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WHITE PAPER

SELECTIVE NON-CATALYTIC REDUCTION (SNCR) FOR CONTROLLING NO_X EMISSIONS

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SNCR COMMITTEE

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ICAC

The Institute of Clean Air Companies (ICAC) is the national association of companies that supply stationary source air pollution monitoring and control systems, equipment, and services. It was formed in 1960 as a nonprofit corporation 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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PURPOSE

To comply with federal, state, and local acid rain and ozone non-attainment rules, both regulators and regulated industry seek nitrogen oxide (NO_x) controls which offer the greatest reliability and effectiveness at the least cost. One such NO_x control technology is selective non-catalytic reduction (SNCR). Although SNCR will not be universally applicable, or always the most cost effective control strategy, in many cases it will meet the dual requirements of high performance and low cost, and so should be considered by affected sources and permitting authorities. To date, SNCR technology has been installed on 90 units in the power generation industry and on more than 300 industrial units (see Appendix 1 for a partial installation list).

The SNCR Committee of the Institute of Clean Air Companies, Inc. (ICAC) prepared this white paper to educate all interested parties on the capabilities, limitations, and cost of SNCR.

ICAC is the nonprofit national association of companies which supply stationary source air pollution monitoring and control systems, equipment, and services. Its members include suppliers of SNCR systems, and of competing NO_x control technologies.

EXECUTIVE SUMMARY

Selective non-catalytic reduction (SNCR) is a chemical process for removing nitrogen oxides (NO_x) from flue gas. In the SNCR process, a reagent, typically urea or anhydrous gaseous ammonia, is injected into the hot flue gas, and reacts with the NO_x, converting it to nitrogen gas and water vapor. No catalyst is required for this process. Instead, it is driven by the high temperatures normally found in combustion sources.

SNCR performance depends on factors specific to each source, including flue gas temperature, available residence time for the reagent and flue gas to mix and react, amount of reagent injected, reagent distribution, uncontrolled NO_x level, and CO and O_2 concentrations. However, reductions in emissions of 25-75 % are common. Using appropriately designed SNCR systems, these levels of control are not accompanied by excessive emissions of unreacted ammonia (ammonia slip) or of other pollutants, particularly using recent design upgrades demonstrated on commercial systems. Further, SNCR does not generate any solid or liquid wastes.

SNCR also may be combined with low NO_x burners (LNB), over-fired air (OFA), neural networks, rich reagent injection (RRI), and selective catalytic reduction (SCR) systems or with gas reburn technologies to provide deeper emissions reductions for moderate capital investment. A combined SNCR/SCR system can be designed to use substantially less catalyst (typically installed “in-duct”) than a conventional SCR, allowing higher overall NO_x reduction than SNCR alone and lower ammonia slip, but with a relatively moderate increase in capital cost. A combined SNCR/SCR system can also be designed, particularly in the case of moderate duty boilers, to have a SNCR/SCR system to perform equivalently to a full SCR system to smoothen NO_x reduction at lower loads.

SNCR is a proven and reliable technology. SNCR was first applied commercially in 1974, and significant advances in understanding the chemistry of the SNCR process since then have led to improved NO_x removal capabilities as well as better ammonia slip control. As a result, approximately 400 SNCR systems have been installed worldwide. Applications include utility and industrial boilers, process heaters, municipal waste combustors, and other combustion sources.

SNCR is not a capital-intensive technology. Low capital costs, ranging from $5-20/kWe on power generation units, make SNCR particularly suitable for use on lower capacity factor units, on units with short remaining service lives and for seasonal control. SNCR also is well suited for NO_x “trimming” and for use in combination with other NO_x reduction technologies. SNCR can provide 10-25 % reductions in power generation boiler NO_x emissions for total costs below 1 mill/kWh. Removal cost effectiveness values for SNCR center around $1,500-2,500 per ton of NO_x removed.

The performance and cost of SNCR make this technology attractive for export, including to developing and former Soviet Union countries.

SELECTIVE NON-CATALYTIC REDUCTION (SNCR) FOR CONTROLLING NO_X EMISSIONS

What is SNCR?

Selective non-catalytic reduction (SNCR) is a chemical process that changes nitrogen oxides (NO_x) into molecular nitrogen (N_2), carbon dioxide (CO_2) (if urea is used), and water vapor. A reducing agent, typically anhydrous gaseous ammonia or liquid urea, is injected into the combustion/process gases. At suitably high temperatures (1,600 - 2,100 F)1[1], the desired chemical reactions occur.

Conceptually, the SNCR process is quite simple. A gaseous or aqueous reagent of a selected nitrogenous compound is injected into, and mixed with, the hot flue gas in the proper temperature range. The reagent then, without a catalyst, reacts with the NO_x in the gas stream, converting it to harmless nitrogen gas, carbon dioxide gas (if urea is injected), and water vapor. SNCR is “selective” in that the reagent reacts primarily with NO_x,. A schematic depicting the SNCR process is shown in Figure 1.[2]

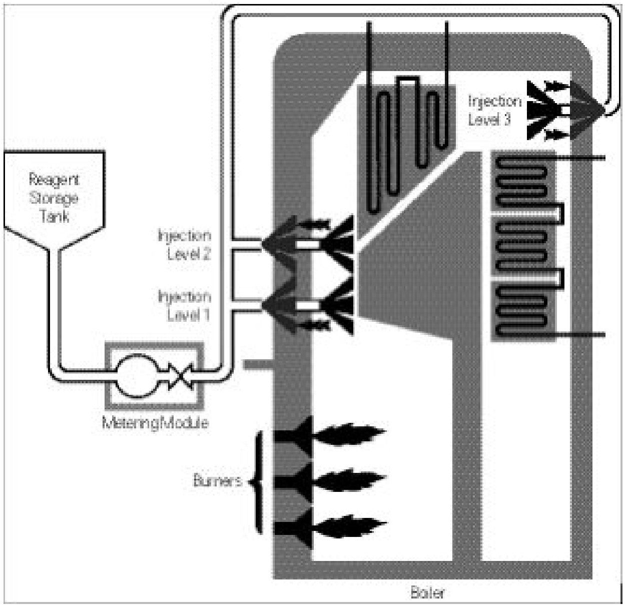

Figure 1. **SNCR Process Schematic.** *Source:* Fuel Tech

No solid or liquid wastes are created in the SNCR process.

While either urea or ammonia can be used as the reagent, for most commercial SNCR systems, urea has become the prevalent reagent used. Urea is injected as an aqueous solution while ammonia is typically injected in either its gaseous or anhydrous form using carrier air as a dilutive and support medium.

The principal components of the SNCR system are the reagent storage and injection system, which includes tanks, pumps, injectors, distribution modules, and associated controls. Given the simplicity of these components, installation of SNCR is easy relative to the installation of other NO_x control technologies. SNCR retrofits typically do not require extended source shutdowns.

How much NO_x can SNCR remove?

While SNCR performance is specific to each unique application, NO_x reduction levels ranging from 30 % to more than 75 % have been reported.

Temperature, residence time, reagent injection rate, reagent distribution in the flue gas, uncontrolled NO_x level, and CO and O_2 concentrations are important in determining the effectiveness of SNCR.[3] In general, if NO_x and reagent are in contact at the proper temperature for a long enough time, then SNCR will be successful at reducing the NO_x level.

SNCR is most effective within a specified temperature range or window. A typical removal effectiveness curve, as a function of temperature within this window, is shown in Figure 2. At temperatures below the window, reaction rates are extremely low, so that little or no NO_x reduction occurs. As the temperature within the window increases, the NO_x removal efficiency increases because reaction rates increase with temperature. Residence time typically is the limiting factor for NO_x reduction in this range. At the plateau, reaction rates are optimal for NO_x reduction. A temperature variation in this range will have only a small effect on NO_x reduction.

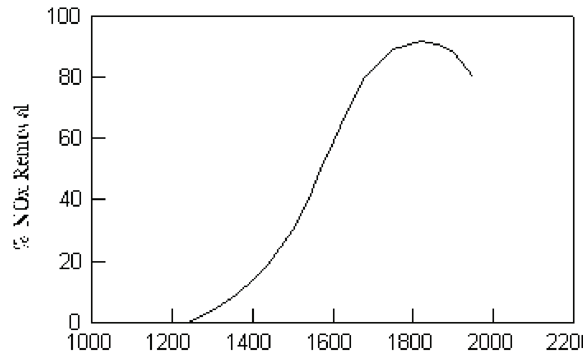

Figure 2. Typical SNCR Temperature Ranges

A further increase in temperature beyond the plateau decreases NO_x reduction. On the right side of the curve, the oxidation of reagent becomes a significant path and competes with the NO_x reduction reactions for the reagent. Although the efficiency is less than the optimum, operation on the right side is practiced and recommended to minimize byproduct emissions. On the left side of the curve, there is also greater potential for ammonia slip for a given NO_x removal and residence time.

The effective temperature window becomes wider as the residence time increases, thus improving the removal efficiency characteristics of the process. Long residence times (>0.3 second) at optimum temperatures promote high NO_x reductions even with less than optimum mixing.

Normal stoichiometric ratio (NSR) is the term used to describe the N/NO molar ratio of the reagent injected to the uncontrolled NO_x concentrations. In general, one mole of ammonia species will react with one mole of NO in the reduction reaction. If one mole of anhydrous ammonia is injected for each mole of NO_x in the flue gas, the NSR is one, as one mole of ammonia will react with one mole of NO_x. If one mole of urea is injected into the flue gas for each mole of NO_x, the NSR is two. This is because one mole of urea contains two ammonia radicals and will react with two moles of NO_x.[3] For both reagents, the higher the NSR, the greater the NO_x reduction. Increasing NSR beyond a certain point, however, will have a diminishing effect on NO_x reduction with a resultant increase in ammonia slip and reagent cost.

Is SNCR a new technology?

No. Commercial installations using SNCR have been in existence for more than 30 years.

The first commercial application of SNCR was in Japan in 1974.[4] This installation used anhydrous ammonia. At about the same time, the anhydrous ammonia injection process was patented in the U.S. by Exxon Research and Engineering Co. This process is commonly known as the Thermal $DeNO_x$ process.

Fundamental thermodynamic and kinetic studies of the NO_x-urea reaction occurred during 1976-1981 under the direction of the Electric Power Research Institute (EPRI). Patents granted to EPRI for this process were licensed to Fuel Tech which, with its implementors and sub-licensees, has marketed the urea-based NOxOUT[R] process with improvements to the original patents.

Is SNCR commercially deployed?

SNCR systems are in commercial operation in the United States, as well as in Europe and Asia and is one of the key technologies used for compliance with the NO_x SIP Call program.

SNCR is a fully commercial NO_x reduction technology, with successful application of the urea- and ammonia-based processes at approximately 400 installations worldwide (see Appendix 1 and 2), covering a wide array of stationary combustion units firing an equally diverse types of fuels.

In the U.S., commercial installations or full-scale demonstrations include virtually every boiler configuration and fuel type, as well as other major NO_x emitting process units, such as cement kilns and incinerators. Urea-based SNCR has been applied commercially to sources ranging in size from a 60 MMBtu/hr (gross heat input) paper mill sludge incinerator to a 640 MWe pulverized coal-fueled, wall-fired electric utility boiler. The earliest commercial urea-based SNCR system in the U.S. was installed in early 1988 on a 614 MMBtu/hr CO boiler in a Southern California oil refinery. This SNCR system reduces NO_x emissions 65 % from a baseline of 90 ppm.

Industrial boilers, process units, municipal and hazardous waste combustors, and power boilers make up the largest share of commercial SNCR installations in the U.S. This distribution is determined more by NO_x control regulations than by SNCR process limitations. To illustrate the breadth of deployment of SNCR, the following examples of commercial installations include:

- Two 500 MWe cyclone-fired boilers at Ameren utilize a combination of SNCR with RRI®, which is an offshoot of SNCR technology under license with EPRI.
- Two 75 MWe pulverized coal tangentially fired power boilers in California equipped with low NO_x burners and overfire air required the installation of SNCR to meet a 165 ppm permit limit.[5]
- SNCR systems installed on the coal-burning, wall-fired Dominion Energy's Salem Harbor Station Units 1, 2 (84 MWe each) and 3 (156 MWe) in 1993, together with LNBs, can reduce NO_x emissions 50-75 % from a baseline of 0.85-1.12 lb/MMBtu.
- Commercial SNCR systems retrofit on 320 MWe wet-bottom, twin furnace boilers in New Jersey provide 30-35 % NO_x reductions.[6]
- Commercial SNCR systems retrofit on cyclone-fired boilers in New Jersey reduce NO_x emissions by 35-40 %.
- SNCR is achieving compliance with RACT limits at coal-fired boilers in Massachusetts[7] and Delaware.[8]
- A SNCR system installed on a 640MW supercritical boiler is achieving 25 % removal efficiency using only wall injectors. This option offers lower cost (about $6/KW including installation) than utilizing multi-nozzle lances.
- SNCR systems at Duke Energy's Marshall Station on 600 MWe boilers incrementally reduced NO_x by 25 % above the reductions being obtained with LNB.
- An SNCR system installed on a circulating fluidized bed boiler designed to produce 350,000 lb/hr of steam can reduce NO_x emissions from a baseline of 0.2-0.35 lb/MMBtu to below 0.15 lb/MMBtu over a load range of 40-100 %.[9]
- Among significant applications in the U.S.:
- A SNCR system on a 600 MW coal-fired boiler firing 3.5 % sulfur coal reduced NO_x by 30 % across the load range while maintainging ammonia slip near 5 ppm. The unit experienced very few operational difficulties.[10]
- SNCR, in conjunction with combustion tempering, is achieving NO_x reductions of nearly 60 % on a 244 MWe gas-fueld cyclone boiler.[11]
- SNCR, in conjunction with burner optimizations, reduced NO_x on coal over 70 % on coal fired boilers.[12]
- SNCR provided an 80+ % reduction from uncontrolled emissions of 3.5-6.0 lb NO_x per ton of clinker in a demonstration at a West Coast cement kiln.
- A SNCR system in combination with a modified reburn process is meeting 0.2 lb/MMBtu on a 600 MW boiler firing Powder River Basin coal.

SNCR also has been commercially installed and demonstrated in Asia. For example, an SNCR system installed on a 331 MMBtu/hr pulverized coal-fired industrial boiler in Kaohsuing, Taiwan, in 1992 reduced

NO_x emissions from this front-fired boiler from 300 to 120 ppm.

In addition, SNCR has been commercially installed throughout Europe. Installations include coal-fueled district heating plant boilers, electric utility boilers, municipal waste incinerators, and many package boilers.

In Germany, commercial SNCR systems installed on municipal waste incinerators in Hamm, Herten, and Frankfurt reduce NO_x emissions 40-75 % from baselines of 160-185 ppm. SNCR also has been installed on more than 20 heavy oil-fired Standardkessel package boilers.

In Sweden, a commercial SNCR system on a 275 MMBtu/hr coal-fueled, stoker-fired boiler at the Linkoping P1 district heating plant reduces NO_x emissions 65 % from a baseline of 300-350 ppm. At the Nykoping demonstration on a 135 MMBtu/hr coal-fueled circulating fluidized-bed boiler, SNCR achieves a 70 % NO_x reduction from a 120-130 ppm baseline. Demonstrations of SNCR, in addition to municipal waste incinerators and wood- and coal-fueled district heating plant boilers, included a pulp and paper mill kraft recovery boiler, where a 60 % reduction from uncontrolled emissions of 60 ppm was attained.[13]

To meet new environmental demands in Eastern Europe, SNCR systems were installed on five coal-fired industrial boilers in the Czech Republic since 1992.

Are there applications for which SNCR is particularly suited?

Yes. Some applications have combinations of temperature, residence time, unit geometry, and uncontrolled NO_x level, and operating modes which make them especially well-suited for cost-effective reduction of NO_x by SNCR.

Certain applications are technically well-suited for the use of SNCR. These include combustion sources with exit temperatures in the 1550-1950 ºF range and residence times of one second or more, examples of which are many municipal waste combustors, sludge incinerators, CO boilers, and circulating fluidized bed boilers. Furnaces or boilers with high NO_x levels or which are not suited to combustion controls, e.g., cyclone-type or other wet bottom boilers and stokers and grate-fired systems, also are good candidates for SNCR.

Other applications are well-suited to the use of SNCR for economic reasons. For these applications, controls with reduced capital cost, even at the expense of somewhat higher operating costs, may be the least expensive to operate. Applications meeting these criteria include units with lower capacity factors, such as peaking and cycling boilers, units requiring limited control, e.g., additional “trim” beyond combustion control or seasonal control.

How much does SNCR cost?

The capital cost of a selective non-catalytic reduction system is among the lowest of all NO_x reduction methods. Recent innovations in the control of reagent injection make SNCR operating costs amongst the lowest of all NO_x reduction methods.

SNCR is an operating expense-driven technology, so that the absolute cost of applying SNCR varies directly with the NO_x reduction requirements.

Typical SNCR capital costs for utility applications are $5-15/kW, vendor scope, which corresponds to a maximum of $20/kW if balance-of-plant capital requirements are included. For example, the total capital requirement for the commercial installation of SNCR at New England Electric’s Salem Harbor Station (three pulverized coal-fired boilers) was $15/kW.[14] Similarly, total capital requirements for Public Service Electric and Gas’ Mercer Station Unit 2 and B.L. England Station Unit 1 were $10.6/kW and $15/kW, respectively.[15] Southern California Edison reported an even lower capital requirement of $3/kW for installing “urea injection” on 20 units totaling 5600 MW[16].

On an updated turn-key basis, a typical SNCR would range from $1325-7000/MMBtu/hr depending on the process category. An example of a high cost application, might apply to an all-in cost for an extremely small rotary kiln. On the opposite end, the lower cost applications are typically large hazardous waste incinerators and large bubbling bed/fluidized bed boilers and large wood-fired stokers.

For similar type sources, the installed capital cost per unit of output (e.g., $/kWe) decreases as the source size increases, i.e., due to economy of scale, total capital outlay increases less than linearly with increasing boiler capacity.

Given such low capital requirements, most of the cost of using SNCR will be operating expense. A typical breakdown of annual costs for utilities will be 25 % for capital recovery and 75 % for operating expense. For industrial sources, annual costs will be 15-35 % for capital recovery and 65-85 % for operating expense. For an operating expense-driven technology, little cost will be incurred if the source is not operating, and cost effectiveness (the cost per ton of NO_x removed) will be relatively insensitive to capacity factor or duty cycle. This makes SNCR particularly attractive for seasonal control of NO_x emissions. (For capital-intensive technologies, cost effectiveness becomes worse with decreasing capacity factor.)

Demonstrated cost-effectiveness values for SNCR are low, ranging from $400 to $3,000 per ton of NO_x removed, depending upon site-specific factors. For example, the cost effectiveness of SNCR at Dominion Energy’s Salem Harbor Station unit 2 is $670/ton.[17] The wide range exists because of differing conditions found across different facilities, even with in the same industry. For utility boilers alone, cost effectiveness varies with factors such as uncontrolled NO_x level, required emission reduction, unit size, capacity factor (or duty cycle), heat rate (or thermal efficiency), degree of retrofit difficulty, and economic life of the unit.

Of primary interest to electric utilities is the cost of pollution controls per unit of electricity generated, expressed on a busbar basis (mills/kWh). For SNCR, the busbar cost varies directly with the amount of NO_x to be removed. Costs range from less than 1.0 mill/kWh for "trim reduction" on a coal-fired unit or RACT-level reduction on an oil-fired unit, to 3.5 mills/kWh for a 75 % reduction on a unit with uncontrolled emissions greater than 1 lb NO_x/MMBtu. A commercial installation of urea-based SNCR on a Dominion Energy's unit has a busbar cost of 2.7 mills/kWh, and a cost effectiveness of approximately $1,000/ton. (To convert the busbar costs of SNCR to a cost increment relative to fuel price, 0.5-3.5 mills/kWh is roughly equivalent to $0.05-$0.35/MMBtu.)

Innovations in SNCR control systems and continued system optimization during operation have reduced reagent usage at commercial installations, thus decreasing operating costs further. At one coal-fired utility boiler, a control upgrade, including continuous ammonia and temperature monitors, improved control hardware and software, and additional injector pressure controls, allow over a 50 % decrease in reagent use from baseline levels.[18] At a second coal- and oil-fired unit, system optimization after start-up has lowered reagent consumption 35 % below predicted levels.[19] Given that the reagent dominates SNCR operating cost, such large reductions in reagent use translate to significant reductions in operating cost.

What about ammonia slip?

Ammonia slip, or emissions of ammonia which result from incomplete reaction of the NO_x reducing reagent, typically can be limited to low levels.

Ammonia slip may result in one or more problems, including:

- Formation of ammonium bisulfate or other ammonium salts which can plug or corrode the air heater and other downstream components;
- Ammonia absorption on fly ash, which may make disposal or reuse of the ash difficult;
- Formation of a white ammonium chloride plume above the stack; and,
- Detection of an ammonia odor around the plant.

Ammonia slip is controlled by careful injection of reagent into regions of the furnace or other sources where proper conditions (temperature, residence time, and NO_x concentration) for the SNCR reaction exist. If the reagent reacts in a region where the temperature is too low for the NO_x-reducing reaction to occur in the available residence time, then some unreacted ammonia will be emitted. Further, if reagent is injected in such a way that some regions of the furnace are over treated, the excess reagent can lead to ammonia slip. Thus, it is critical that the SNCR injection system be designed to provide the appropriate reagent distribution.

The difficulty in controlling ammonia slip will vary from application to application. At many commercial installations, particularly in electric utilities, units have operated with ammonia slip levels of equial to or less than 5 ppm upstream of the air heater to meet the requirements of owners or permitting authorities. This is a far more stringent criterion than stack emissions. In any case, ammonia concentrations at ground level will be well below thresholds for both odor and toxicity.

Control system upgrades and process optimization after installation can lower slip below guaranteed levels. Thus, at a commercial SNCR system on a coal-fired boiler, improved controls have lowered ammonia slip from 10-15 ppm to below 5 ppm, and have reduced ammonia on the fly-ash by half.

Use of a down-sized SCR downstream of a SNCR also optimizes the integration to ammonia-sensitive units.

Does SNCR have other limitations?

As do all pollution control technologies, SNCR has limitations which must be understood in order to use it properly to optimize the control of NO_x emissions.

High temperature and critical NO_x concentration. As temperature increases, the "critical" or equilibrium NO_x concentration at a given oxygen concentration increases. At high enough temperatures, any reduction of NO_x to below the critical level by SNCR or other means will be counteracted by the rapid oxidation of nitrogen to re-form NO_x. For this reason, at sufficiently high temperatures and baseline NO_x levels below the critical concentration, injection of ammonia or urea into the flue gas will result in *increased* NO_x levels. If, however, the baseline NO_x concentration is above the critical level, NO_x reduction will result. For typical coal- and oil-fired steam boilers, critical NO_x levels are 70-90 ppm (ca. 0.1 lb/MMBtu) in the upper furnace.

High furnace carbon monoxide concentration. High CO concentrations can shift the temperature window of the SNCR process. When CO concentrations in the region of reagent injection are above 300 ppm, the critical NO_x level and SNCR reaction rate will increase above what they would have been had little CO been present, as if the temperature were slightly higher. Therefore, in some furnaces with high CO levels, it is preferable to inject reagent at lower temperatures to effect good NO_x control.

Carbon monoxide emissions. In a well-controlled urea-based SNCR system, the carbon contained in the urea is fully oxidized to carbon dioxide. Normally, steps taken to control ammonia slip impose sufficient restrictions on reaction temperature to prevent substantial emissions of CO.

What are common misconceptions regarding SNCR?

In earlier days, several common misconceptions initially slowed the acceptance of SNCR by utilities.

Misconception: As boiler size increases, SNCR efficiency decreases. As long as reagent can be distributed, there is no technical limitation to the size of boilers on which SNCR will be effective. This misconception arose in part from the earliest experiences at large utility boilers in California. These boilers were equipped with low NO_x combustion systems, had high furnace exit gas temperatures, and very rapid cooling of the gases in the boiler convective regions. Low baseline NO_x levels resulting from these natural gas-fired boilers and rapid cooling led to low NO_x control efficiencies and high ammonia slips using SNCR. Increased technical knowledge and experience have allowed better delineation of the limitations of the SNCR process, which since then has been used to achieve over 60 % NO_x reductions on some electric utility boilers.

The commercial development of retractable multi-nozzle lances as well as advances in feed-forward controls has extended the applicability of urea-based SNCR technology. These advances enable delivery of reagent across the boiler, as has been demonstrated both in the U.S. and abroad. Today, there are several facilities utilizing SNCR on units of greater than 600 MW capacity.

Misconception: SNCR cannot be used on boilers equipped with low NO_x combustion controls. SNCR has been installed commercially on boilers equipped with low NO_x burners, overfire air, and flue gas recirculation, and has been shown to operate effectively with all of these technologies.[20] Typically, SNCR reduces NO_x an additional 20-30 % above LNB/combustion modifications.

Misconception: Use of SNCR on coal-fired plants results in fly ash which cannot be sold and the disposal of which is expensive. The tendency of fly ash to absorb ammonia is a function of many factors in addition to the amount of ammonia slip. Ash characteristics such as pH, alkali mineral content, and volatile sulfur and chlorine content help to determine whether or not ammonia will be absorbed readily by the fly ash. In most applications, properly designed SNCR systems will keep the ammonia slip levels low enough so that the salability of the ash should be unaffected.

Can SNCR be used in combination with selective catalytic reduction (SCR)?

Hybrid SNCR-SCR systems have been demonstrated at a number of utility plants, and are being commercially installed to meet post-RACT NO_x limits.

SNCR may be combined with selective catalytic reduction (SCR) using a number of different techniques. NO_x control with an SNCR system alone is often limited by ammonia slip requirements. One commercially available hybrid SNCR-SCR system design generates ammonia slip intentionally as the reagent feed to the SCR catalyst, which provides additional NO_x removal. The quantity of catalyst required in a hybrid system can be reduced from that of an SCR-only application, so that the hybrid system could have lower capital requirements.

At two gas-fired utility boilers in Southern California, hybrid systems gave emissions reductions of 72-91 percent.[21] At a wet bottom coal-fired boiler in New Jersey, a hybrid system reduced NO_x emissions by up to 98 percent. In a DOE Clean Coal Technology installation, the combination of SNCR with smaller SCR will reduce NO_x below 0.15 lb/mmBtu at less than two-thirds the cost of full SCR.[22] This hybrid approach has been demonstrated in several full-scale utility applications and as a result of the installation at AES Greenidge has been commercially applied. SNCR can also be applied to units with a conventional SCR system with a standard ammonia injection grid.

How can SNCR be used to best advantage?

The features of being a low hazard, low capital cost, expense-driven technology that requires little space and little unit down-time to implement suggests various appropriate uses to comply with U.S. clean air regulations.

Beyond-RACT Controls for Ozone Attainment. States not meeting the ozone National Ambient Air Quality Standard after application of RACT controls will require greater NO_x reductions from sources within their borders. Many states presume that these reductions will be based on the addition of post-combustion controls, including SNCR. In some cases, SNCR could be retrofit to units that already have implemented combustion modifications. Where SNCR has been used to meet RACT limits, the reagent use rate could be increased to meet new, lower limits.

Seasonal Controls for Ozone Attainment. In a seasonal approach, NO_x reductions beyond RACT would be required only during the “ozone season” (May through September) when exceedances normally occur. For example, the states of the northeast Ozone Transport Region have committed to a plan calling for control of ozone precursors only during the May-September ozone season to help meet regional ozone attainment goals. SNCR is particularly well-suited for seasonal control in that it may provide deep reductions in NO_x emissions, but incurs little cost when the system is not in use. For urea-based SNCR, the incremental cost of control during the ozone season would be on the order of $0.30/MMBtu on a unit without low-NO_x burners, expressed as a fuel cost adder relative to the “off” season.

Acid Rain Control. Under the acid rain provisions (Title IV) of the Clean Air Act Amendments, NO_x limits for Group 2 coal-fired utility boilers, which include cyclones, wet-bottom wall-fired boilers, cell-burner-fired boilers, stoker-fired units, and roof-fired boilers were promulgated in 1996 based upon the capabilities and costs of available control technologies.

SNCR technology has been successfully installed on cell-, pulverized-coal wet bottom-, cyclone-, and stoker-fired units as well as on circulating fluidized bed boilers.

Overcontrol. The low capital cost and ease of retrofit of SNCR suggest its use as an add-on to other NO_x control technologies to provide overcontrol, or control to below permit limits. Overcontrol can be useful where the marginal cost of control on one unit is lower than on other units, and where averaging or trading emissions or emissions reductions is permitted. Trading provisions of the proposed NO_x SIP Call regulation, the Regional Clean Air Incentives Market (RECLAIM) instituted by the California South Coast Air Quality Management District, the acid rain NO_x rule, and proposed rules for generation of emissions reduction credits all authorize strategies based on overcontrol.

In an overcontrol strategy, a second SNCR system may be used to provide insurance: If the overcontrolled unit in the averaged group is forced out of service, the insurance system is available to provide the requisite emissions reductions on a second unit. When the overcontrolled unit is in service, the cost of the insurance SNCR system is limited to a relatively low capital charge.

BACT/New Source Controls. SNCR has been utilized to fulfill best achievable control technology (BACT) requirements for new stoker units in Maine, Vermont, Massachusetts, Connecticut, and Virginia, among other states. In North Carolina, a new pulverized coal-fired unit was permitted recently with SNCR to meet a 0.17 lb/MMBtu NO_x emission limit.

What are the water quality considerations where urea or aqueous ammonia is utilized for SNCR?

Water quality and product handling are important components of the overall successful operation of the emissions control system when urea or aqueous ammonia reagents are used in post-combustion applications. Water quality is important in order to minimize system fouling and corrosion that can result in reduced SNCR system on-line time, higher maintenance costs, and the inability to meet emissions targets. Proper product handling and storage equipment is necessary in order to assure that the quality of the reagents have the optimum characteristics for industrial emissions control applications.

With urea-based SNCR systems, urea is generally shipped as a 50 percent solution but is also available and shipped from a range of concentrations from 32 percent to 70 percent solution. Depending on the urea manufacturer, the water used to ship urea may be demineralized for quality purposes. Prior to injection, urea solution is diluted in-line anywhere from 50 percent to 80 percent. Water quality for this dilution step is important to the success of the application because urea (as well as ammonia) is highly alkaline in water and will precipitate hardness and other minerals. Demineralized water will remove any potential suspended solids which may lead to plugging of injection lances and other components of the SNCR system. The dilution water for SNCR remains stable if: (1) urea is purchased from suppliers who supply "NO_x grade urea liquor" whereby stabilizers have been mixed into the solution, or (2) otherwise the dilution water should be of high quality which can be achieved through demineralization or reverse osmosis type processes in order to provide maximum insurance. Table 1 provides a range of physical properties for varying concentrations of urea liquor seen in typical SNCR applications.

Table 1. Range of Properties for SNCR Grade Urea Liquor from Demineralized Water

Characteristic	*Range*
Urea Concentration	32 to 70
Free Ammonia (at loading)	<0.2% to <0.5 %
Biuret (at loading)	<0.3 % to <0.7 %
Magnesium (Mg) ppm	<0.5 to <0.8
Calcium (Ca) ppm	<0.5 to <0.8
Phosphates as PO_4 ppm	<0.5 to <1.5
Iron (Fe) ppm	<0.5 to <0.8

Urea supply chain and storage is important in order to provide the quality assurance and quality control of the urea liquor used for SNCR systems. The vast majority of anhydrous ammonia and urea manufactured in North American is produced for agricultural purposes where water quality in the make-up/dilution water is less of an issue. For anhydrous ammonia and urea that is produced domestically, between 85-90 percent is used for fertilizer. Agricultural applications place a higher priority on the nitrogen value and certain physical characteristics of the urea to ensure that the fertilizer is evenly distributed when fertilizing fields. Urea and anhydrous ammonia that is produced for SNCR grade applications has a higher standard for the quality of the water used for the make-up/dilution processes. Although supply is available in most locations in North America, the actual distance between point of production and final use can add up to tens of thousands of miles of transport by road, rail, ship, and pipeline involving material handling at each step of the delivery process. Some manufacturers have dedicated supply and storage systems for SNCR grade urea and anhydrous ammonia in order to ensure that this is no contamination between agricultural and industrial grade products. Although not mandatory, minimizing the risk of contamination of the urea or anhydrous ammonia during the supply chain will ensure that the supply of reagent meets the tight quality control requirements demanded in the air emissions control systems.

APPENDIX 1: Selected Applications of Urea-Based SNCR, by Industry

COMPANY / LOCATION	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm)	REDUCTION %
Utility Boilers					
American Electric Power Cardinal Station Unit #1 Brilliant, OH	B & W Universal Press.	5347 (600 MW)	Coal	0.57 lb/MMBtu	30
AEP - Southwestern Electric Power Pirkey Station Unit 1 Hallsville, TX	B&W Opposed Wall Fired	6900 (710 MW)	Coal	0.19 lb/MMBtu	20
Dynegy Danskammer Unit 4	CE T-Fired	240 MW	Coal	0.25 lb/MMBtu	20
Reliant Energy Shawville Unit 2	B&W Wall Fired	133 MW	Coal	0.5 lb/MMBtu	25
Alabama Power Gaston Station Unit 3 Wilsonville, AL	B&W Opposed Wall Fired	2474 (250 MW)	Coal	0.44 lb/MMBtu	25
Ameren Sioux Station Unit 1	Cyclone	510 MW	PRB Coal	0.25 lb/MMBtu	50
AES/Indianapolis Power and Light Harding Street Station Units 5 and 6	C.E. T-Fired	110 MWg each	Coal	0.36 lb/MMBtu	30-40
Alabama Power Barry Units 1-4 Bucks, AL	T-Fired T-Fired Twin Furnace T-Fired	153 MW 153 MW 272 MW 400 MW	Coal Coal Coal Coal	0.49 lb/MMBtu 0.46 lb/MMBtu 0.40 lb/MMBtu 0.29 lb/MMBtu	27.5 27.5 25 25
Atlantic Electric B.L. England Station (3 units) Mays Landing, NJ	Cyclone Cyclone T-Fired	138 MW 160 MW 160 MW	Coal Coal #6 Oil	1.31 lb/MMBtu 1.40 lb/MMBtu 0.31 lb/MMBtu	31.3 36 35
Austrian Energy Vojany Power Station Slovak Republic	Utility	1146	Pulverized Coal	789 mg/Nm3 @ 11% O2 1.58 *	32
Cinergy Miami Fort Unit #6 Northbend, OH	Tangential Fired C.E.	1490	Coal	0.55 lb/MMBtu	35
Delmarva Power Wilmington, DE	T-fired	84 MWe	Coal	0.54 lb/MMBtu	30
Dominion Generation Clover Station, Units 1 & 2 Clover, VA	CE T-Fired	465 MW each	Coal	0.32 MMBtu	25
Dominion/NEPCO Unit 1 Salem Harbor, MA	Front-Fired	84 MW	Coal	1.00 ± 0.10 *	~ 66 **
Dominion/NEPCO Unit 2 Salem Harbor, MA	Front-Fired	84 MW	Coal	1.00 ± 0.10 *	~ 66 **
Dominion/NEPCO Unit 3 Salem Harbor, MA	Front-Fired	156 MW	Coal	1.00 ± 0.10 *	~ 66 **

COMPANY / LOCATION	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm)	REDUCTION %
Duke Energy Allen Station Unit 1 Belmont, NC	CE T-Fired	1751 (185 MW)	Coal	0.22 lb/MMBtu	25
Duke EnergyAllen Station Unit 2Belmont, NC	CE T-Fired	1751 (185 MW)	Coal	0.22 lb/MMBtu	TBD
Duke Energy Allen Station Unit 3 Belmont, NC	CE Twin Furnace	2546 (270 MW)	Coal	0.22 lb/MMBtu	23
Duke Energy Allen Units 4 & 5 Belmont, NC	CE Twin Furnace	2546 (270 MW)	Coal	0.22 lb/MMBtu	23
Duke Energy Buck Station Units 5 & 6 Salisbury, NC	CE T-Fired	1230 (142 MW)	Coal	0.20 lb/MMBtu	20
Duke Energy Marshall Station Unit 3 Terrell, NC	CE 8-Corner	6130 (660 MW)	Coal	0.267 lb/MMBtu	20
Duke Energy Marshall Station Units 1 & 2 Terrell, NC	CE 8-Corner	3367 (350 MW)	Coal	0.245 lb/MMBtu	20
Duke Energy Riverbend Station Units 4 & 5 Salisbury, NC	CE T-Fired	937 (100 MW)	Coal	0.25 lb/MMBtu	TBD
Duke Energy Riverbend Station Units 6 & 7 Salisbury, NC	CE T-Fired	1318 (133 MW)	Coal	0.20 lb/MMBtu	TBD
Exelon Philadelphia Electric Co. Cromby Station, Unit 1 Phoenixville, PA	B&W Divided Furnace	1480	Coal	0.50 lb/MMBtu	25
Exelon Eddystone Station Units 1-2 Eddystone, PA	T-Fired Twin Furnace	318 MWg 333 MWg	Coal	0.26 lb/MMBtu	~ 30%
First Energy East Lake Unit 3 East Lake, OH	CE 8-Corner	1470 (120 MW)	Coal	0.34-0.40 lb/MMBtu	20 - 32.5
First Energy East Lake Unit 5 East Lake, OH	B & W Universal Press.	620 MWg	Coal	0.38 lb/MMBtu	25
First Energy Sammis Unit 1 Sammis, OH	FW Front Wall Fired	180 MW	Coal	0.38 lb/MMBtu	25
First Energy Sammis Unit 2 Sammis, OH	FW Front Wall Fired	180 MW	Coal	0.38 lb/MMBtu	25

COMPANY / LOCATION	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm)	REDUCTION %
First Energy Sammis Unit 3 Sammis, OH	FW Front Wall Fired	180 MW	Coal	0.38 lb/MMBtu	25
First Energy Sammis Unit 4 Sammis, OH	FW Front Wall Fired	180 MW	Coal	0.38 lb/MMBtu	25
First Energy Sammis Unit 5 Sammis, OH	B&W Wall Fired	300 MW	Coal	0.45 lb/MMBtu	25
First Energy Sammis Unit 6 Sammis, OH	B & W Universal Press.	620 MWg	Coal	0.38 lb/MMBtu	25
First Energy Sammis Unit 7 Sammis, OH	B & W Universal Press.	620 MWg	Coal	0.38 lb/MMBtu	25
Gulf Power Company Crist, Unit 6 Pensacola, FL	FWEC	320 MW	Coal	0.35 lb/MMBtu	~ 30
Korean Electric Power Co. Honam Station, Units 1 & 2 Korea	Front & Rear Wall-Fired	2474	Coal	0.654 lb/MMBtu	40
Northeast Utilities Schiller Station Units 4, 5 & 6 Portsmouth, NH	Foster Wheeler Front Fired	50 MW each	Coal	0.45 lb/MMBtu	50
NRG/Eastern Utilities Somerset, MA	Tilting T-Fired Boiler	410-1120	Coal, Oil	0.49 – 0.89 lb/MMBtu	28 – 60
NRG/Northeast Utilities Middletown Unit 3 Middletown, CT	Cyclone-Fired	2455 MMBtu/hr	Gas	0.34 lb/MMBtu	25
NRG/Northeast Utilities Norwalk Harbor Station, Units 1&2 S. Norwalk, CT	CE Twin T-Fired	172 MWg 182 MWg	Oil	< 0.40 *	< 0.25
Pennsylvania Electric Company Comby Station	B&W Divided Furnace	1480	Coal	0.5 lb/MMBtu	25
PSE&G Hudson Station, Unit #2 Jersey City, NJ	Foster Wheeler Opposed Wall	660 MWg	Coal Natural Gas	0.65 lb/MMBtu 0.35 lb/MMBtu	25 25
Reliant Energy/Penelec Seward Unit 15	CE-T-Fired	1457 MMBtu/hr	Coal	0.78 lb/MMBtu	35
Rochester Gas & Electric Russell Station, Units 1-4	CE T-Fired	265 MW Total	Coal	0.28 - 0.42 lb/MMBtu	15 – 27.5
Tennessee Valley Authority Johnsonville Unit 1 Waverly, TN	CE T-Fired	125 MW	Coal	0.44-0.46 lb/MMBtu	25

COMPANY / LOCATION	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm)	REDUCTION %
Tennessee Valley Authority Shawnee Unit 1 Paducah, KY	B&W Front Wall-Fired	145 MW	Coal	0.43 lb/MMBtu	25
Northern Indiana Public Service Schahfer Station #14	Cyclone-Fired	520 MW	Coal	SCR Reagent Requirement 1200 lb/hr	
Northern Indiana Public Service Bailly Station #8	Cyclone-Fired	360MW	Coal	SCR Reagent Requirement 1100 lb/hr	
Northern Indiana Public Service Michigan City Station #12 Michigan City, IN	Cyclone-Fired	520 MW	Coal	SCR Reagent Requirement 1200 lb/hr	
Reliant Energy/Penelec Seward Unit 15	Tangential Fired C.E.	1457	Coal	0.78 lb/MMBtu	55
Wisconsin Electric Power Co. Pleasant Prairie Unit #1 Kenosha, WI	Riley Turbo	6260 (620 MWg)	Coal	0.45 lb/MMBtu	56
PSE&G Mercer Station Unit 1 Furnace #11 & #12 Trenton, NJ	Front Wall-Fired Wet Bottom	320 MW Twin Furnace	Pulv. Coal	1.40 lb/MMBtu	60
PSE&G Mercer Station Unit 2 Furnace #21 & #22 Trenton, NJ	Front Wall-Fired Wet Bottom	320 MW Twin Furnace	Pulv. Coal	1.40 lb/MMBtu	60
PSE&G Hudson Station, Unit #2 Jersey City, NJ	Foster Wheeler Opposed Wall	660 MWg	Coal Natural Gas	0.65 lb/MMBtu 0.35 lb/MMBtu	40 40
Progress Energy Carolinas Asheville Unit 1 Skyland, NC	Riley Front Wall-Fired	2173 (200 MW)	Coal	0.58 lb/MMBtu	50
Wisconsin Electric Power Co. Pleasant Prairie Unit #1 Kenosha, WI	Riley Turbo	6260 (620 MWg)	Coal	0.45 lb/MMBtu	20
Industrial/Steel Industry					
China Steel Units 7 & 8 Taiwan - Republic of China	C.E. VU 40	156.8	Coal	0.568 lb/MMBtu	42.9
China Steel Unit 6 , Taiwan	CE T-Fired w/CCOFA	535	Coal	410 mg/Nm3 @ 11% O2	43
Demag Italimpianti S.p.A. Trieste, Italy	Steel plant	6200		1200 mg/Nm3 @ 11% O2	70
MHIA National Steel Portage, IN	Direct Fired Furnace	47.9	Natural Gas	0.30 lb/MMBtu	85
Nucor Steel, Hugor, S.C.	Preheat/ Radiant	50.8 20	Natural Gas	0.44 lb/MMBtu 0.31 lb/MMBtu	82 89
NKK Steel Engineering National Steel CGL #1 Portage, IN	Radiant Tube Annealing Furnace	117	Natural Gas	0.26 lb/MMBtu	90

COMPANY / LOCATION	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm)	REDUCTION %
NKK Steel Engineering National Steel Ecorse, MI	Cont. Galv. Line	117	Natural Gas	0.34 lb/MMBtu	90
Nucor Steel, Crawfordsville, IN	Reheat/ Radiant	58.8 14.3	Natural Gas	0.227 lb/MMBtu 0.581 lb/MMBtu	76
Nucor Steel, Hickman, AR	Preheat/ Radiant	46.7 14.6	Natural Gas	0.32 lb/MMBtu 0.46 lb/MMBtu	76 79
Protec/US Steel, CGL #1 Leipsic, OH	Radiant Tube Annealing Furnace	99	Natural Gas	0.589 lb/MMBtu	90
Protec/US Steel, CGL #2 Leipsic, OH	Radiant Tube Furnace	76.8	Natural Gas	0.253 lb/MMBtu	90
Selas/BHP Rancho Cucamonga, CA	Cont. Galv. Line	29	Natural Gas	105	65
WAPC Iron Dynamics Butler, IN	Rotary Hearth	435	Natural Gas	0.374 lb/MMBtu	30
Refinery Process Units and Industrial Boilers					
Corn Products North Carolina	Gasifier	262	Wood	163	20
UNOCAL Los Angeles, CA	Calciner HRSG		Petroleum Coke	45	53
UNOCAL Los Angeles, CA	CO Boiler	400	Refined Gas	140	68
ARCO CQC Kiln Los Angeles, CA	Calciner HRSG	651	Petroleum Coke	86	30
BP Toledo, OH	CO Boiler	518	Refinery Gas	95	22-35
MAPCO Petroleum Memphis, TN	Bottom-Fired Process Htr	177	Refinery Gas, Natural Gas	75	60
MAPCO Petroleum Memphis, TN	Bottom-Fired Process Htr.	50	Refinery Gas, Natural Gas	65	50 - 75
Mobil Oil Paulsboro, NJ	GT - HRSG	630	Refinery Gas	75	50
Mobil Oil Torrance, CA	CO Boiler	614	Refinery Gas	90	65
Mobil Oil/Macchi Yanbu, Saudi Arabia	Package Boiler	(3) 265	Vacuum Tower Bottoms Propane	0.40 lb/MMBtu	25
Pennzoil Shreveport, LA	CO Boiler/ Thermal Oxidizer		CO, Refinery Gas		
Pennzoil Shreveport, LA	CO Boiler/ Thermal Oxidizer	243	Natural Gas & Regen. Gas	0.27 lb/MMBtu	74

COMPANY / LOCATION	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm)	REDUCTION %
Powerine Santa Fe Springs, CA	CO Boiler	31 - 62	Refinery Fuel Gas	105	60
Powerine Santa Fe Springs, CA	Package Boiler	31 - 62	Refinery Fuel Gas	105	40
Shell Oil Martinez, CA	CO Boiler	(3) 222	Refinery Gas	230	65
Total Petroleum Alma, MI	CO Boiler	197	CO, Refinery Gas	1.20 lb/MMBtu	67
Pulp & Paper Industry					
Babcock and Wilcox Bowater, Calhoun, TN	BFB	821	Wood/Sludge	0.35 lb/MMBtu	62
Boise Cascade Intl. Falls, MN	Hydrograte Stoker	395	Bark, Gas	0.14-0.19 lb/MMBtu	25 - 35
C.C.T. Verzuolo, Italy	Paper Sludge	28.8 t/h		400 mg/Nm3 @ 11% O2	50
Energy Products of Idaho Italy	BFB	70.2	Paper/Landfill Sludge	0.587 lb/MMBtu	60.5
Garden State Paper, Unit #3 Garfield, NJ	Front-Fired Ind. Boiler	110	Fiber Waste	0.30 lb/MMBtu	50
Garden State Paper, Unit #4 Garfield, NJ	Front-Fired Ind. Boiler	172	Fiber Waste	0.20 lb/MMBtu	30
Jefferson Smurfit Jacksonville, FL	CE Grate-Fired	540	Coal, Bark, Oil	0.55-0.70 lb/MMBtu	20 - 35
Minergy Fox Valley Aggregate Plant Neenah, WI	B & W Cyclone	350	Paper Sludge/ Natural Gas	0.80 lb/MMBtu	62
P. H. Glatfelter Neenah, WI	Sludge Combustor	60	Paper Sludge	570	50
Potlatch Bemidji, MN	Wellons 4-Cell Burner	232	Wood Waste	0.30 lb/MMBtu	50
S. D. Warren Skowhegan, ME	CE Grate-Fired	900	Oil, Bark, Biomass	0.30 lb/MMBtu	46
Sodra Skogsagarna Sweden	Recovery Boiler	900	Black Liquor	60 mg/Nm3 @ 3% O2	60
Westvaco Phase I (Lukemill) #24 Luke, MD	B & W Cyclone	550	Coal	1.15 lb/MMBtu	50
Process Units					
Alcan Berea, KY (2 units)	Decoater/ Afterburner	30,000 lbs of aluminum cans/hr	Gas	90 - 130	50 - 80 +
Allis Minerals Oak Creek, WI	Rotary Kiln Incinerator	60	Paper Sludge	0.48 lb/MMBtu	57
Dow Chemical Midland, MI	Rotary Kiln w/Afterburner	145	Haz Waste	720 - 740	40 - 55

COMPANY / LOCATION	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm)	REDUCTION %
Eli Lilly Lafayette, IN	Haz Waste Incinerator	59	Haz Waste	290	70
Shinkong Synthetic Fiber Taiwan	Engine Generator	5.7 MW each	#6 Fuel Oil	1520 ppm @ 13% 02	85
Rollins Environmental Deer Park, TX	Haz Waste Incinerator	185	Chlorinated Chemical Waste, Soil	60 - 250	35 - 50
Univar/Chambers Medical Waste Incinerator Chambers County, TX (2 units)	Simonds Incinerator	221	Medical and Municipal	0.48 lb/MMBtu	67.8
Municipal Waste Combustors					
Ambiente Porto Marghera #1 Italy	Incinerator	109 t/h	Process Gas	204 mg/Nm3 @11% O2 0.28 *	60
Ambiente S.p.A. Scarlino, Italy	Incinerator	3 - 7 t/h		500 mg/Nm3 @ 11% O2	60
Bakelite Meiderich Germany (2 combustors)	Package Boiler	23870 Nm3/h		650	54
C.C.T. Faenza Italy	Confidential	Confidential	Confidential	Confidential	Confidential
CNIM Confidential England	Grate-Fired	28 t/h		400	55
Defisa Maresme Spain	Grate-Fired	10		500	60
Hamon Environmental Creteil, France	Rotary Kiln	32000 Nm3/h		140	50
HRCI Italy	Grate-Fired	10500 Nm3/h		370	46
K.N.T. Wismar, Germany	Grate-Fired	61000 Nm3/h		400	50
Maguin La Reunion, France	Rotary Kiln	8200 Nm3/h		300	33
Pfeiderer Gutersloh, Germany	Grate & Nozzle-Fired	93000 Nm3/h		600	66
Protecma Trieste Unit 3 Italy	Grate-Fired	43000 Nm3/h		400	50
SIVOM Metz, France	Incinerator	2 - 8 t/h		350 mg/Nm3 @ 11% O2	45
SMITOM Vaux le Pénil, France	Incinerator	2 - 8 t/h		350 mg/Nm3 @ 11% O2	45

COMPANY / LOCATION	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm)	REDUCTION %
Sirtec Nigi spA Le Havre, France	Waste Incinerator SCR	63,571 Nm3/h		350 mg/Nm3 @ 11% O2	82
Sirtec Nigi spA Nimes, France	Waste Incinerator SCR	77,000 Nm3/h		400 mg/Nm3 @ 11% O2	87
Bewag Germany	Tower	150 MW	Heavy Oil	200-225 mg/Nm3 @ 11% O2	60 - 70
Bremen, Germany	Grate Fired	15 t/h		350 mg/Nm3 @ 11% O2	45
City of Berlin Berlin, Germany	Moving Grate		MSW	160	69
City of Berlin Berlin, Germany	Zurn Stoker	167	MSW	275	75
RWE Germany	T-Fired	150 MW	Brown Coal	200-250 mg/Nm3 @ 11% O2	50
Sydkraft Sweden	PC Front-Fired	500	Coal	650 mg/Nm3 @ 11% O2	80
Yukong Ulsan, Korea	Package Boiler	34 TPH	#6 Oil	260-330 mg/Nm3 @ 11% O2	16 - 47
Emmenspitz Zuchwil, Switzerland	Detroit Stoker	137.5	MSW	110	60
Emmenspitz Zuchwil, Switzerland	Moving Grate Incinerator	121	MSW	200	68
Tekniskaverken Garstad, Sweden	Moving Grate		MSW		
Hallstehammer Sweden					
Wheelabrator West Millbury, MA (2 combustors)	Incinerator	351 / 750 TPD	MSW	300	32
AGEA MSW Ferrara, Italy	Incinerator	1 - 5 t/h		400 mg/Nm3 @ 11% O2	50
Alstom Power Daneco Pisa, Italy	Incinerator	2 - 8 t/h		400 mg/Nm3 @ 11% O2	50
Ambiente S.p.A. Porto Marghera, Italy	Incinerator	2 - 7 t/h		450 mg/Nm3 @ 11% O2	60
Ambiente S.p.A. Ravenna, Italy	Incinerator	1 - 12² t/h		500 mg/Nm3 @ 11% O2	60
American Ref-Fuel (CP) Hempstead Long Island, NY (3 combustors)	Deutshe Babcock Grate-Fired	320	MSW 768 T/D	0.44 lb/MMBtu	25

COMPANY / LOCATION	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm)	REDUCTION %
American Ref-Fuel Niagara Falls, NY (2 combustors)	Riley Grate	(2) 414	RDF, MSW	300	50
Ansaldo Arrezo Italy	Incinerator	51 t/h	MSW	460 mg/Nm3 @11% O2 227 *	56
Aster, R.S.U. Cremona 2° linea, Italy	Incinerator	1 - 8 t/h		400 mg/Nm3 @ 11% O2	50
Baltimore/Resco/WAPC Baltimore, MD	Burning Grate Stoker Fired	325	MSW	0.50 lb/MMBtu	30
Bremen, Germany (3 combustors)	Grate Fired	15 t/h		350 mg/Nm3 @ 11% O2	35
Bremen, Germany	Grate Fired	20 t/h		350 mg/Nm3 @ 11% O2	35
C.C.T. Airasca, Italy	Biomass	40000		400 mg/Nm3 @ 11% O2	60
C.C.T. Massafra, Italy	Biomass	95000		558 mg/Nm3 @ 11% O2	71
C.C.T. Termoli, Italy	Biomass	40000		400 mg/Nm3 @ 11% O2	60
CAECEM Fort France, Martinique	Incinerator	2 - 7		400 mg/Nm3 @ 11% O2	50
CNIM Spain	Grate Fired	30 t/h		400 mg/Nm3 @ 11% O2	50
Compagnia Energetica Bellunese Castellavazzo, Italy		8 t/h		800 mg/Nm3 @ 11% O2	50
Connecticut Resource Recovery Authority - Unit 13 Hartford, CT	CE VU 40	325	RDF, Coal	0.33-0.52 lb/MMBtu	35 - 40
Covanta Energy Babylon MSW NY (2 combustors)	Zurn Grate-Fired	142	MSW	320	53 - 66
CRRA - Units 11 & 12 Hartford, CT (2 combustors)	C.E. VU 40	326	RDF	0.52 lb/MMBtu	40
Cyclerval UK Grimsby, England	Incinerator	1 - 7 t/h	MSW	300 mg/Nm3 @ 11% O2	40
DB Riley, Central Wayne Dearborn, MI (3 combustors)	Municipal Waste Combustor	115 138	MSW	0.47 lb/MMBtu 0.48 lb/MMBtu	50
De Canderas Cremona, Italy	Municipal Waste Combustor		MSW/RDF	250 @ 11% O2	60
Deza Vitkovice Czech Republic	Wall Fired Boiler	362	Oil/Mazut	700 mg/Nm3 @ 11% O2	36
Dong Bu Ansan Proj (2 combustors) Korea	Steinmuller Incinerator Grate-Fired	281	MSW	200	75

COMPANY / LOCATION	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm)	REDUCTION %
Dong Bu Kwang Myong, Korea (2 combustors)	Municipal Waste Combustor	150 TPD	MSW	0.59	65
Ecoespanso S.Croce sull'Arno, Italy	Incinerator	52000 Nm3/hr		350 mg/Nm3 @ 11% O2	45
Falls Township Falls Township, PA	B&W Stoker	(2) 325	MSW	330 Max 285 Typ	50% Max 40% Typ
Fort Lewis Fort Lewis, WA	Municipal Waste Combustor	60 tons/day	MSW	230 @ 7% O2	65
Frankfurt Germany (4 combustors)	Moving Grate	660	MSW	170mg/Nm3 @ 11% O2	70
G.E.A (P) Pisa, Italy	Incinerator	1 - 7,5 t/h		350 mg/Nm3 @ 11% O2	43
Haindl Schwedt Germany	Fluidized Bed Incinerator	150	Pulp & Paper Waste	400-600 mg/Nm3 @ 11% O2	50 - 66
Hamm Germany (3 combustors)	Moving Grate	528	MSW	170mg/Nm3 @ 11% O2	41
Hamon Research Cottrell Italia Filago, Italy	Incinerator	93000		400 mg/Nm3 @ 11% O2	55
Hamon Research Cottrell Italia Lagny, Italy	Incinerator	8.80 t/h		450 mg/Nm3 @ 11% O2	55
Herten Germany (2 combustors)	Moving Grate	242	MSW	185mg/Nm3 @ 11% O2	60
Hornitex Germany	Incinerator	125	Wood	750 mg/Nm3 370	43
Keelung Taiwan (2 combustors)	Steinmuller	142	MSW	240 mg/Nm3 @ 10% O2	56
Kwang Myung Seoul, Korea (2 combustors)	Steinmuller MWC	58	MSW	200	65
Lerwick Shetland Islands, UK	Incinerator	1 - 4 t/h	MSW	350 mg/Nm3 @ 11% O2	45
LIPOR II Porto, Portugal	Incinerator	2 - 24,6 t/h		450 mg/Nm3 @ 11% O2	56
Meuselwitz Germany	Incinerator	45.2	Sludge	450 mg/Nm3 222	56
Montenay Resource Recovery Facility Montgomery, PA	Steinmuller MWC	(2) 260		0.385 lb/MMBtu	50
Montenay, Units 1-4 Dade County, Miami, FL	Zurn	302 / 623 TPD	RDF	170 - 250	14946
New Hanover County Wrightsville Beach, NC	Volund MWC	108	MSW	300	60
Nuova Romano Bolzicco S.p.A. Manzano, Italy	Biomass	35000		400 mg/Nm3 @ 11% O2	50

COMPANY / LOCATION	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm)	REDUCTION %
Pinellas County/WAPC Tampa, FL (3 combustors)	Municipal Waste Combustor	420	MSW	0.576 lb/MMBtu	33
Pisa Demonstration Italy	Incinerator	64.9 t/h	MSW	350 mg/Nm3 @11% O2 0.45 *	43
Pyong Chun Pyung Chon City, Korea	Municipal Waste Combustor	220 (200 TPD)	MSW	0.53 lb/MMBtu	65
R.S.U. Arrezzo Arezzo, Italy	Incinerator	1 - 6,5 t/h		460 mg/Nm3 @ 11% O2	57
R.S.U. Cremona Cremona, Italy	Incinerator	1- 8 t/h		500 mg/Nm3 @ 11% O2	60
Ravenna Italy	Municipal Waste Combustor	45,000 Nm3/hr	MSW	400	62.5
Regional Waste Systems ME, Units 1 & 2	Steinmuller	120	MSW	0.40 lb/MMBtu	33% 43% Design
Robbins Resource Recovery Facility Robbins, IL	FW CFB	(2) 309		0.39 lb/MMBtu	48.72
RWE - C2 Germany	T-Fired	75 MW	Brown Coal	150-175 mg/Nm3 @ 11% O2	40
Savannah Energy Systems Savannah, GA	Municipal Waste Combustor	115	MSW	0.71 lb/MMBtu	50
SEMASS Rochester, MA	Riley Stoker	375	MSW	220	50
Seoul Metro Gov't Mok-Dong - Seoul, Korea	MWC	62 150 TPD	MSW	100-150mg/Nm3 @ 11% O2	50-67
SETRAD La Rochelle, France	Incinerator	2 - 4 t/h		300 mg/Nm3 @ 11% O2	35
SILA Annecy, France	Incinerator	1 - 4 &2 - 6 t/h		350 mg/Nm3 @ 11% O2	50
Termomeccanica Ecologia Cagliari, Italy	Incinerator	1 - 8.75 t/h		450 mg/Nm3 @ 11% O2	60
Termomeccanica Ecologia Taranto, Italy	Incinerator	16 t/h		400 mg/Nm3 @ 11% O2	60
Termomeccanica S.p.A. Brindisi, Italy	Incinerator	1 - 8 t/h		450 mg/Nm3 @ 11% O2	66
Trmice Czech Republic (2 combustors)	Wall-Fired	490	Lignite	341 ppvd	57
TTR s.r.l. Busto Arsizio, Italy	Incinerator	2 - 5 t/h		400 mg/Nm3 @ 11% O2	50

COMPANY / LOCATION	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm)	REDUCTION %
TTR s.r.l. Trieste, Italy	Incinerator	2 - 5 t/h		400 mg/Nm3 @ 11% O2	50
Tuntex Kaohsiung MSW Taiwan (3 combustors)	Deutsche Babcock Incinerator	120 each	MSW	183 mg/Nm3 @ 10% O2	42
Ulm Germany	Bubbling Bed Sludge Incinerator		Sludge		
Vitkovice Czech Republic	Front Wall-Fired	250	Hard Coal	600 mg/Nm3 @ 11% O2	50
Westchester County/WAPC New York, NY (3 combustors)	Municipal Waste Combustor	325	MSW	0.50 lb/MMBtu	30
Wheelabrator North Broward, FL (3 combustors)	Incinerator	351 / 750 TPD	MSW	300	32
Wheelabrator South Broward, FL (3 combustors)	Incinerator	351 / 750 TPD	MSW	300	32
Wheelabrator RESCO Bridgeport, CT (3 combustors)	Grate-Fired	281	MSW	300	50
Wheelabrator RESCO Saugus, MA (2 combustors)	Incinerator	351 / 750 TPD	MSW	300	32
Wheelabrator Concord, NH (2 combustors)	Incinerator	110 / 250 TPD	MSW	300	32
Wheelabrator Gloucester, NJ (2 combustors)	Incinerator	109 / 250 TPD	MSW	300	32
Wheelabrator McKay Bay, FL (4 combustors)	Incinerator	108 / 250 TPD	MSW	306	51
Wheelabrator North Andover, MA (2 combustors)	Incinerator	351 / 750 TPD	MSW	300	32
Wilrijk. Germany	Grate Fired	9.6 t/h		350 mg/Nm3 @ 11% O2	50
Winterthur (1) Switzerland	Sludge Incinerator	8.34	Sludge	200-300 mg/ Nm3	60 - 73
Yilan Taiwan (2 combustors)	Steinmuller	142	MSW	240 mg/Nm3 @ 10%	56
Coal-, Wood-, Tire-Fired Industrial and IPP/Co-Generation Boilers					
Hamon Research Cottrell Italia Turkey (7 units)	Diesel SCR				
General Electric Lynn, MA	B&W "D" Type Pkg. Boiler	236	#6 Oil, Gas	0.28-0.31 lb/MMBtu	40 - 60
Honey Lake Power Susanville, CA	Stoker-Fired	480	Wood	0.21 lb/MMBtu	52
Oxford Energy Modesto #2, Wesley, CA	Moving Grate Incinerator	90	Tires	0.13 lb/MMBtu	40

COMPANY / LOCATION	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm)	REDUCTION %
Ultrasystems Fresno, CA	CFB	280	Wood	150	70
Yankee Energy Dinuba, CA	CFB	190	Wood Waste	0.10-0.18 lb/MMBtu	40 - 75
Tekniskaverken Linkoping P3 Sweden	Stoker		Wood	800mg/Nm3 @ 11% O2	50
ABB Okeelanta Okeelanta, FL	Grate-Fired Stoker	660	Bagasse Wood, Coal	0.40-0.20 lb/MMBtu	40 - 60
ABB Osceola Osceola, FL	Grate-Fired Stoker	660	Bagasse Wood, Coal	0.40-0.20 lb/MMBtu	40 - 60
AES Guyama, Puerto Rico (2 units)	CFB	250 MW	Coal	0.13 lb/MMBtu	23
Alternative Energy, Inc. Ashland, ME	Zurn Stoker	500	Wood	0.30 lb/MMBtu	50
Alternative Energy, Inc. Cadillac, MI	Zurn Stoker	500	Wood	0.30 lb/MMBtu	50
Alternative Energy, Inc. Northeast Empire Livermore Falls, ME	Zurn Stoker	500	Wood	0.30 lb/MMBtu	50
Black & Veatch Genessee, MI	ABB CE Stoker	473	Wood	0.47 lb/MMBtu	60
Black & Veatch Grayling, MI	Zurn Stoker	440	Biomass	0.26 lb/MMBtu	60
Celanese Narrows, VA	Front Wall-Fired	315	Coal	.360 lb/MMBtu	35 - 40
Chewton Glen Energy Ford Heights, IL	Grate-Fired	240	Shredded Tires	0.195 lb/MMBtu	60
Cogentrix Richmond, VA (8 units)	CE Stoker	(8) 28 MW	Coal	350	40
Far East Textiles Hsihpu, Taiwan	Stoker Boiler	190	Coal	550 @ 6% O2	50
FT GmbH Germany (5 units)	Fire Tube Pkg. Boilers	10 - 20 MW	Heavy Oil	700-800mg/ Nm3	40 - 50
Georgia Pacific Brookneal, VA	Wellons 4-Cell	236	Mixed Wood	0.33 lb/MMBtu	38
Georgia Pacific Mt. Hope, WV	Cell-fired	240	Bark/Dust	0.25 lb/MMBtu	20
Hyundai Korea Kumho Petrochemical	CFB	926	Pulv. Coal	275	56
I.P. Masonite Towanda, PA	B & W	250	Sludge/Wood Waste, Coal	0.4 lb/MMBtu	50

COMPANY / LOCATION	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm)	REDUCTION %
Kenetech Energy Fitchburg, MA	Riley Stoker	225	Wood	0.26 lb/MMBtu	47
Korea ICC Units 1 - 3 Kumi Heat & Power Station Korea	Front Wall-Fired	530 530 530	Pulv. Coal Pulv. Coal Pulv. Coal	710 700 710	53 53 40
LFC Hillman, MI	Grate-Fired	190	Wood	0.22 lb/MMBtu	30
McMillan Bloedel Clarion, PA	EPI Fluid Bed Combustor	500	Wood Waste/ Hog Fuel	100	42
Michigan State Univ., Unit #4 East Lansing, MI	CFB	460	Coal	247	57
Michigan State Univ., Units #1-3 East Lansing, MI	Wall Fired Boiler	320 320 420	Coal	0.38-0.40 lb/MMBtu	34-38
Nykoping, Units 1-3 Gotaverken Energy Sweden	CFB	135	Coal	120-130mg/Nm3 @ 1% O2	70
Oxford Energy Sterling, CT	Grate-Fired	(2) 170	Tires	0.15 lb/MMBtu	50
Ridge Generating Polk County, FL	Zurn Stoker	550	Wood	0.35 lb/MMBtu	57
Riley Ultrasystems II Weldon, NC	Riley Front-Fired Boiler	505	Pulv. Coal	0.33 lb/MMBtu	50
Ryegate Power Station Ryegate, VT	Riley Stoker	300	Wood	0.20 lb/MMBtu	30
Sierra Pacific Bohemia Plant Lincoln, CA	Cell-Fired	(2) 130	Biomass	0.42 lb/MMBtu	50
Sonoco Huntsville, SC	FW/ Pyropower CFB	145	Coal	195	67
Standardkessel Germany (31 units)	Fire Tube Pkg. Boilers	10 - 20 MW	Heavy Oil	700-800 mg/Nm3	40 – 50
Strakonice Czech Republic (2 units)	High Front Wall-Fired & Low Grate Fired	36-40	Lignite Brown Coal	600 mg/Nm3	50
Tekniskaverken Linkoping P1 Sweden	Stoker	275	Coal	300-350mg/Nm3 @ 4% O2	65
Trigen Cinergy St. Paul, MN	Front Wall Grate-Fired	555	Wood Waste	0.34 lb/MMBtu	56
Zachry Energy Hurt, VA	Riley Stoker	(3) 390	Wood	0.20 lb/MMBtu	46

COMPANY / LOCATION	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm)	REDUCTION %
Combustion Turbine West Coast Location	HRSG	100 MW	Gas	SCR Reagent Requirement 100 lb/hr	
Peerless Manufacturing MATEP - Boston, MA	HRSG	100 MW	Gas	SCR Reagent Requirement 2 @ 50 lb/hr	
Chemical Industry					
BP Chemicals Green Lake, TX	AOG Incin. HRSG	34	Waste Gas	330	80 +
BP Chemicals Green Lake, TX (3 incinerators)	AOG Incin. HRSG	398,757 lb/hr Flue Gas 398,757 lb/hr Flue Gas 238,361 lb/hr Flue Gas	Absorber OFF Gas	238 238 150	50 50 50
Far East Textile Taiwan	Front-Fired		Coal		50
Formosa Plastics Kaohsiung, Taiwan	Front-Fired	331	Coal	500	60
Formosa Plastics Kaohsiung, Taiwan	Front-Fired	331	Coal	500 mg/Nm3 @ 11% O2	60
Miles, Inc. Kansas City, MO	Carbon Furnace Afterburner	16	Chemical Waste	150	35
N American Chem. Corp. Trona, CA	T-Fired	(2) 75 MW	Coal	200	40
Cement Kilns					
Ash Grove Cement Seattle, WA	Cement Kiln/ Pre-Calciner	160 tons solids/hr	Coal, Gas	350 - 600#/hr	> 80
Korean Cement Dong Yang Cement, Korea	New Suspension Calciner		Coal	1.27 lb/MMBtu	45
Lehigh Portland Cement Mason City, IA	Cement Kiln/ Pre-Calciner	368	Coal, Gas	0.95-1.35 lb/MMBtu	25 - 35
Plant Name & Location Confidential				1500 mg/Nm3 @ 11% O2	45
Taiwan Cement Units #3, #5, & #6	Cement Kiln/ Pre-Calciner	260 697 658	Coal Coal Coal	1.29 1.58 0.92	50 45 25
Wulfrath Cement Germany	Cement Kiln	140	Lignite	1000 mg/Nm3 500	90

(1) All units listed are commercial installations, unless otherwise indicated. Commercial includes units in the design and installation phases.

(2) Company/Locations which are not named are requirements of Confidentiality Agreements. (D) Denotes "Demonstration."

(3) NO_x Reduction values are not necessarily the limit of the technology. These values may be the guaranteed limits.

(4) lb/MMBtu

(5) Actual limit = 0.33 lb/MMBtu

APPENDIX 2: Selected Applications of Ammonia-Based SNCR, by Industry

COMPANY/LOCATION (1)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO_x BASELINE (ppm)	REDUCTION (%) (2)
Stoker-Fired and Pulverized Coal-Fired Boilers					
Atavista, VA	Stoker Fired	2@380	Wood/Coal	321	50-65
Buena Vista	Stoker Fired	2@385	Coal	324	54-66
KMW Mainz, Germany	Pulverized Coal	2@450	Coal	600	83
Hopewell, VA	Stoker Fired	2@385	Coal	324	54-66
Modesto, CA	Stoker Fired	2@204	Tires	N/A	78
Showa Denko Oita, Japan	Pulverized Coal	1000	Coke	315	57
STEAG Herne, Germany	Pulverized Coal	4500	Coal	250	55
Coal-Fired Boilers					
Kraftwerke Mainz Wiesbaden/Deutsche Babcock Anlagen AG Germany	Cyclone	2@433	Coal		83
Northeast Utilities Merrimack Station Unit 1 Bow, New Hampshire	Cyclone		Coal		
Rio Bravo Jasmin Rio Bravo, CA	Circulating Fluid Bed	391	Coal		80
Rio Bravo Poso Rio Bravo, CA	Circulating Fluid Bed	391	Coal		80
Stockton Cogen Stockton,CA	Circulating Fluid Bed	620	Coal		N/A
Veba Kraftwerke A.G. Gelssenkirchen, Germany	Cyclone	730	Coal		38
Stoker-Fired Wood-Fueled Boilers					
Brawley, CA	Stoker Fired	250	Wood	400	60
Burney, CA	Stoker Fired	2@478	Wood	116	52
Long Beach, CA	Stoker Fired	200	Wood	325	60
Sacramento, CA	Stoker Fired	164	Wood	220	59
Shasta, CA	Stoker Fired	3@903	Wood	75-90	40-52
Susanville, CA	Stoker Fired	500	Wood	130	58
Terra Bella, CA	Stoker Fired	158	Wood	100	50
Tracy, CA	Stoker Fired	275	Wood	310	75
Circulating Fluidized and Bubbling Bed Boilers					
Chinese Station, CA	Bubbling Bed	315	Wood	125	80
Chowilla, CA	Bubbling Bed	152	Wood		
Colmac, CA	Fluidized Bed	590 total [2 units]	Coal		
Combustion Power, CA	Fluidized Bed		Coal, Coke		
El Nido, CA	Bubbling Bed	175	Wood		
Fresno, CA	Fluidized Bed	350	Wood	120	76
Jasmine, CA	Fluidized Bed	394	Coal	150	80
Madera, CA	Bubbling Bed	384	Wood		
Mendota, CA	Fluidized Bed	349	Wood	120	80
Poso, CA	Fluidized Bed	394	Coal	150	80
Rocklin, CA	Fluidized Bed	340	Wood	120	76
Stockton, CA	Fluidized Bed	620	Coal		
Woodland, CA	Fluidized Bed	330	Wood	120	76
Municiple Solid Waste Incinerators					
Commerce		300 (3)		200	60
Long Beach, CA		3@470 (3)		200	70
Stanislaus County		2@400 (3)		200	67

COMPANY/LOCATION (1)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO_x BASELINE (ppm)	REDUCTION (%) (2)
Unit "M"		750 (3)		320	65
Minneapolis		2@600 (3)		240	60
Spokane		2@400 (3)		300	45
Munich, Germany		930 (3)		190	70
Huntington, Long Island		3@480 (3)		350	60
Essex County		3@770 (3)		190	60
Bremerhaven, Germany					
Union County		3@480 (3)		350	70
Vapor, Sludge, and Hazardous Waste Incinerators					
Carson, CA		2@204	Sludge	350	65
Deepwater, NJ		2@103	Sludge	265	77
Gaviota, CA		20	Vapor	112	70
Gladstone, Australia		57	Vapor	2000	91
Germany			Vapor		
Gas- and Oil-Fired Industrial Boilers					
TSK Kawasaki, Japan		215	Oil/Gas		55
TSK Kawasaki, Japan		1135	Oil/Gas		57
TSK Kawasaki, Japan		1135	Oil/Gas		55
Mitsui Petrochemical Japan		340	Oil		53
Tonen Kawasaki, Japan		400	CO/Gas		50
Chanselor-Western Oil Santa Fe Springs, CA		50	Crude		65
Champlin Petroleum Wilmington, CA			Oil/Gas		65
Mohawk Petroleum Bakersfield, CA		[2 units]	Oil/Gas		60-70
Oxnard Refinery Oxnard, CA		18.5	Crude		30
Santa Fe Energy Santa Fe Springs, CA		3@150	Crude		
Getty Oil California			Crude		
TSK Kawasaki, Japan		574	Oil/Gas		65
Golden West Refinery Santa Fe Springs, CA		60	CO		75
Glass Melting Furnaces					
PPG Industries Fresno, CA		150	Gas		60
LOF Glass Lathrop, CA		200	Gas/Oil		51
AGF Industries Los Angeles, CA		125	Gas		61
Sierra Envr. & GAF Irwindale, CA		29	Gas		70
SHOTT Germany					
Oil- and Gas-Fired Heaters					
Tonen Kawaski, Japan		515 and 190	Gas		63
Kyokuto Petroleum Chiba, Japan		2@250	Oil/Gas		51 to 53

COMPANY/LOCATION (1)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO_x BASELINE (ppm)	REDUCTION (%) (2)
Champlin Petroleum Wilmington, CA		627 total [13 units]	Oil/Gas		50 to 60
Mohawk Petroleum Bakersfield, CA		349 total [4 units]	Oil/Gas		60 to 70
Fletcher Oil and Refining Wilmington, CA		47 total [2 units]	Gas		45 to 65
Independant Valley Energy Bakersfield, CA		165 total [4 units]	Gas		65 to 75
Chevron Research San Francisco, CA		315	Gas		69
Monsanto Carson, CA		23	Oil		43
PPG Industries Fresno, CA	Glass Furnace	150	Gas		60
LOF Glass Stockton, CA	Glass Furnace	200	Gas/Oil		51
Mendota Biomass Mendota, CA	Circ. Fluid Bed	349	Wood		72
Rocklin Rocklin, CA	Circ. Fluid Bed	340	Wood		76
Sierra Envr. and GAF Irwindale, CA	Glass Furnace	29	Gas		70
SHOTT Germany	Glass Furnace		Gas		

(1) All units listed are commercial installations, unless otherwise indicated. Commercial includes units in the design and installation phases.
(2) NO_x Reduction values are the guarantees.
(3) Tons/day.

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