included 80% NO_x removal with less than 5 ppm ammonia slip and less than 0.75% SO_2 oxidation.[33]

Several of the catalysts in this test exceeded goals, with ammonia slip levels maintained below 1 ppm throughout the test[34]

SCR also performed well in a pilot plant study on a boiler burning a high-sulfur (1.5%) oil. The Electric Power Research Institute found that the study "successfully demonstrated long-term catalyst activity, direct injection of aqueous ammonia into the flue gas, and the ability of automatic control to operate effectively under extensive load-following conditions."[35]

In any case, the number of plants in the U.S. burning high-sulfur fuels is small. Only 6% of the power plants in the U.S. burn coal with a sulfur content exceeding 3%; the great majority (72%) burn coal with less than 2% sulfur, and over half (58%) burn coal with less than 1% sulfur. Worldwide, 4% of the SCR-equipped coal-fired boilers already burn coal with over 2% sulfur without incident. Further, several SCR-equipped units burn oils and other fuels containing very high levels (up to 5.4%) of sulfur. Firing such fuel places significantly greater demands on the SCR system than does firing coal, given the high levels of SO_3 and vanadium exiting the boiler.[36]

Concerns regarding other flue gas constituents, such as alkali metals and arsenic, center on catalyst deactivation. In wet bottom boilers which recirculate fly ash and thus concentrate poisons such as arsenic in the flue gas, initial experience in Europe suggested that catalyst lives might be uneconomically short. However, current catalysts are resistant to poisoning by arsenic and other contaminants,[37] so that catalyst life in wet bottom applications is now comparable to other applications.

Does SCR Cost Too Much?
No. The cost of controlling NO_x emissions with SCR is often less than $1000 per ton of NO_x removed.

SCR costs vary by the type of unit controlled. For **coal-fired utility boilers,** experience in the U.S. and abroad[38] suggests capital costs for retrofits on wall- and tangentially fired units of $50-70/kW, and for retrofits on cyclone and wet bottom wall-fired boilers of up to approximately $80/kW.

For example, the total capital cost of the SCR system at the 330 MW Merrimack 2 cyclone boiler was $56/kW.[39] Very high uncontrolled NO_x levels and a difficult retrofit should make the cost of this system higher than average. Based on detailed engineering studies, the costs for retrofitting SCR on six RACT-controlled pulverized coal boilers in the northeast range from $55/kW to $84/kW, with higher costs at smaller units and where crowding does not allow the installation of a lower-cost high-dust system. (See Appendix A).

Total cost per ton of NO_x removed (removal cost-effectiveness), which includes both capital recovery and operating costs, varies with the uncontrolled NO_x level of the source. Units with higher uncontrolled NO_x levels will have a lower removal cost per ton, because the capital expenditure spread over a greater number of tons removed. In general, costs are lower than expected, in part because of lower capital costs, but also because of improved catalysts and catalyst replacement strategies which lower annual catalyst purchase costs. In general, "post-RACT" control of wall- and tangentially fired boilers, with starting emissions of 0.5 lb/MMBtu or less, will be $800-1800/ton. On the other hand, "pre-RACT" control of these boilers will be less, at $600-1400/ton, because of higher starting emissions. For cyclone and wet-bottom units, which are expected to have even higher emissions and very limited scope for combustion controls, the cost-effectiveness will be $400-1000/ton.

At the Merrimack boiler, the SCR reduces emissions by 65% with a cost-effectiveness of $404/ton.[39] On the much cleaner RACT-controlled units detailed in Appendix A, detailed engineering estimates put retrofit SCR cost-effectiveness near $1000/ton.

Even on units with low starting emissions, SCR cost-effectiveness is reasonable. At a new coal-fired plant in Florida with boiler exit emissions of 0.32-0.35 lb/MMBtu, the SCR removes NO_x at a cost of approximately $1200/ton. The total capital cost of the SCR system at this plant was $47/kW.[40]

In Germany, where labor and materials costs are higher than in the U.S., retrofit costs of about $60/kW are common, with the cost of SCR systems on new coal-fired boilers often below $40/kW. Cost-effectiveness values in Germany have been in the $1000/ton range.[41]

Of equal importance to the capital cost and the cost-effectiveness is the operating cost. The operating cost of any pollution control technology must be low relative to the market price of goods produced to be economical. Fortunately, an independent power producer has determined that "the cost of SCR is insignificant to the cost of producing electricity"[42] Typical SCR operation and maintenance costs are below 1 mill/kWh (0.1¢/kWh), compared with typical consumer electricity rates of 70 mills/kWh (7¢/kWh).

For example, the SCR system at the coal-fired plant in Florida mentioned above has levelized operation and maintenance costs of 0.41 mills/kWh (0.041¢/kWh), and a total levelized cost (including capital recovery) of 0.98 mills/kWh (0.098¢/kWh), equivalent to less than 2% of typical consumer electricity prices. Equally important for electricity generation, the SCR system has no balance-of-plant operational impacts, with no requirements for increased staffing.[40]

For **oil- and gas-fired utility boilers**, SCR retrofit capital costs at several commercial installations have been $25-30/kW.[43] These units cost less to control than coal-fired boilers because lower NO_x emissions and lower particulate levels mean that less catalyst is needed, and a more compact reactor can be used.

Capital costs for installing SCR on new **industrial boilers** range from about $4000-6000 per million Btu per hour (MMBtu/hr) of heat input on small oil- and gas-fired units, to over $10,000/MMBtu/hr on larger coal-fired units. Based on these capital costs, the cost effective of SCR is approximately $1000-5000/ton of NO_x removed, depending upon the uncontrolled NO_x emissions and boiler size.[44]

For **gas turbines**, the cost of SCR is $30-100/kW, depending upon the size of the turbine. Removal costs range from less than $1000/ton to about $2500/ton for continuously operated turbines.[44]

Based on a report prepared for the gas industry, the cost of installing retrofit SCR on large **reciprocating internal combustion engines** is roughly $125/hp.[45] Compared with alternatives such as low emission combustion retrofits or replacement with electric engines, the cost of SCR thus is quite reasonable.

How Long Do SCR Catalysts Last?
Catalyst lives measured in years, together with optimized catalyst management programs, result in very low annual catalyst replacement costs.

SCR systems have been operating on power plants for more than 17 years.[46] While early projections assumed a one year life before catalyst replacement would be necessary, operating experience has shown these projections to be unduly pessimistic. At many installations, catalyst has not been replaced yet, so that it is impossible to determine catalyst life with any certainty.

Further, with proper catalyst management techniques, there is no need to replace all of the catalyst at once. For example, a vacant space for additional catalyst often is built into the SCR reactor. When NO_x conversion decreases or ammonia slip increases to the permit level, fresh catalyst may be placed into the vacant space, leaving the remainder of the catalyst intact. After that, periodic replacement of a fraction of the total catalyst inventory should be sufficient to maintain the desired activity.[47]

Management schemes such as this result in a greatly reduced need for replacement catalyst and a longer effective catalyst life.[48] The effective SCR catalyst life at coal-fired boilers is now expected to be about nine years.[49] For example, catalyst replacement schemes at units in New Jersey and Florida would result in the annual purchase of the equivalent of between 1/14 and 1/8 of the initial catalyst charge over a 15-year period, i.e., an effective life of 8 to 14 years.[50]

Given low catalyst replacement rates, SCR users must dispose of spent catalyst very infrequently. Most catalyst manufacturers offer a disposal service for spent catalyst. Typically, they either reactivate the catalyst for reuse, or recycle catalyst components for other uses. For example, in Japan, titanium dioxide from the catalyst is recycled for eventual use as a paint pigment.[51] Where the spent catalyst cannot be reactivated or recycled, it can be disposed of in approved landfills, as EPA has determined that spent catalyst is not a hazardous waste.[52]

Catalyst recycling, beyond minimizing disposal costs, can reduce total operating costs if recycled catalyst is used to replace spent catalyst. Depending on the cost of recycled catalyst relative to virgin catalyst, use of recycled catalyst can produce net present value savings in catalyst costs of 10-20% over the life of an SCR system.[53]

Can Ammonia Slip Be Controlled?
Ammonia "slip," the emission of unreacted ammonia from SCR systems, can be controlled to levels low enough that effects on plant operation, ash properties, and health will be insignificant.

Ammonia slip, caused by the incomplete reaction of injected ammonia, has been cited as a potential environmental and health hazard. Slip may be minimized by designing SCR systems to ensure good distribution and mixing of injected ammonia.

In practice, ammonia slip is a design parameter for catalyst sizing, just as is the level of NO_x reduction. Thus, the amount of catalyst used in a given system will be selected to meet permitted slip and outlet NO_x limits. In economical systems, nitrogen oxide removal efficiencies of up to 90 percent commonly are achieved with ammonia slip values below 5 ppm. In fact, slip has been controlled to below 2 ppm through proper design and use of sufficient catalyst; at these levels ammonia has no effect on fly ash disposability/sale.

In the U.S., permitted ammonia slip levels typically are in the 2-10 ppm ranges. Recent permits have called for ammonia slip levels of 5-10 ppm on gas turbines,[54] and 2-5 ppm on coal-fired boilers.[40,55] In actual practice, ammonia slip levels much lower than these are achieved. For example, at coal-fired boilers in New Jersey and Florida, SCR systems designed for 5 ppm ammonia slip have actual slip values of 0.16 ppm or below.[56] Only when the catalyst is near the end of its service life will slip values approach permitted levels.[12]

According to an EPA study, the ammonia slip at 14 coal-fired units with data available ranges from below 0.1 ppm to below 5 ppm. Seven of these units report slip below 1 ppm.[13] Any operational effects of ammonia slip on these units, in terms of air heater maintenance requirements and the ability to sell fly ash, are negligible.

Even permitted levels for ammonia slip in the U.S., which may not be reached during normal operation, are well below health and odor thresholds. For example, in permitting a pulverized coal cogeneration plant in New Jersey, state officials predicted that the project's 24-hour average and maximum one hour contributions to ambient ammonia levels would be 0.16 $\mu g/m^3$ and 1.7 $\mu g/m^3$, both well below the chronic health effect criterion of 34 $\mu g/m^3$.[57]

Can Ammonia Be Handled Safely?
Yes.

Concern over the handling of ammonia centers on the transportation and storage of a hazardous gas under pressure.[58] However, large quantities of ammonia already are used for a variety of applications with an excellent overall safety record.[59] (Last year, 39 billion pounds of ammonia were produced in the U.S.[60]) These applications include the manufacture of fertilizers and a variety of other chemicals, as well as refrigeration. With the proper controls, ammonia use is safe and routine.[61]

To avoid the risk of handling anhydrous ammonia, many current applications of SCR technology use aqueous ammonia, which is over 70% water, and thus avoid nearly all of the safety issues associated with anhydrous ammonia gas. Most utility SCR installations in California and several installations on coal-fired boilers in the east,[62] for example, use aqueous ammonia.

Can SCR Suppliers Meet the Current Compliance Needs of the U.S.?
Catalyst manufacturers and system suppliers have enough capacity to install SCR systems in time for Ozone Transport Region and phase II acid rain requirements in 1999 and 2000, and for Ozone Transport Assessment Group region requirements in 2002.

The approximately 15 suppliers of SCR technology worldwide, including some of the world's largest companies, estimate that they could supply in two years *all* the SCR control systems likely to result from current U.S. regulations with capacity to spare. The heart of an SCR system is the catalyst, and if extra catalyst capacity were needed, at least three to four of the largest SCR suppliers could *double* their capacity within one year.

In fact, significant overcapacity exists as a result of the maturing of SCR markets abroad. Companies that supplied these systems are still in business and looking to the U.S. for future markets. In addition, U.S. firms have entered the market over the past ten years in anticipation of a NO_x reduction program in the U.S.

A further concern, that the process of installing SCR systems on large numbers of utility boilers would affect the reliability of U.S. power producers, also is groundless. Most of the construction work required to install an SCR system may be done while the boiler is operating. Connection of the SCR reactor to the boiler typically is accomplished during a regularly scheduled maintenance outage, and so should affect generating capacity minimally, if at all.

Are Low-NO_x Burners and Combustors Preferable to SCR?
While low-NO_x burners and low-NO_x combustors are often appropriate tools for controlling NO_x emissions, they have limited NO_x removal capabilities and may have hidden costs.

In many cases, "pollution prevention" approaches such as the use of low-NO_x burners, overfire air, and low-NO_x combustors are the most cost-effective way to control emissions. Unfortunately, low-NO_x combustion technologies are often unable to meet the required emission limits. For example, low-NO_x combustors are generally unable to reduce gas turbine NO_x emissions below 15 ppm to the 3-9 ppm limits called for by regulators.[54]

Low-NO_x technologies also may be inappropriate choices when emission limits are likely to change over time. Incurring the costs of two retrofits by installing low-NO_x burners followed by a second NO_x control technology a short time later clearly is a questionable strategy, given the availability of a technology like SCR which allows cost-effective compliance with a broad range of emission limits.

For some units, such as cyclone and other wet-bottom boilers, low-NO_x technologies are available, but these may change operating conditions in unacceptable ways. Low-NO_x burners also may cause significant operating problems when retrofit in existing boilers. These problems may include localized furnace and watertube corrosion, lower boiler efficiency, and increased particulate emissions.[63]

For example, one power producer using both low-NO_x burners and SCR found that tuning the burners to reduce NO_x emissions increased fly ash loss-on-ignition levels and decreased boiler efficiency. That producer is now retuning the burners for maximum boiler efficiency and minimum loss-on-ignition, and will use the SCR system to remove any additional NO_x. Beyond lower fuel use, the producer expects ancillary savings from reductions in burner maintenance requirements and boiler corrosion.[42]

Of course, in some cases, the most cost-effective approach may be a combination of low-NO_x burners or combustors and SCR.

What Are Some Recent Developments in SCR?
SCR suppliers are continuing to reduce costs further through improvements in catalyst technology and system design, and to exploit the capabilities of SCR catalysts for the removal of multiple pollutants.

Catalyst manufacturers have continued to improve catalysts and extend SCR catalyst capabilities. Current SCR catalysts are more resistant to poisoning and erosion than their forebears, and thus have longer lives.[64] Catalysts for high-temperature operation, e.g., in simple cycle turbines, are finding expanded use.[54] Catalysts which reduce dioxin and furan emissions, as well as NO_x emissions, are being installed on units such as incinerators.

SCR suppliers also are working to expand the capabilities and reduce the cost of SCR. Use of sophisticated flow modeling allows the design of systems with very uniform gas flows and NH_3/NO_x ratios, thus reducing required catalyst volumes and minimizing ammonia slip.[65]

Suppliers also have developed hybrid selective non-catalytic reduction (SNCR)-SCR systems. These hybrids rely on reaction with urea or ammonia in the boiler to destroy a portion of the NO_x, followed by further reaction in a reduced-size catalyst reactor to destroy most of the remaining NO_x. The hybrids thus provide high removal efficiencies and low ammonia slip, but with reduced capital costs.

Finally, suppliers are using financial innovations to help users of SCR. One potential impediment to the installation of an SCR system is the requirement that the user commit capital funds. Suppliers are now offering to provide SCR through a build-own-operate-maintain (BOOM) program. In BOOM, the supplier finances, owns, and operates the SCR system, thus avoiding a capital expenditure by the user. The user of the SCR system merely pays an annual fee for NO_x control, thus converting a capital cost to an operating cost.[66]

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APPENDIX 1: Estimated Costs for SCR Retrofits on Coal-Fired Boilers

The following tables contain estimates of the cost of installing and operating retrofit SCR systems on six actual pulverized coal boilers. These boilers are already controlled to RACT levels; SCR would allow compliance with anticipated tighter Ozone Transport Region emission limits, and also would likely allow the generation of NO_x credits for sale.

The estimates are based on detailed engineering studies (3-6 months per utility) done for three utilities in the northeast. Because the engineering studies make no allowance for competitive bids on individual pieces of equipment, the all-in costs to utilities are likely to be lower than the estimates.

Major cost categories included in the estimates are demolition (existing ductwork, inlet air duct, steel), boiler modifications, fan modifications and ductwork, supplemental support for existing structural steel, fan motor and rotor modifications, electrical system modifications, SCR catalyst and reactor housing, sootblowers, ammonia storage and vaporization/injection systems, monitoring and control systems, and installation. All systems include new or modified induced draft fans to account for the higher pressure drop, and include sootblowers for each layer of catalyst. Electrical system modifications are included on all units on the assumption that all additional electrical auxiliary loads must have a new breaker and wiring. Additional transformers are not included.

For units ranging in size from 190 MW to 570 MW, the all-in capital costs for these SCR systems will be $55-84/kW. The $84/kW figure is for a tail-end SCR system on a boiler with no room for a more customary (and less expensive) high-dust system, and thus is likely to be among the highest costs expected for retrofit SCR.

Operating costs are based on typical catalyst management strategies, calling for the presence of a spare layer for future catalyst addition, followed by periodic replacement of a fraction of the total catalyst charge, and on knowledge of fixed operating and maintenance costs for SCR systems in the U.S. and Germany. Energy costs include the additional horsepower required by the induced fan due to the pressure drop across the SCR system.

Expected SCR total costs for the indicated boilers are $800-1200/ton. Assuming lower capacity factors or lower removal efficiencies would increase the upper end of the expected cost range to near $1800/ton.

Note that because these boilers already are controlled to RACT levels of 0.38-0.5 lb/MMBtu, the SCR cost-effectiveness values are relatively high. On uncontrolled ("pre-RACT") dry bottom boilers, SCR costs should be in the range of $600-1400/ton.

On the indicated boilers, SCR would increase consumer electric rates by 2-4%.

Table A1. Estimated Costs of Retrofit SCR Systems on RACT-Controlled Dry Bottom Coal-fired Boilers (1996 Dollars)

	Unit	A	B	C	D	E	F
Size, MW		570	490	190	300	560	250
Capacity Factor, %		80%	80%	82%	71%	70%	70%
Reactor Location		High Dust	Tail-end	High Dust	High Dust	High Dust	High Dust
Retrofit Difficulty (1 = low, 5 = high)		4	3	4	5	3	4
NO_x emissions, lb/MMBtu		0.43	0.5	0.5	0.45	0.53	0.38
NO_x Reduction, %		85%	85%	85%	85%	85%	85%
Capital Costs	Equipment	$13,787,000	$18,216,000	$6,925,000	$9,269,000	$15,277,000	$8,324,000
	Installation	$6,805,000	$8,890,000	$2,799,000	$4,860,000	$6,941,000	$2,720,000
	Total Direct	$20,592,000	$27,106,000	$9,724,000	$14,129,000	$22,218,000	$11,044,000
	Contingency (20%)	$4,118,400	$5,421,200	$1,944,800	$2,825,800	$4,443,600	$2,208,800
	Escalation (1.5 yrs./4%)	$1,247,794	$1,642,517	$589,236	$856,162	$1,346,323	$669,223
	Indirects (15%)	$3,893,729	$5,125,458	$1,838,705	$2,671,644	$4,201,188	$2,088,303
	AFUDC (0.5 yrs./9%)	$1,314,400	$1,730,192	$620,689	$901,862	$1,418,188	$704,945
	Total	$31,166,323	$41,025,366	$14,717,430	$21,384,468	$33,627,300	$16,715,271
Operating Costs	Catalyst Replacement	$803,000	$364,000	$196,000	$300,000	$572,000	$254,167
	Ammonia	$669,000	$847,000	$282,000	$324,000	$692,000	$219,167
	Energy	$263,000	$852,000	$100,000	$140,000	$284,000	$156,667
	Natural Gas	$0	$3,231,000	$0	$0	$0	$0
	Maintenance Material	$57,000	$148,000	$26,000	$30,000	$43,000	$38,333
	Personnel	$60,000	$60,000	$78,000	$78,000	$78,000	$40,000
	Ammonia Testing	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
	Total	$1,877,000	$5,527,000	$707,000	$897,000	$1,694,000	$733,333
Capital Recovery (0.12)		$3,739,959	$4,923,044	$1,766,092	$2,566,136	$4,035,276	$2,005,833
Total Annual Cost		$5,616,959	$10,450,044	$2,473,092	$3,463,136	$5,729,276	$2,739,166
NO_x Reduction, ton/yr		6,900	8,700	2,900	3,340	7,128	2,706
NO_x Reduction Cost, $/ton		$814	$1,201	$853	$1,037	$804	$1,012
Capital Cost, $/kW		$55	$84	$77	$71	$60	$67
Total Annual Cost, ¢/kWh		0.141	0.304	0.181	0.186	0.167	0.179
Change in Consumer Electric Rates, %		1.76%	3.80%	2.27%	2.32%	2.09%	2.23%

Table A2. Details of Retrofit Cost Estimate for unit "F"	
Capital Costs	
Catalyst	$2,420,000
Ammonia Storage	$1,146,000
Ammonia Vaporization/Injection	$707,000
Electrical System	$535,000
Controls	$496,000
Ductwork/Reactor	$1,370,000
Sootblowers	$369,000
Structural Steel	$618,000
Foundations	$119,000
Insulation/Lagging	$1,143,000
ID Fan Modifications	$1,149,000
Piping	$606,000
Freight	$40,000
Demolition	$105,000
Start-up	$30,000
Training	$26,000
DCS Modifications	$115,000
Performance Testing	$50,000
Subtotal	$11,044,000
Contingency (20%)	$2,208,800
Subtotal	$13,252,800
Escalation (4%/1.5 yrs)	$669,223
Indirects (15%)	$2,088,303
Interest During Construction (9%)	$704,945
Total 1997 Capital Cost	$16,715,271
Total 1997 Capital Cost, $/kW	$67
Levelized Annual Costs	
Fixed Charges on Capital(14%)	$2,340,138
Energy	$188,000
Ammonia	$263,000
Catalyst Replacement	$305,000
Operating Personnel	$48,000
Maintenance cost	$46,000
Ammonia Testing	$30,000
Total Levelized Annual Cost, $/yr.	$3,220,138
Total Levelized Annual Cost, mills/kWh	2.13
Basis:	
Escalation:	70.0%
PWDR:	40 mills/kWh
FCR:	$250/ton

APPENDIX 2: Partial List of U.S. Applications of SCR

PLANT (1),(2)		SIZE (3)	FUEL (4)	REDUCTION (%) (5)	START OF OPERATION
Utility Boilers					
Los Angeles Department of Water and Power Haynes Station, Long Beach, California	Unit 1	230 MW	NG	92	1993
	Unit 2	230 MW	NG	92	1994
	Unit 5	330 MW	NG	94	1993
	Unit 6	330 MW	NG	94	1997 (6)
Southern California Edison Redondo Beach, California	Unit 7	480 MW	NG	87	1994
	Unit 8	480 MW	NG	87	1993
Southern California Edison Alamitos, California	Unit 3	320 MW	NG	90	(6)
	Unit 4	320 MW	NG	90	(6)
	Unit 5	480 MW	NG	87	1994
	Unit 6	480 MW	NG	87	1993
Southern California Edison Ormund Beach, California	Unit 1	750 MW	NG	93	1994
	Unit 2	750 MW	NG	93	1993
Southern California Edison El Segundo, California	Unit 3	335 MW	NG	90	(6)
	Unit 4	335 MW	NG	90	1994
Southern California Edison Etiwanda, California	Unit 3	320 MW	NG	90	(6)
	Unit 4	320 MW	NG	90	(6)
Southern California Edison Mandalay, California	Unit 1	230 MW	NG		1996
	Unit 2	230 MW	NG		1996
Pacific Gas & Electric Pittsburg, California	Unit 5	325 MW	oil		(6)
	Unit 6	325 MW	oil		1996
San Diego Gas & Electric South Bay, California	Unit 1	147 MW	NG/oil	90	1996
	Unit 2	147 MW	NG/oil		(6)
Orlando Utilities Commission Stanton	Unit 2	460 MW	coal	47	1996

PLANT (1),(2)	SIZE (3)	FUEL (4)	REDUCTION (%) (5)	START OF OPERATION
U.S. Generating Chambers Works, Carneys Point, New Jersey	2X140 MW	coal	63	1994
U.S. Generating Keystone, New Jersey	200 MW	coal	63	1994
U.S. Generating Indiantown, Florida	320 MW	coal	67	1995
Southern Energy Inc. King George County, Virginia	245 MW	coal	53	1996
Public Service of New Hampshire Merrimack Station, Bow, New Hampshire Unit 2	330	coal	65	1995
Industrial Boilers				
Westinghouse Electric Corporation Sunnyvale, California	360,000 lb/hr	NG	75	1989
Operational Energy Corporation Ontario, California	210,000 lb/hr	NG	82.5	1990
Kal Kan Vernon, California	69,000 lb/hr	NG	88	1991
	145,000 lb/hr			1993
Lockhead Advanced Development Corp. Palmdale, California	90 MMBtu/hr	NG	<9 ppmvd	1993
TOSCO Avon Refinery	178,000 lb/hr	refinery gas	90	1993
Shell	815,000 lb/hr			1994
Ultramar	200,000 lb/hr			1994
Sauder Woodworking Ohio	2@60 MMBtu/hr	wood waste	80	1994
Refinery California	17,100 scfm	refinery gas		1994
Crockett Package Boilers (3 units)	330,000 lb/hr			1995
Gaylord Container	382,000 lb/hr			1995
Process Heaters				
Texaco Los Angeles, California	12,000 scfm	NG	82	1990
Mobil Oil Company Torrance, California No.1	19,000 scfm	NG	90	1990
Mobil Oil Company Torrance, California No.2	19,000 scfm	NG	90	1990

PLANT (1),(2)	SIZE (3)	FUEL (4)	REDUCTION (%) (5)	START OF OPERATION
Mobil Oil Company Torrance, California No.3	213,000 scfm	NG	87	1990
Fletcher Oil & Refining Company Carson, California	9650 scfm		83	1991
Ultramar Refining Wilmington, California	24,300 scfm		94	1992
Ashland Petroleum St. Paul, Minnesota	22,000 scfm		90	1993
Arco Los Angeles, California	51,000 scfm	RG	8 ppm	1994
California Refinery Hydrogen Reformer	82,000 scfm	RG	90	1994
Powerine Fired Heater	125,000 lb/hr			1994
Shell Delayed Coker (2 units)	112,000 lb/hr			1995
Shell Hydrogen Reformer	815,000 lb/hr			1995
Oxy Mar	330,000 lb/hr			1996
Exxon Benicia	68,250 scfm	RG	10 ppm	1996
Ultramar, Inc.	22,600 scfm	RG	5 ppm	1996
Gas Turbines				
Willamette Industries Oxnard, California	21 MW	NG	80	1986
Monarch Cogeneration Taft, California	8 MW	NG	85	1986
University Energy Taft, California	37 MW	NG	90	1986
Union Oil Rodeo, California	Westinghouse 191	RG/NG/diesel	46	1987
Pomona Cogeneration Partners Pomona, California	3.5 MW		< 9 ppm	1987
ARCO Watson, California	80 MW	NG	90	1987
Chevron El Segundo, California	37 MW	NG	90	1988
Union Carbide Linde Wilmington, California	21 MW	NG	90	1988
American Energy Systems Placerita, California	TA-8	NG	83	1988
Cogen Tech. Bayonne, New Jersey	37 MW	NG	80	1988

PLANT (1),(2)	SIZE (3)	FUEL (4)	REDUCTION (%) (5)	START OF OPERATION
Cogen Tech. Bayonne, New Jersey	37 MW	NG	80	1988
Cogen Tech. Bayonne, New Jersey	37 MW	NG	80	1988
Chevron El Segundo, California	37 MW	NG	90	1988
Los Angeles County Civic Center Los Angeles, California	21 MW	NG	79	1988
Los Angeles County Pitchess, California	21 MW	NG	79	1988
ARCO Watson, California	80 MW	NG	90	1988
Amercian Energy Systems Placerita, California	TA-8	NG	82	1988
ARCO Watson, California	80 MW	NG	90	1988
ARCO Watson, California	80 MW	NG	90	1988
Simpson Paper Company/Ripon Cogeneration	33 MW			1988
Corona Cogeneration	33 MW			1988
Navy California	37 MW	NG	80	1989
Basic American Foods	80 MW			1989
Navy California	21 MW	NG	80	1989
Proctor & Gamble Oxnard, California	33 MW	NG	80	1989
Mission Energy Harbor Cogeneration	80 MW			1989
Navy California	33 MW	NG	80	1989
NEPCO Bakersfield, California	21 MW	NG	80	1989
LFC Power Systems Corporation Yuba City, California	33 MW	NG	86	1989
Shell Oil Company Kern River Cogeneration	21 MW			1989
O'Brien Califonia Cogen for Stewart & Stevenson Artesia, California	21 MW	NG	82	1989

PLANT (1),(2)	SIZE (3)	FUEL (4)	REDUCTION (%) (5)	START OF OPERATION
Texaco Oil Company Mid-Set Cogeneration	37 MW			1989
Calpine Watsonville Cogeneration	21 MW			1990
Altresco/Pittsfield	37 MW			1990
Altresco/Pittsfield	37 MW			1990
Altresco/Pittsfield	37 MW			1990
Ice Haus II California	33 MW	NG	80	1990
Exxon Santa Ynez, California	37 MW	NG	90	1990
Richmond, Virginia	83 MW	NG/oil	80	1990
Richmond, Virginia	83 MW	NG/oil	80	1990
Dexcel California	21 MW	NG	84	1990
Salinas, California	33 MW	NG	65	1990
Tenneco Placerita Canyon, California	21 MW	NG	79	1990
Tenneco Placerita Canyon, California	21 MW	NG	79	1990
Calpine Agnews Cogeneration	21 MW			1990
Parlin, New Jersey	37 MW	NG	68	1990
Parlin, New Jersey	37 MW	NG	68	1990
UNOCAL Science & Technology Center Brea, California	4.0 MW		< 9 ppm	1990
U.S. Borax Mojave Cogeneration	MW-251			1990
Oxnard Incorporated Sithe Energies	33 MW			1990
Newark, New Jersey	37 MW	NG	53	1990
Ocean State Burrillville, Rhode Island	80 MW	NG/oil	79	1990
Ocean State Burrillville, Rhode Island	80 MW	NG/oil	79	1990
Pawtucket Power Associates	37 MW			1991

PLANT (1),(2)	SIZE (3)	FUEL (4)	REDUCTION (%) (5)	START OF OPERATION
City of Anaheim Anaheim, California	33 MW	NG	76	1991
Mission Energy Coalinga Cogeneration	37 MW			1991
Saguaro/Mission Energy Henderson Cogeneration	37 MW			1991
Saguaro/Mission Energy Henderson Cogeneration	37 MW			1991
Linden Cogeneration No. 1	80 MW			1992
Linden Cogeneration No. 2	80 MW			1992
Linden Cogeneration No. 3	80 MW			1992
Linden Cogeneration No. 4	80 MW			1992
Linden Cogeneration No. 5	80 MW			1992
Ocean State Burrillville, Rhode Island	80 MW	NG/oil	79	1992
Ocean State Burrillville, Rhode Island	80 MW	NG/oil	79	1992
Imperial Irrigation District California	82 MW			1992
Chevron Richmond, California	37 MW	NG	90	1992
Chevron Richmond, California	49 MW	NG	90	1992
Encogen Northwest	37 MW			1992
Encogen Northwest	37 MW			1992
March Point Cogeneration Facilities Anacortes 3	PG6541			1992
Mission Energy Sargent Canyon Cogeneration	37 MW			1992
Mission Energy Salinas River Cogeneration	37 MW			1992
Sanger Cogeneration Dynamis Cogeneration	MW-251			1992
Doswell Combined Cycle Facility	141 MW			1992
Doswell Combined Cycle Facility	141 MW			1992
Doswell Combined Cycle Facility	141 MW			1992
Doswell Combined Cycle Facility	141 MW			1992

PLANT (1),(2)	SIZE (3)	FUEL (4)	REDUCTION (%) (5)	START OF OPERATION
Alcoa Cogeneration	47 MW			1992
Pratt & Whitney Aircraft	21 MW			1992
B.F. Goodrich	80 MW			1992
Dartmouth Cogeneration	37 MW			1992
Southern California Gas Company Kern County, California	3.8 MW	NG	< 5 ppm	1993
Southern California Gas Company Kern County, California	3.8 MW	NG	< 5 ppm	1993
Southern California Gas Company Kern County, California	3.8 MW	NG	< 5 ppm	1993
Big Three Industries	37 MW			1993
Olean	37 MW			1993
Lakewood	80 MW			1993
Ogdensburg	21 MW			1993
Ogdensburg	41 MW			1993
Lone Star Encogen	37 MW			1993
Lone Star Encogen	37 MW			1993
Lone Star Encogen	37 MW			1993
U.S. Generating Company East Syracuse, New York	39 MW	NG	< 9 ppm	1993
U.S. Generating Company East Syracuse, New York	39 MW	NG	< 9 ppm	1993
UCLA Los Angeles, California	13 MW			1993
UCLA Los Angeles, California	13 MW			1993
Los Angeles Department of Water and Power Harbor 10A	80 MW			1993
Los Angeles Department of Water and Power Harbor 10B	80 MW			1993
Masspower	PG7111EA			1993
Masspower	PG7111EA			1993
Mobil Oil Beaumont, Texas	PG6541B			1993

PLANT (1),(2)	SIZE (3)	FUEL (4)	REDUCTION (%) (5)	START OF OPERATION
Onondoga	21 MW			1993
Onondoga	33 MW			1993
Gordonsville	84 MW			1993
Gordonsville	84 MW			1993
Saranac	80 MW			1994
Saranac	80 MW			1994
NEPCO Vinland Energy Facility	42 MW			1994
Allegheny	34MW			1994
Tenaska	80 MW			1994
Tenaska	80 MW			1994
Destec Energy	33 MW			1994
Corinth Energy Center	80 MW			1994
Olean Cogeneration	38 MW			1994
Anacortes II	37 MW			1994
Anacortes II	37 MW			1994
March Point Cogeneration Facilities Anacortes 1, 2	PG6541			1994
March Point Cogeneration Facilities Anacortes 1, 2	PG6541			1994
New York Power Authority Holtsville, New York	105 MW			1994
Selkirk Cogeneration Facility	80 MW			1994
Selkirk Cogeneration Facility	80 MW			1994
Sithe Energies USA, Inc. Independence	80 MW			1994
Sithe Energies USA, Inc. Independence	80 MW			1994
Sithe Energies USA, Inc. Independence	80 MW			1994
Sithe Energies USA, Inc. Independence	80 MW			1994
LG&E Westmoreland Rensselaer Cogeneration	52 MW			1994
WEPCO/Kimberly	49 MW			1994

PLANT (1),(2)	SIZE (3)	FUEL (4)	REDUCTION (%) (5)	START OF OPERATION
Crockett Cogeneration	80 MW			1995
Bristol-Myers Squibb	33,800 scfm	NG/kerosene	15 ppm	1995
City of Redding Redding, California	25 MW	NG-LPG backup	9 ppm	1995
City of Redding Redding, California	25 MW	NG-LPG backup	9 ppm	1995
City of Redding Redding, California	25 MW	NG-LPG backup	9 ppm	1995
EEA I	80 MW			1995
EEA II	80 MW			1995
EEA III	80 MW			1995
Carson Energy Ice Gen. No. 1	41 MW			1995
Carson Energy Ice Gen. No. 2 (simple cycle)	41 MW			1995
Mobil San Ardo	Solar			1995
Brooklyn Navy Yard	105 MW			1995
Brooklyn Navy Yard	105 MW			1995
Anderson Lithograph	Solar			1995
Naval Petroleum	21 MW			1995
Naval Petroleum	21 MW			1995
New England Power Manchester, New Hampshire	105 MW			1995
New England Power Manchester, New Hampshire	105 MW			1995
New England Power Manchester, New Hampshire	105 MW			1995
Willamette Industries Albany Mill	62 MW	NG	80	1995
LS Power Cottage Grove	119 MW			1996
Hermiston Cogeneration	80 MW			1996
Hermiston Cogeneration	80 MW			1996
Clayburne	119 MW			1996

PLANT (1),(2)	SIZE (3)	FUEL (4)	REDUCTION (%) (5)	START OF OPERATION
Shell Martinez, California	37 MW			1996
Shell Martinez, California	37 MW			1996
Sacramento Municipal Utility District	41 MW			1996
Sacramento Municipal Utility District	41 MW			1996
Blue Mountain Cogen	119 MW			1996
Iowa Electric	21 MW			1996
LS Power Whitewater	119 MW			1996
University of California San Francisco, California	4.5 MW	NG/diesel	92	1996
Ocean State Power (4 units)	80 MW			1996-1997
TIC North American Chemical	33 MW			1997
Chesapeake Paper Vogt	37 MW			1997
Cogentrix		NG/oil	80	1997
Reciprocating Engines				
Citizen Utilities Co. Kauai, Hawaii	7.9 MW	diesel		1991
Natural Gas Pipeline Compressor Station Southern California	3@8800 scfm	NG	< 30 ppm	1993
Village of Rockville Center Long Island, New York	8710 hp	DF-diesel	80	1995
Plymouth State Cogeneration New Hampshire	1600 hp	#6 fuel oil	95	1993
U.S. Water Treatment Plant	2@1100 hp	diesel	90	1994
Puerto Rico Cogeneration Plant	5@1384 kW	diesel	95	1994
Philadelphia Water Department Southwest Philadelphia	10@1150 hp	diesel	80	1993
Philadelphia Water Department Northeast Philadelphia	7@2340 hp	diesel	80	1993
Pfizer, Inc.	4@1384 kW	#2 diesel	95	1997
Nitric Acid Plants				
First Chemical Corp. Pascagoula, Mississippi	225 tons/day		>80	1991

PLANT (1),(2)	SIZE (3)	FUEL (4)	REDUCTION (%) (5)	START OF OPERATION
E.I. DuPont de Nemours Orange, Texas	500 tons/day		>75	1986
E.I. DuPont de Nemours Victoria, Texas				
Arcadian Fertilizer Lima, Ohio	245 tons/day		>90	1992
Radford Munitions	20,000 lb/hr			1995
Farmland Industries Fort Dodge, Kansas	476 tons/day		>93	1997
CF Industries Donaldsonville, Louisiana	870 tons/day		>87	1997
Apache Nitrogen Products	13,000 scfm		97	1994
Steel Mill Annealing Furnaces				
Drever/Bethlehem Steel Burns Harbor, Indiana	209,000 lb/hr	NG	90	1992
Drever/National Steel Granite City, Illinois	140,000 lb/hr	NG	90	1995
Drever/AK Steel Rockport, Indiana	280,000 lb/hr	NG	85	1998
U.S.S.-POSCO Industries Pittsburg, California	22,000 scfm		90+	1988
Steel Mill Electric Arc Furnace				
Beta Steel	85,980 scfm		96	1996

(1) All units listed are commercial installations, including units in the design and installation phases. Plants listed more than once have multiple SCR systems.
(2) Plants may not be named for reasons of confidentiality.
(3) Units of size refer to electrical output if MW, engine output if hp, steam production if lb/hr, heat input if MMBtu/hr, or flue gas flow if scfm.
(4) NG, natural gas; RG, refinery gas; DF, dual fuel.
(5) NO_x reduction values are design values, and do not represent the limit of the technology. Where a ppm value is shown, this represents a design emission limit.
(6) Contract awarded, but installation delayed.