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Integrated Dry NO_X/SO_2 Emissions Control System A DOE Assessment

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Executive Summary

This document is a U.S. Department of Energy (DOE) post-project assessment (PPA) of the Integrated Dry NO_x/SO_2 Emissions Control System (IDECS), a project funded under Round III of the Clean Coal Technology (CCT) Demonstration Program. The project was sited at the Public Service Company of Colorado (PSCC) Arapahoe Steam Electric Generating Station, in Denver, Colorado. The CCT Demonstration Program was created to establish the commercial feasibility of promising coal technologies that have developed beyond the proof-of-concept stage. The IDECS Project was selected to demonstrate the simultaneous reduction of nitrogen oxides (NO_x) and sulfur dioxide (SO_2) emissions from a coal-fired power plant, by installing a combination of existing and emerging technologies, which were expected to work synergistically. The major project objective was to achieve up to 70-percent reduction in NO_x and SO_2 emissions, while minimizing capital costs and producing only dry solid waste.

In March 1991, PSCC entered into a cooperative agreement with DOE to undertake this project, consisting of installing and testing the following technologies on Arapahoe Unit 4: low-NO_x burners (LNBs), overfire air (OFA), and selective noncatalytic reduction (SNCR) for NO_x control; and dry sorbent injection (DSI), both with and without flue-gas humidification (FGH), for SO_2 control. Unit 4 is a 100-MWe, down-fired boiler, designed to burn pulverized coal or natural gas. It typically operates as a load-following unit with a capacity factor of 50 to 60 percent and experiences large and rapid load swings. At the time this project was initiated, there was no low-cost NO_x and SO_2 emissions control system demonstrated for use with down-fired boilers.

The project commenced in May 1991. Operations were initiated in August 1992 and completed in December 1996. PSCC provided the host site, and the Electric Power Research Institute (EPRI) was a cofunder. PSCC provided much of the engineering, including engineering and installation of the DSI system. Other technology support included Babcock & Wilcox (B&W), supplier of the LNBs, OFA ports, and FGH equipment, and NOELL, Inc., supplier of the SNCR system. Also, Stone & Webster assisted PSCC with project engineering, Fossil Energy Research Corporation (FERCo) conducted the test program, Western Research Institute (WRI) characterized the waste materials; and Colorado School of Mines provided bench-scale testing. DOE provided 50 percent of the total project funding of $26.2 million.

The burners in Unit 4 were replaced with 12 B&W, Dual-Register Burner—Axially-Controlled Low-NO_x (DRB-XCL®), LNBs. The replacement was more complex than retrofitting a tangentially-fired or wall-fired boiler, because several boiler components had to be removed to permit the burner installation. Numerical modeling helped determine the optimum size and location for the OFA ports (B&W, dual-zone NO_x ports), a technology always used in conjunction with LNBs in this project.

The SNCR system involves the injection of urea into the furnace where the urea first decomposes into ammonia, which then reacts with NO_x to form mainly N_2, a naturally occurring inert gas. Commercial urea, received as a 65 wt% aqueous solution, was diluted to 37.5 percent after

delivery to prevent crystallization. The installation of the LNBs changed the temperature profile inside the furnace, making the original SNCR injection sites unsatisfactory during low-load operation. At low-load levels, ammonia injection was more effective than urea injection for NO_x removal. Therefore, an ammonia converter was added to convert urea into ammonia just prior to injection into the furnace. Using the converter avoided the problems associated with the storage and handling of ammonia. Advanced Retractable Injection Lances (ARILs) were installed through two unused soot blower ports to permit urea injection at the desired location in the furnace.

Dry sorbents were injected into the flue gas to control SO_2 emissions. Two identical DSI systems were installed to provide the capacity required at high sorbent-injection rates and backup at low sorbent rates. These systems can inject calcium-based sorbents into the boiler before the economizer, or they can inject sodium- or calcium-based sorbents into the flue-gas duct between the air heater and the fabric-filter dust collector (FFDC).

The purpose of FGH was to enhance the performance of DSI, but except for a few tests, FGH was only used with calcium-based DSI. The system was used to inject water into the flue gas to permit operation at a temperature approaching the adiabatic saturation temperature; the lower the approach to adiabatic saturation temperature, the more effective the calcium-based sorbent was. Water-injection lances were interspersed with the DSI lances. Shield air was supplied to help prevent deposition of solids on the nozzles, and a rapper helped remove any solids that collected.

Although PSCC's Final Report discusses the five separate technologies involved with IDECS, only three separate emission control systems were tested. The LNBs were always used in conjunction with OFA, and FGH was used only with DSI. Thus, the effects of LNB performance without OFA or FGH without DSI were not examined in the course of these tests. The three technologies (LNB/OFA, SNCR, and DSI with or without FGH) were first individually tested using both parametric tests and long-term tests. This was followed by testing the technologies as one integrated system. The tests were conducted burning low-sulfur (0.4 percent) Colorado bituminous coal, with a short test on Wyoming subbituminous (0.35-percent sulfur) coal.

Parametric testing of the LNB/OFA system was performed by setting boiler and burner parameters to specific values, operating the plant, and recording results. Long-term testing was performed by allowing the boiler to operate without interference from test personnel. Maximum OFA rate decreased as load increased, and varied from 32 percent of total secondary air at 50-MWe load to 24 percent at 80-MWe load. NO_x reductions varied from 61 percent to 69 percent. The new burners decreased the furnace-exit temperature by approximately 200 °F. This had an impact on the amount of excess air required to maintain steam temperature at reduced loads. At maximum OFA, carbon monoxide (CO) levels were lower than with the original burners and did not exceed a maximum CO level of 50 ppm. There was little difference in fly-ash loss-on-ignition (LOI) between the new burners and the old, except at a load of 50 MWe, where the fly ash produced with LNBs exhibited a higher LOI.

During long-term testing, NO_x levels were 10 to 20 percent (30 to 60 ppm) higher than during the parametric tests. This may be due to the higher O_2 levels (1 to 1.5 percent higher) detected during normal load-following conditions. NO_x levels increased by about 40 ppm for each percent increase in O_2 level.

The main variables examined in the SNCR parametric tests were boiler load, injection location, chemical type (urea, converted urea, ammonia), chemical-injection rate, and coal source. Long-term tests showed that NO_x reduction with urea was not very effective at low boiler loads, when using the original injection location. This lower than expected performance occurred because of reduced flue-gas temperature at the injection location. When aqueous ammonia was used, NO_x removal improved as boiler load decreased. SNCR achieved an additional 30- to 50-percent NO_x reduction over that achieved by the LNB/OFA system alone. Ammonia slip (ammonia in the flue gas) was about 10 ppm at the air-heater exit during base-load operation. Urea injection resulted in nitrous oxide (N_2O) emissions of 29 to 35 percent of the NO_x reduction, while injection of converted urea resulted in N_2O emissions by only 3 to 8 percent of the NO_x reduction.

An extensive series of tests was performed on the SNCR system under a variety of conditions similar to what Unit 4 would experience under normal load-following operations. The results showed that boiler load had the largest effect on system performance. The use of retractable furnace lances greatly improved the low-load performance of the SNCR system. At loads below 70 MWe, NO_x reduction increased from 11 percent with wall injectors to 35 to 52 percent with retractable lances. Some ammonia from the SNCR process adsorbed on the fly ash, the amount depending on the surface chemistry of the fly ash. With a 10-ppm slip at the dust collector inlet, ammonia concentrations in the fly ash were in the range of 100 to 200 ppm by weight.

The DSI system was tested with sodium-sesquicarbonate, sodium-bicarbonate, and hydrated-lime sorbents. Both sodium-based sorbents achieved 70-percent SO_2 removal (SO_2 removal with calcium-based sorbent was too low to be practical), however, with sodium-based DSI, some nitric oxide (NO) in the flue gas is oxidized to nitrogen dioxide (NO_2). This can produce stack-plume coloration, if the NO_2 concentration becomes too high. Sodium sesquicarbonate produced only half as much NO_2 as sodium bicarbonate.

Although the chemistry is not well understood, sodium-based DSI resulted in some NO_x reduction. At 70-percent SO_2 removal, approximately 10-percent NO_x reduction was obtained. Sodium-based DSI, when operated in conjunction with SNCR, resulted in increased ammonia adsorption on the fly ash (400 to 800 ppm). The increased sodium and ammonia concentrations could cause problems with fly-ash disposal.

Integrated-system tests consisted of combined testing of LNB/OFA ports, SNCR, and sodium-based DSI. The combined technologies integrate synergistically to control NO_x and SO_2 emissions more effectively than each technology alone. Integrated operation involved both parametric and long-term tests.

IDECS was developed to be retrofitted to boilers with pre-New Source Performance Standards (NSPS), that might require moderate (up to 70 percent) reductions in SO_2 and NO_x emissions. In particular, it was developed to meet the site-specific requirements of boilers with some of the more difficult emission-control situations. A market analysis indicated that 65 down-fired boilers (6,400 MWe total) and 29 wet-bottom boilers (3,800 MWe total) have a need for further NO_x and SO_2 reductions to meet emissions standards. Because of their age and design, these units generate high levels of NO_x, but their relatively small size and plot area makes them difficult and costly to retrofit with existing SO_2 removal technologies. IDECS provides an economic alternative to those utilities considering fuel switching or retirement for such units; however, the recent trend toward selection of technologies that provide maximum emission-removal capabilities (rather than lower removals at lower cost) may limit the market for IDECS.

An economic analysis was conducted for commercial application of IDECS. Based on the assumptions made, the capital cost for installing IDECS on a 100-MWe unit with a 65-percent operating factor (similar to Arapahoe Unit 4) is \$196/kW for the integrated system. Incremental fixed operating costs for the integrated system are \$0.22 million/yr, and variable operating costs are \$1.49 million/yr, for a total operating cost of \$1.8 million/yr. The impact of IDECS on power costs was calculated for the same power plant, with an initial (before IDECS) NO_x level of 1.15 lb/MBtu and SO_2 level of 0.66 lb/MBtu. With NO_x removals of 79 percent and SO_2 removals of 70 percent, levelized costs are \$1,358/ton of NO_x plus SO_2 removed, on a current-dollar basis, and \$1,044/ton on a constant-dollar basis. Busbar costs are 9.7 mills/kWh on a current-dollar basis and 7.4 mills/kWh on a constant-dollar basis. As plant size increases, capital and fixed costs per MWe decrease, while variable costs remain nearly level on a per-kWh basis. The overall effect is a decrease in the \$/ton of NO_x removed with increase in plant size. Increasing the plant-capacity factor increases the quantity of NO_x removed for a given capital investment.

Major conclusions from the completed project are as follows:

- LNB's plus OFA achieved up to 69-percent NO_x reduction without increasing CO levels or LOI.

- During base-load operation, urea injection achieved an additional 30- to 50-percent NO_x reduction while maintaining an ammonia slip of 10 ppm at the air-heater exit. This increased the total system NO_x reduction to greater than 80 percent at full load, exceeding the project goal of 70 percent.

- Urea injection resulted in N_2O emissions of 29 to 35 percent of the NO_x reduction. If the urea was passed through the ammonia converter before injection, N_2O emissions amounted to only 3 to 8 percent of the NO_x reduction.

- Both sodium-sesquicarbonate and sodium-bicarbonate DSI achieved 70-percent SO_2 removal, but hydrated-lime injection achieved much lower SO_2 removals. Thus, hydrated-lime injection is unlikely to be implemented on other units.

- Both sodium sesquicarbonate and sodium bicarbonate resulted in the oxidation of NO to NO_2, probably by a catalytic reaction. When compared at the same SO_2-removal rate, sodium sesquicarbonate created only half as much NO_2 as sodium bicarbonate.

- The integrated system achieved approximately 80-percent NO_x removal, 70-percent SO_2 removal, and 80-percent removal of mercury emissions.

- The integration of SNCR with sodium-based DSI decreased NO_2 emissions by approximately 50 percent compared to using sodium-based DSI without SNCR. The combination also decreased ammonia emissions to an amount below that achieved with SNCR alone, but the level was difficult to quantify. The decreased ammonia levels at the stack were accompanied by increased ammonia levels in the fly ash, causing some odor and ash-disposal concerns.

- The market for the entire IDECS system is limited, because of increasingly stringent emissions standards and the trend towards installing more expensive processes that achieve high removal levels.

I Introduction

The goal of the U.S. Department of Energy's (DOE) Clean Coal Technology (CCT) Program is to furnish the energy marketplace with a number of advanced, more efficient, and environmentally responsible coal utilization technologies through demonstration projects. These projects seek to establish the commercial feasibility of the most promising advanced coal technologies that have developed beyond the proof-of-concept stage.

This document serves as a DOE post-project assessment (PPA) of a project selected in CCT Round III, the Integrated Dry NO_x/SO_2 Emissions Control System (IDECS), as described in a Report to Congress (U.S. Department of Energy 1991). The desire to reduce emissions of nitrogen oxides (NO,nitric oxide, and NO_2, nitrogen dioxide, collectively referred to as NO_x) and sulfur dioxide (SO_2) by up to 70 percent at a minimum capital expenditure, while limiting waste production to dry solids that can be handled by conventional ash-removal equipment, prompted Public Service Company of Colorado (PSCC) to submit the proposal for the IDECS project. In March 1991, PSCC entered into a cooperative agreement with DOE to conduct the study. The project was sited at PSCC's Arapahoe Steam Electric Generating Station in Denver, Colorado. The purpose of this CCT project was to demonstrate the reduction of NO_x and SO_2 emissions by installing a combination of existing and emerging technologies, which were expected to work synergistically to reduce emissions. The technologies were low-NO_x burners (LNBS), overfire air (OFA), and selective noncatalytic reduction (SNCR) for NO_x reduction; and dry sorbent injection (DSI), both with and without flue-gas humidification (FGH), for SO_2 reduction. DOE provided 50 percent of the total project funding of $26.2 million.

The Arapahoe Station consists of four units with total nameplate generating capacity of 232 MWe. The CCT demonstration project was installed on Unit 4, a 100-MWe, down-fired unit, designed to burn pulverized coal or natural gas. Unit 4, which began operation in 1955, is used as a load-following unit and can, therefore, experience large and rapid load swings. Its usual capacity factor is 50 to 60 percent.

Construction for the demonstration project was started in May 1991 and completed in August 1992. Operations were initiated in August 1992 and completed in December 1996. The independent evaluation contained herein is based primarily on information from PSCC's Final Report (Hunt and Hanley 1997; Hunt and Hanley 1999), as well as other references (Shiomoto et al. 1992; Smith et al. 1993; Smith et al. 1994a, 1994b; Shiomoto et al. 1994; Muzio et al. 1997; Smith, Shiomoto et al. 1997a; Smith et al. 1997b, 1997c).

II Project/Technology Description

II.A Project Description

The project documentation lists five control technologies that make up IDECS: LNBs, OFA, SNCR, DSI, and FGH. However, in this project, OFA is always used in conjunction with LNBs, and FGH is used only in conjunction with DSI. The three tested technologies are (1) LNB/OFA and (2) SNCR for NO_x control, and (3) DSI plus FGH (with calcium-based sorbents) for SO_2 control. NO_x reduction occurs in the furnace, while SO_2 control is carried out in the economizer or in the ductwork, downstream of the air preheater, and in the cake that accumulates on the fabric-filter dust collector (FFDC).

PSCC managed the project and provided the host site; the Electric Power Research Institute (EPRI) was a cofunder. PSCC provided much of the engineering, including engineering and installation of the DSI system. Babcock & Wilcox (B&W) supplied the LNBs, OFA ports, and FGH equipment; and NOELL, Inc., supplied the SNCR system. Stone & Webster assisted PSCC with project engineering. Fossil Energy Research Corporation (FERCo) conducted the test program, Western Research Institute (WRI) characterized the waste materials, and the Colorado School of Mines provided bench-scale testing.

II.B Need for the Technology Demonstration

At the time this project was initiated, there was no low-cost NO_x and SO_2 emissions control system demonstrated for down-fired boilers. Thus, it was important to demonstrate that a combination of existing and emerging technologies could achieve satisfactory emissions control on a down-fired unit burning low-sulfur coal. This program establishes an alternative technology to the use of wet flue-gas desulfurization (FGD) for SO_2 control and selective catalytic reduction (SCR) for NO_x control. The extensive data gathered in this project will enable implementation of this technology on other units. Because of the nature of the technology and the manner in which it is implemented, the results should be applicable to other types of boilers besides down-fired units, particularly tangentially-fired and wall-fired units.

II.C Promise of the Technology

The major promise of LNBs was to achieve 60- to 65-percent NO_x reduction from coal-fired boilers, with SNCR providing an additional 30- to 50-percent reduction of the remaining NO_x for a total of 70 percent or more total NO_x reduction. The promise of DSI was to remove up to 70 percent of the sulfur in the flue gas, while producing only a dry waste material that could be conventionally disposed of along with the fly ash. Potential benefits include the reduction of both NO_x and SO_2, the synergistic interaction of the various technologies, and the relatively low capital investment.

II.D Project Objectives and Statement of Work

The primary objective of this project, as stated in the Cooperative Agreement, was to demonstrate an Integrated Dry NO_x/SO_2 Emissions Control System (IDECS), which could be commercialized during the 1990's and would (1) achieve significant emissions reductions of SO_2 and/or NO_x from existing facilities to minimize environmental impacts, such as transboundary and interstate pollution; and/or (2) provide for future energy needs in an environmentally acceptable manner.

The more detailed technical description states that the IDECS is a combination of subsystems which utilize several different emission-control strategies: LNBs, OFA, urea injection, dry reagent injection and FGH. The LNBs, OFA, and urea injection equipment remove NO_x. Dry reagent (sodium or calcium) injection removes SO_2, and FGH enhances the effectiveness of the calcium reagent. The goal of this project is to achieve 70-percent reductions of both NO_x and SO_2 through the integrated operation of the various technologies. Previous testing of urea and dry-sodium systems have shown that these systems may complement each other.

The statement of work (SOW) is broken down into several phases: Pre-award, Design, Procurement, Construction and Startup, and Operations. This PPA is primarily concerned with operations and will not deal with the other phases in any detail. The Operations Phase covered operation and testing of the installed systems, including the LNBs, OFA, urea injection, sodium injection, and calcium injection both with and without FGH. These systems were to be subjected to parametric tests individually, in various combinations, and as an integrated system. Originally, a short test on a high-sulfur coal was to be included, but the SOW was later amended to delete this requirement, and all operations were on low-sulfur (0.4 wt%) coal.

The SOW contains a provision to research and study the environmental impact of any new waste streams generated by the project. Various tests on the different wastes were to be performed, and if any problems were found, investigations to find solutions were to occur.

II.E Technology Description

The following sections discuss the technologies installed as part of IDECS.

II.E.1 Low-NO_x Burners

The two primary sources of NO_x, when burning fossil fuels, are thermal NO_x and fuel NO_x. Thermal NO_x is formed by the reaction of nitrogen in the combustion air with oxygen at the high temperatures existing in flames. Fuel NO_x results from the combustion of the nitrogen in the fuel. Low-NO_x burners (LNBs) reduce NO_x production by means of staged combustion, that is, they delay mixing of the fuel with all the air, so that the early stages of combustion take place at a low air/fuel ratio. This not only lowers the temperature, thus reducing thermal NO_x, but also reduces oxygen concentration so that less fuel nitrogen is converted to NO_x and more is converted to N_2. LNBs are frequently supplemented with OFA.

II.E.2 Overfire Air

OFA is air that is introduced into the furnace above the regular combustion zone (or below the regular combustion zone in the case of a down-fired boiler) to complete combustion. LNBs generally operate at a reduced air/fuel ratio. OFA is added downstream of the LNBs to reduce carbon-monoxide concentration and loss on ignition (LOI), a measure of unburned carbon in ash.

II.E.3 Selective Noncatalytic Reduction

SNCR involves the injection of a nitrogen-containing chemical, typically urea ($(NH_2)_2CO$) or ammonia (NH_3), into the combustion products at a point where the temperature is between 1,600 °F and 2,100 °F. In this temperature range and in the presence of oxygen, the chemical reacts selectively with NO_x to form N_2 (the harmless major constituent of the atmosphere) and water. Performance of SNCR systems depends strongly on furnace geometry, temperature profile, mixing, injector locations, and other factors. Furnace geometry is important, because there must be sufficient residence time within the correct temperature window. If the temperature is too low, the injected chemical does not react with NO_x, resulting in excessive emissions of ammonia. If the temperature is too high, the chemical reacts directly with oxygen to form additional NO_x. (See Figure 1.) Mixing is important, because if the injected chemical does not mix uniformly, then both incomplete reaction and excessive ammonia emissions, referred to as ammonia slip, will result.

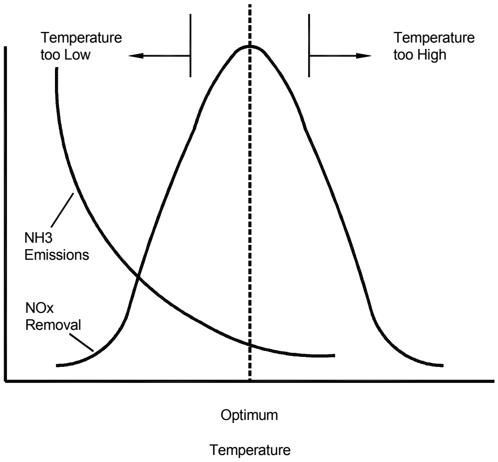


Figure 1. Temperature Window for the SNCR Process

SNCR systems typically achieve 30- to 50-percent NO_x reduction, while operating at acceptable reagent consumption and ammonia slip (typically less than 5 to 10 ppm at the stack). Since the temperature profile in a furnace changes as the load changes, multiple injection points may be required for load-following units, so that the reagent can be injected at the correct temperature zone in the furnace. The chemicals most frequently used are anhydrous ammonia, aqueous ammonia, and solutions of urea; to avoid handling ammonia, urea solutions are frequently preferred.

SNCR Process Chemistry: If ammonia is used, it reacts directly with NO_x; however, urea must first decompose. The reactions occurring in SNCR are complex and not well understood, and the following equations are only intended to be illustrative; they are not the only reactions taking place. This project used urea solution provided by Coastal Chem, Inc. As urea is heated, it decomposes according to the following reaction:

$$(NH_2)_2CO \longrightarrow NH_3 + HNCO \tag{1}$$

The ammonia then reacts to remove NO_x:

$$NH_3 + OH \longrightarrow NH_2 + H_2O \tag{2}$$
$$NH_2 + NO \longrightarrow N_2 + H_2O \tag{3}$$

The cyanic acid (HNCO) also further reacts:

$$HNCO + H \longrightarrow NH_2 + CO \tag{4}$$
$$CO + \tfrac{1}{2}O_2 \longrightarrow CO_2 \tag{5}$$

The NH_2 then reacts as shown in Equation (3). The overall reaction of urea with NO is:

$$(NH_2)_2CO + 2NO + \tfrac{1}{2}O_2 \longrightarrow 2N_2 + CO_2 + 2H_2O \tag{6}$$

However, HNCO also reacts by a different path that leads to the production of small amounts of an undesired side product, nitrous oxide (N_2O), a greenhouse gas which has an effect many times that of carbon dioxide (CO_2), the greenhouse gas present in the highest concentration in the atmosphere:

$$HNCO + OH \longrightarrow NCO + H_2O \tag{7}$$
$$NCO + NO \longrightarrow N_2O + CO \tag{8}$$

The use of urea based SNCR slightly increases the production of CO_2 due to the carbon in the urea, but this effect is quite small compared to the CO_2 generated due to coal combustion.

II.E.4 Dry Sorbent Injection

DSI systems inject dry sorbents (sodium- or calcium-based reagents) into the flue gas to control SO_2 emissions. Calcium-based sorbent may be injected either into the flue gas before the economizer or into the duct between the air heater and the particulate control device; sodium-based sorbents are injected at the latter location. The sorbents react with the SO_2 in the flue gas to form a solid that is removed by the particulate control device.

DSI systems are simple, easily retrofitted to existing units, and have low capital costs. A DSI system consists of storage facilities and equipment to convey, pulverize, and inject sorbents into the flue-gas ductwork. However, the use of DSI increases the amount of fly ash and adds soluble compounds (especially sodium-based DSI), which may prevent the fly ash from being slurried or sold as a concrete additive.

The normalized stoichiometric ratio (NSR) is used to compare the performance of sodium-based sorbents with calcium-based sorbents. For calcium-based sorbents, the NSR is defined as the number of moles of Ca injected per mole of SO_2 in the flue gas; whereas, for sodium-based sorbents, the NSR is one half the number of moles of Na injected per mole of SO_2 in the flue gas. The one half factor is necessary with Na because it takes two moles of Na to react with one mole of SO_2 but only one mole of Ca. Theoretically, an NSR of one should result in complete SO_2 removal. However, due to the reaction kinetics, not all the sorbent reacts, and sorbent utilization must also be taken into account. Percent utilization is defined as the ratio of percent SO_2 removal divided by NSR. Typically, utilization is in the range of 40 to 70 percent. Some of the factors affecting utilization are sorbent type, temperature, particle size, purity, SO_2 concentration, mixing, approach to adiabatic saturation temperature, and type of particulate control device.

Sodium-based DSI: Typically, sodium-based DSI systems inject either sodium bicarbonate ($NaHCO_3$), or sodium sesquicarbonate ($Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O$). For IDECS, nachcolite, naturally-occurring sodium bicarbonate, and trona, naturally-occurring sodium sesquicarbonate, were used. In the furnace, these reagents decompose into soda ash (Na_2CO_3), which reacts with SO_2 in both the duct and on the surface of the FFDC. Injecting soda ash directly has been found to be less effective than injecting the sorbents discussed above, possibly because of the lower surface area of the injected soda ash compared to that produced in situ. Although the reactions taking place are complex and not fully understood, the following generally represents the reactions occurring in sodium-based DSI:

$$2NaHCO_3 \longrightarrow Na_2CO_3 + H_2O + CO_2 \qquad (9)$$

$$2Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O \longrightarrow 3Na_2CO_3 + 5H_2O + CO_2 \qquad (10)$$

$$Na_2CO_3 + SO_2 + \tfrac{1}{2}O_2 \longrightarrow Na_2SO_4 + CO_2 \qquad (11)$$

In addition to reacting with SO_2, sodium-based sorbents also react with NO. Although this chemistry is not well understood, in the presence of sodium-based sorbents, a small portion of the NO is converted to NO_2. Part of this NO_2 is removed as a solid (probably as $NaNO_3$), thus resulting in reduced emissions of NO_x, but that part not removed increases the concentration of NO_2, a brownish-orange gas that can cause a visible stack plume. If this occurs, then the rate of sorbent addition may have to be decreased to reduce the NO_2 concentration.

Calcium-based DSI: The reagent used for calcium-based DSI is slaked or hydrated lime ($Ca(OH)_2$). Hydrated lime has a small enough particle size, so that it does not have to be pulverized before use. The chemistry of SO_2 capture by $Ca(OH)_2$ is not well understood, and many competing reactions are possible. Some of the more important reactions appear to be:

$$Ca(OH)_2 + SO_2 \longrightarrow CaSO_3 + H_2O \qquad (12)$$

$$Ca(OH)_2 + CO_2 \longrightarrow CaCO_3 + H_2O \tag{13}$$
$$CaCO_3 + SO_2 \longrightarrow CaSO_3 + CO_2 \tag{14}$$
$$Ca(OH)_2 \longrightarrow CaO + H_2O \tag{15}$$
$$CaSO_3 + \tfrac{1}{2}O_2 \longrightarrow CaSO_4 \tag{16}$$

The effectiveness of reagent injection into the economizer depends upon achieving good distribution at a temperature that promotes reaction with SO_2 rather than reaction with CO_2 and conversion back to calcium carbonate ($CaCO_3$). Without humidification, hydrated lime performs best at a temperature of about 1,000 °F.

II.E.5 Flue Gas Humidification

The flue-gas temperature at the outlet of the air heater is about 300 °F, too low for dry hydrated-lime to react effectively with SO_2; however, this reaction is promoted by moisture. Therefore, humidifying the flue gas enhances SO_2 capture when calcium-based sorbents are used. FGH systems inject water between the sorbent-injection grid and the particulate control device. Generally, dual-fluid nozzles are employed that use high-pressure air to atomize the injected water to ensure that it is completely evaporated before it reaches the particulate control device, to avoid damage to the duct and/or the control device. Therefore, the factor that limits the quantity of water that can be injected is the amount that will evaporate completely and remain in the vapor phase.

A measure of the moisture content of the flue gas is the approach to saturation temperature (T_{AS}). T_{AS} is given by:

$$T_{AS} = T_{FG} - T_{sat} \tag{17}$$

where, T_{FG} is the flue-gas temperature, and T_{sat} is the adiabatic saturation temperature. The smaller T_{AS} is, the closer the flue gas is to being saturated. As T_{AS} becomes smaller, SO_2 capture increases. However, incomplete mixing of injected water causes temperature gradients and localized areas of complete saturation and sets a practical limit on how low T_{AS} can be. For duct humidification, the practical limit for T_{AS} is about 20 °F. However, for a system with an FFDC, the practical limit for T_{AS} is 40 °F, because of the danger of wetting the bag filters and the resultant performance loss.

II.F Project Implementation

The Final Report (Hunt and Hanley 1999) lists five technologies that were installed for this project (see section II.D of this report). However, as actually implemented, there are really only three distinct systems, because LNBs and OFA are always used together, and humidification is used only in conjunction with DSI of a calcium-based sorbent. Technology implementation for this project is shown in Figure 2 and discussed in this section.

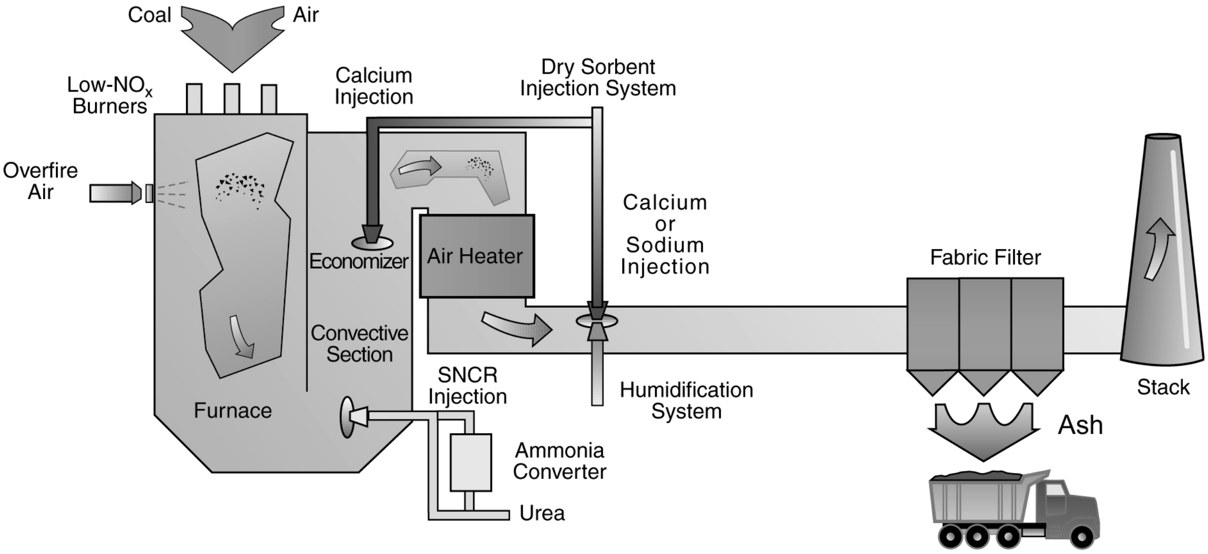


Figure 2. Simplified Process Flow Diagram of IDECS

II.F.1 Low-NO_x Burners and Overfire Air

Unit 4 has a wall that divides it into two approximately square sections. It originally had 12 intertube burners arranged in a single row along the boiler's roof, with six burners in each half. Four mills provided pulverized coal to the burners. Each mill provided fuel to three burners, with two of the burners being in one half of the furnace and one burner being in the other half. Thus, each mill provided some fuel to each half of the furnace. Retrofitting LNBs on Unit 4 was much more complex than if it had been a tangentially-fired or wall-fired boiler. The retrofit required removal of all the equipment from the boiler roof tubes to the roof of the boiler, including the windbox, coal and gas piping, and secondary air-supply duct. B&W Dual-Register Burner–Axially-Controlled Low-NO_x (DRB-XCL®) burners and B&W Dual-Zone NO_x Ports (NO_x Ports are B&W's version of OFA ports) were then installed, as discussed in the following sections.

B&W DRB–XCL® Burner: For this project, the existing burners were replaced by 12 B&W DRB-XCL® burners, arranged in four rows of three burners each. (See Figure 3.) The limited space available for the placement of the new burners caused some problems with ducting for the secondary air. Also, some modifications to the burners were necessary, since they were designed to operate horizontally and had to be changed to operate vertically.
DRB-XCL® burners use air and fuel staging to reduce the formation of NO_x. Furthermore, the air can be regulated to balance the distribution of fuel and air to each burner. This balance is important for optimizing combustion efficiency and NO_x reduction.

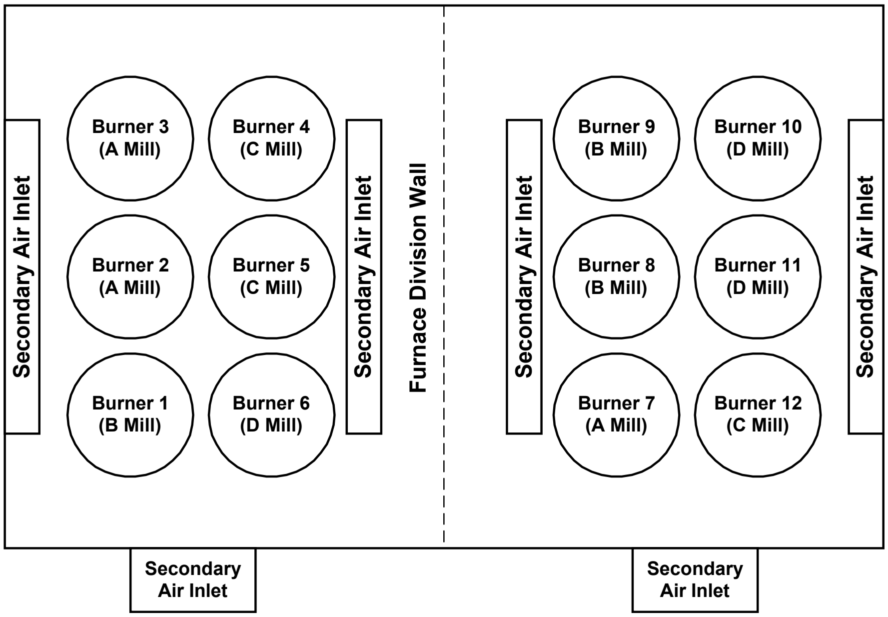


Figure 3. Plan View of Burner Arrangement after Retrofit

Figure 4 presents a schematic drawing of the B&W burners. The coal nozzle is centrally located in the burner in an arrangement that carefully limits the interaction of air and fuel in the base of the flame. The DRB-XCL® burner utilizes two air zones and multistage swirl vanes to regulate the introduction of secondary air to the fuel. A separate register controls the mix of air and fuel for each air zone. The conical diffuser and flame-stabilizing ring in the nozzle combine to improve flame stabilization, stage the burning of the fuel, and reduce NO_x emissions. The adjustable inner vanes stabilize ignition at the nozzle tip, while the adjustable outer vanes control the mixing of the remaining secondary air into the flame.

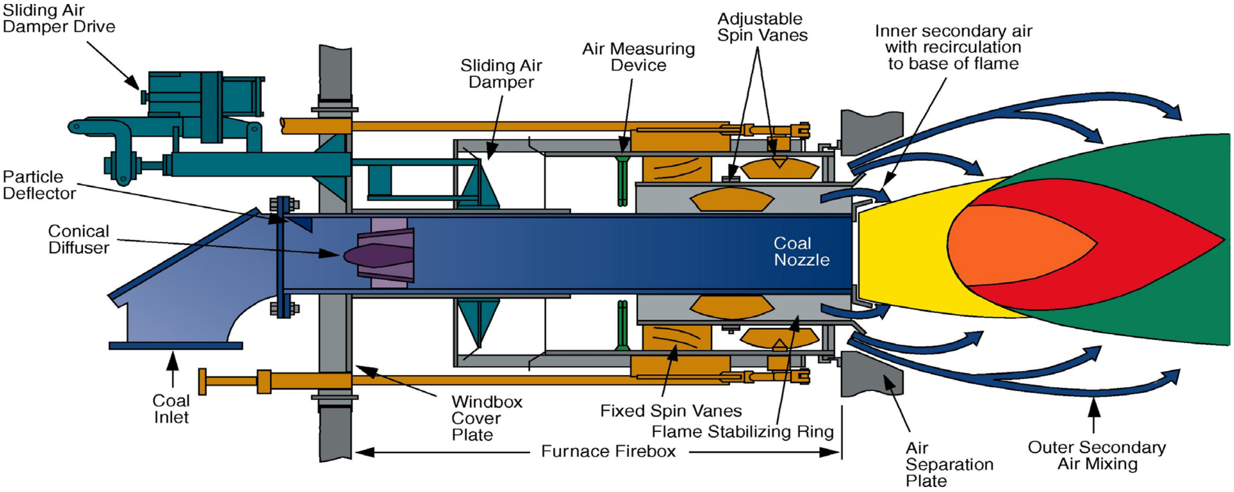


Figure 4. Schematic of B&W DRB-XCL® Burner

B&W Dual-Zone NO_x Port: Typical pulverized-coal boilers operate at 15- to 20-percent excess air. Reducing the flow of air to the burners decreases the formation of NO_x, and the greater the reduction in airflow, the greater the reduction in NO_x. As the airflow to the burners is decreased, the system requires more OFA to complete combustion. At some point, however, addition and mixing of OFA can no longer be accomplished satisfactorily, leading to increased LOI and other problems. B&W's Dual-Zone NO_x Port uses two air-distribution zones to ensure good mixing, both at the walls and in the middle of the furnace. Figure 5 is a schematic of a NO_x port. The inner-air zone is designed to produce a jet of air with sufficient axial momentum to reach across the entire furnace. The outer-air zone diverts and disperses air to the region near the NO_x port. This two-stage injection provides faster mixing and a more equal distribution of air in the furnace, thus reducing carbon monoxide (CO) and improving carbon burnout.

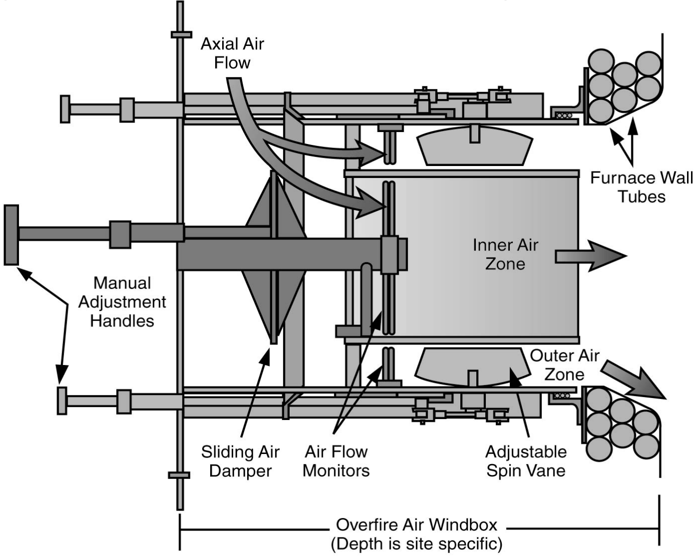


Figure 5. Schematic of B&W Dual-Zone NO_x Port

Numerical modeling was used to determine the optimum size and location for the NO_x ports, which were installed about 20 feet below the boiler roof, with three ports on the east side and three ports on the west side of the boiler. New ductwork, boiler tube panels, and windboxes were installed for the OFA ports. The B&W Dual-Zone NO_x Ports were designed to inject up to 25 percent of the secondary air.

II.F.2 Selective Noncatalytic Reduction

The SNCR system at Arapaho can be divided into four subsystems: urea receiving and storage, urea injection, ammonia conversion, and atomization.

Urea Receiving and Storage: Urea solution is stored in two 20,000 gallon tanks. Urea is received as a 65 wt% aqueous solution and was initially stored and used at this concentration. To keep the solution from crystallizing, recirculation pumps continuously circulated the solution through insulated lines with in-line heaters. To avoid the crystallization problem and eliminate the need to heat the tanks, the solution was diluted to 37.5 percent after delivery.

Urea Injection: Initially, urea injection occurred at each of two levels, through 10 injectors. (See Figure 6.) However, it was found that installation of the LNBs had changed the temperature profile in the furnace so that the temperature at the Level-2 injectors was too low for these injectors to be usable with urea. The ammonia converter improved performance at this injection location, but to overcome the problem with urea injection, NOELL's Advanced Retractable Injection Lances (ARILs) were installed through two unused sootblower ports. Each lance was about 20 feet long with a single row of nine injection nozzles on two-foot centers. A wall separates Unit 4 into east and west halves (Figure 3), each with a width of approximately 20 feet. When a lance was inserted, the first and last nozzles were one foot from the inside and outside walls. Each nozzle consisted of a fixed-air orifice and a replaceable liquid orifice. This permitted adjustments to the chemical-injection pattern along the length of the lance to compensate for maldistribution of gas flow, NO_x concentration, etc. The lances could also be rotated, providing further flexibility for urea injection.

One problem encountered was a tendency, over time, for the lances to become permanently bent, thus making their insertion and extraction difficult. A ceramic coating on the lances failed to overcome this problem. Diamond Power Specialty Company (DPSC) provided an alternative lance design that was simpler, but provided less control to balance urea injection. Although the DPSC lance operated satisfactorily, if lances are to be used for urea injection, especially on larger units, an improved design would be desirable.

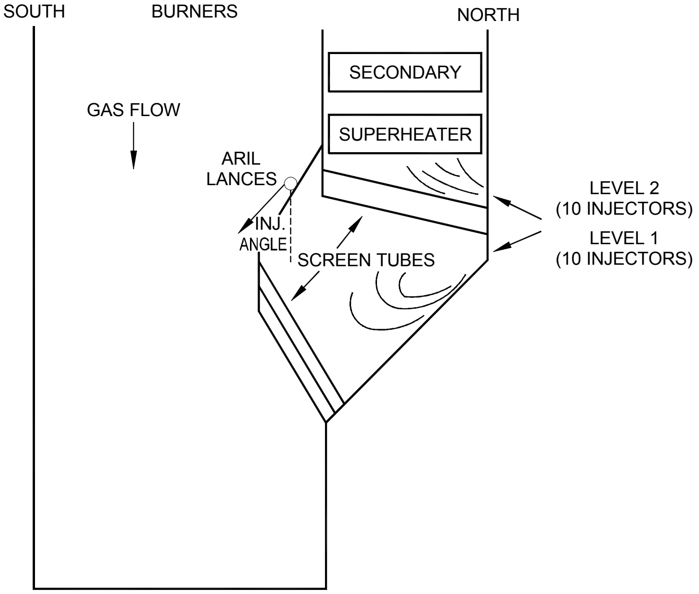


Figure 6. SNCR Injection Nozzle Locations at Arapahoe Unit 4

Ammonia Converter: An ammonia converter, provided by NOELL, was added after tests with the original burners showed that urea injection was not very effective for NO_x removal at low-load levels with reduced furnace temperatures. Ammonia injection at these conditions was more effective, since ammonia reacts more rapidly than urea at lower temperatures. However, to avoid problems with the storage and handling of ammonia, urea injection was preferred. To resolve this issue, an online conversion system to convert urea to ammonia was installed. This system first heats the urea solution and then passes it over a proprietary catalyst which decomposes the urea to ammonia and carbon dioxide, according to Equation 18:

$$(NH_2)_2CO + H_2O \longrightarrow 2NH_3 + CO_2 \tag{18}$$

A bypass valve on the converter gives the operator the option to either inject ammonia into the furnace or bypass the converter and inject urea.

Atomization: NOELL's proprietary dual-fluid injection nozzles were used to evenly distribute urea or ammonia in the boiler. A centrifugal compressor supplied up to 9,000 scfm of 4- to 12-psig air to the injection nozzles. This air helped atomize the injected solution, so that it mixed rapidly with the flue gas.

II.F.3 Dry Sorbent Injection and Flue Gas Humidification

The DSI installation was designed to operate at a hydrated-lime NSR of 2.0. Two identical DSI systems were installed on Unit 4 to provide the capacity required at high sorbent-injection rates, as well as to provide backup at lower sorbent rates. These systems had the capability to inject calcium-based sorbent into the boiler before the economizer, or sodium- or calcium-based sorbents into the flue-gas duct between the air heater and the FFDC.

Sorbent was delivered by trucks that were unloaded pneumatically into storage silos. Each of the two parallel systems had a 150-ton storage silo, enough capacity for about five days of operation. A screw feeder discharged sorbent to a pneumatic conveying system which carried the sorbent to an Entoleter pulverizer, designed to grind the sorbent to 90 percent, passing through 400 mesh. The pulverizers were bypassed when the sorbent did not need to be ground.

The piping from each pulverizer connects to a splitter located on top of the duct, upstream from the FFDC. Each splitter separates the flow into six streams which feed six injectors. The 12 injectors (six for each parallel system), which inject sorbent in the direction of flue-gas flow, form a two-by-six grid in the duct, with injectors from the two systems alternating to allow even distribution of sorbent, even if only one system is operating. Originally, some difficulty was encountered with plugging of the injection system, but equipment modifications eliminated most of the problems.

In addition to the duct-injection site, which can be used for either sodium- or calcium-based sorbent injection, calcium-based sorbent can also be injected into the superheater, referred to in the project documentation as economizer injection. It would have been desirable to mount the injectors on the front and back walls, but the construction of the furnace limited the injectors to the side walls, with four injection lances located on each side wall. Each side was fed by one of the two systems, and on each side, splitters separated the main sorbent stream into four parts.

The FGH system consisted of four subsystems: water supply (from a variable-speed pump), compressed air, injection lances, and shield air. Flue-gas temperature was monitored by a grid of 12 thermocouples in the flue-gas duct just upstream of the FFDC. To control the flue-gas temperature at the thermocouple grid, the water flowrate was controlled either manually, by setting a fixed rate, or automatically. The atomizing air system consisted of two compressors, with a combined capacity of up to 3,200 scfm at 140 psig. The water-injection lances were at the same location as the duct sorbent-injection lances and were interspersed with them. The water-injection array consisted of a grid of 84 nozzles (12 wide by 7 high) made up of 14 injection lances, each with 6 nozzles. Shield air was supplied to the lances to help prevent solids deposition on the nozzles and lances, and a rapper helped remove any collected solids.

III Technical and Environmental Assessment

This section discusses the results of the various test programs run on individual technologies and different combinations of technologies, including the integrated system. Two Colorado low-sulfur (0.4 percent) bituminous coals, Cyprus Yampa Valley and Empire Energy, were the predominant coals burned during these tests. The properties of these coals are given in Table 1.

Table 1. Properties of Test Coals

Proximate Analysis, wt%	Cyprus Yampa	Empire Energy
Moisture	10.6	13.2
Volatile Matter	34.1	33.8
Fixed Carbon	45.7	45.0
Ash	9.6	8.0
Ultimate Analysis, wt% dry		
Carbon	70.3	70.9
Hydrogen	5.0	5.2
Nitrogen	1.8	1.5
Sulfur	0.4	0.4
Oxygen	11.8	12.8
Ash	10.7	9.2
Heating Value, Btu/lb (as rec’d)	11,050	10,600

In addition, there was a short test on a Wyoming subbituminous low-sulfur (0.35 percent) coal. As part of this project, a continuous emissions monitor (CEM) was installed on Unit 4 to measure the concentrations of the following gases: NO, CO, SO_2, NO_2, CO_2, H_2O, N_2O, and NH_3. Gas samples were taken at the exit of the air preheater and downstream of the FFDC. Flyash samples were collected at the exit of the air preheater and analyzed by a FERCo LOI analyzer. Other data collected included furnace exit temperature and particulate size distribution.

III.A Technical Results

III.A.1 Low-NO_x Burners and Overfire Air

Low-NO_x burner testing was performed in two phases: parametric testing and long-term testing. The parametric testing was performed by setting boiler and burner parameters to specific values and recording results. Variables that were set included: boiler load, number of mills in service, excess air levels, and burner and OFA control settings. Long-term testing was performed by allowing the boiler to operate without interference from test personnel.

Figure 7 shows the effect of boiler load on NO_x emissions during the parametric tests. Because of the need to keep the OFA ports cool, it was not possible to operate without any OFA. The line labeled Min OFA represents 15 percent of the total secondary air. The line labeled Max OFA represents operation with the OFA dampers fully open. As air flow and fan pressure changed, OFA flow changed, resulting in decreased maximum OFA as load increased. Maximum OFA varied from 32 percent of total secondary air, at a load of 50 Mwe, to 24 percent at 80 MWe and above. NO_x reductions varied from 61 percent to 69 percent.

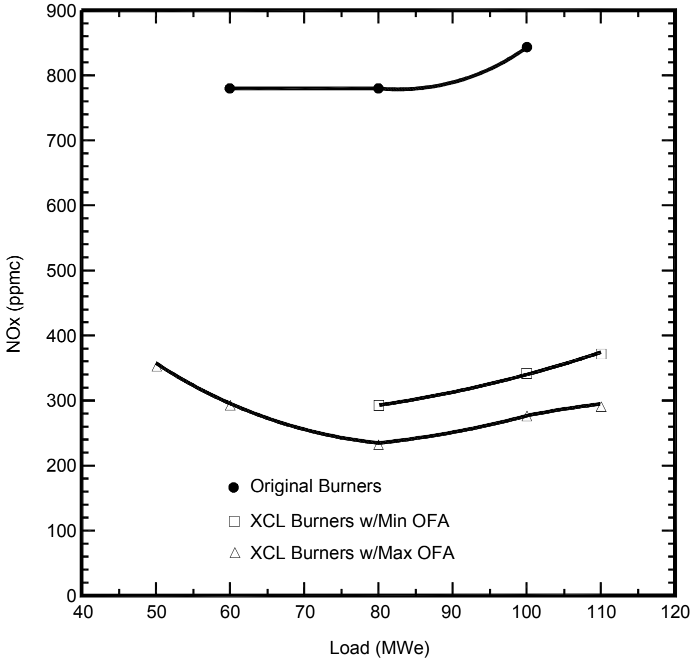


Figure 7. NO_x Emissions as a Function of Boiler Load

At maximum OFA, CO levels were lower than with the original burners. (See Figure 8.) At boiler loads below 100 MWe, the new burners required a higher excess-air level to maintain an adequate steam temperature and a maximum CO level of 50 ppm. There was little difference in fly-ash LOI between the new burners and the old, except at a load of 50 MWe, where the higher LOI may have been due to a change in operation from three mills to two. The operation of more mills appears to result in a more even distribution of coal to the burners and a finer grind, which would be expected to produce lower LOI.

The new burners resulted in an approximately 200 °F decrease in furnace exit temperature, which impacted the amount of excess air required to maintain steam temperature at reduced loads. As discussed previously, this affected the location of the SNCR temperature window and changed the point where urea was injected.

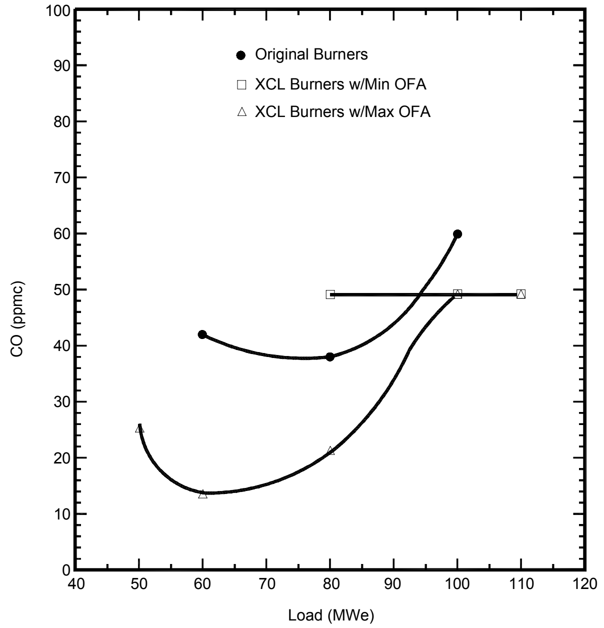


Figure 8. CO Emissions as a Function of Boiler Load

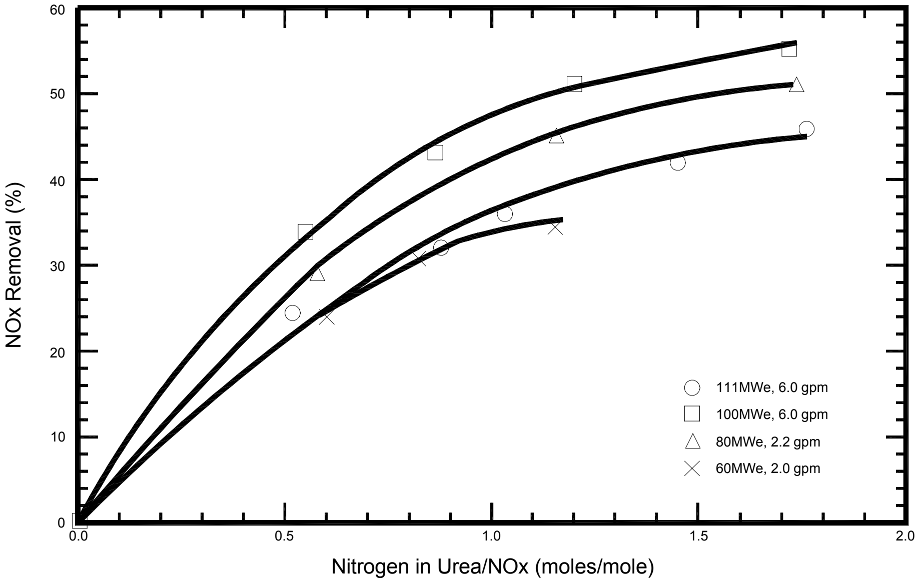
During long-term testing (November and December 1992), NO_x levels were 10 to 20 percent (30 to 60 ppm) higher than during the parametric tests. This was probably due to higher O_2 levels; O_2 levels were 1 to 1.5 percent higher during normal load following, and it was found with the new burners that NO_x levels increased about 40 ppm for each 1-percent increase in O_2 level.

III.A.2 Selective Noncatalytic Reduction

As with the LNBs, both parametric tests and a long-term test were performed with SNCR. Variables examined in the parametric tests were boiler load, SNCR-injection location, chemical used (urea, converted urea, and ammonia), SNCR chemical-injection rate, sodium sorbent-injection rate (NSR of 0 to 2.5), and coal source. The long-term test was conducted with the SNCR system operating in automatic-control mode.

Initial tests were run before the LNBs were installed. These tests indicated that NO_x reduction using urea was not very effective at low boiler loads. However, when aqueous ammonia was used, NO_x-removal efficiency actually improved as boiler load decreased. Ammonia as a reagent has approximately a 100 °F lower temperature window than urea, at least partly because a droplet of ammonia solution releases NH_3 continuously during the evaporation process, whereas a droplet of urea solution does not release any ammonia until it is completely evaporated. The better performance of ammonia at low loads led to the addition of the urea-to-ammonia converter discussed in Section II.F.2.

An extensive series of SNCR tests was run to establish the behavior of the system under a wide variety of conditions. (See Figures 9 and 10.)



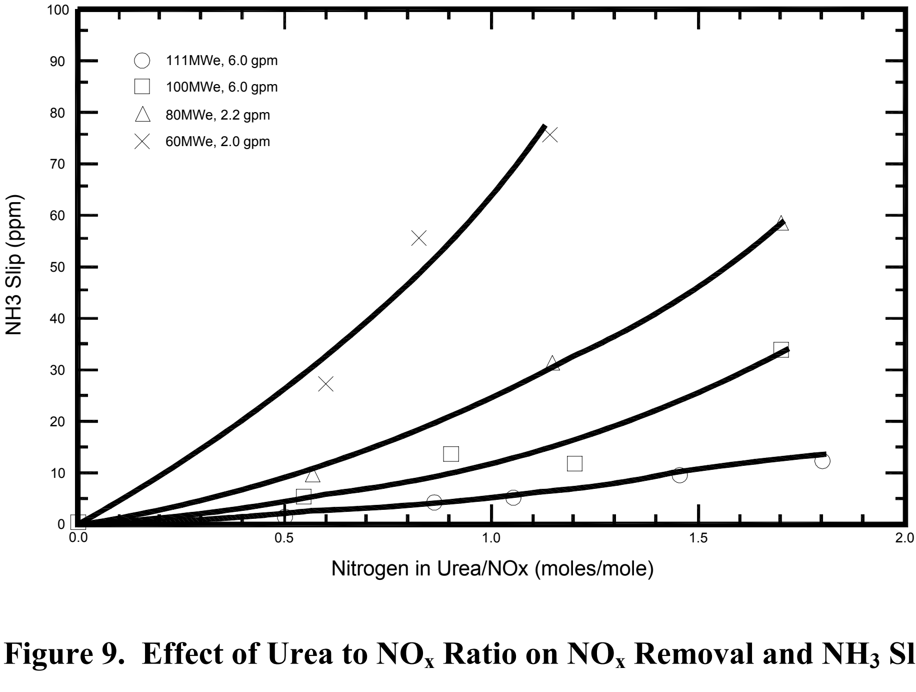
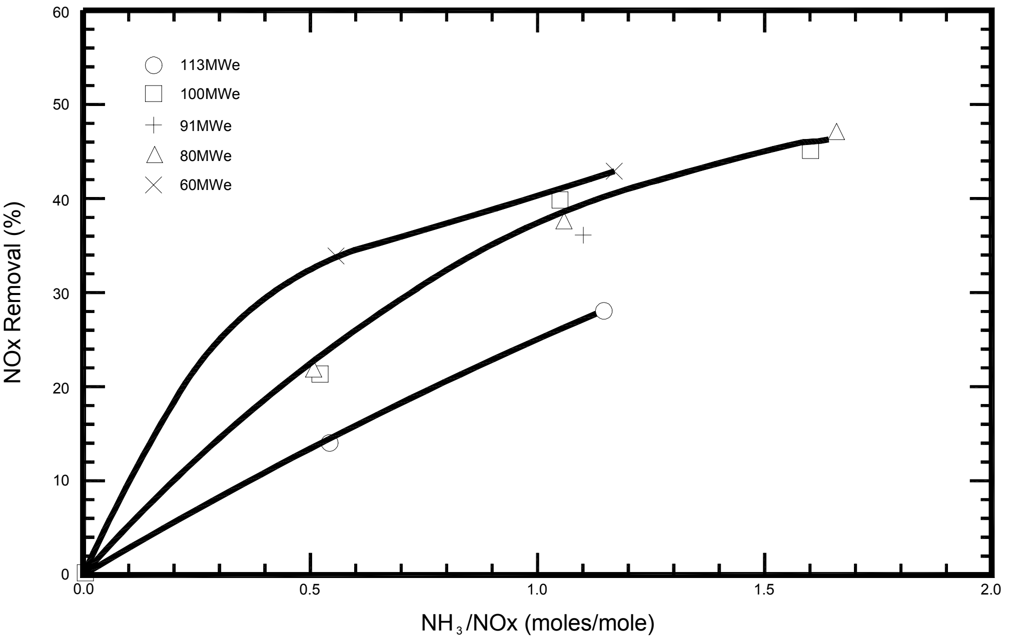


Figure 9. Effect of Urea to NO_x Ratio on NO_x Removal and NH_3 Slip



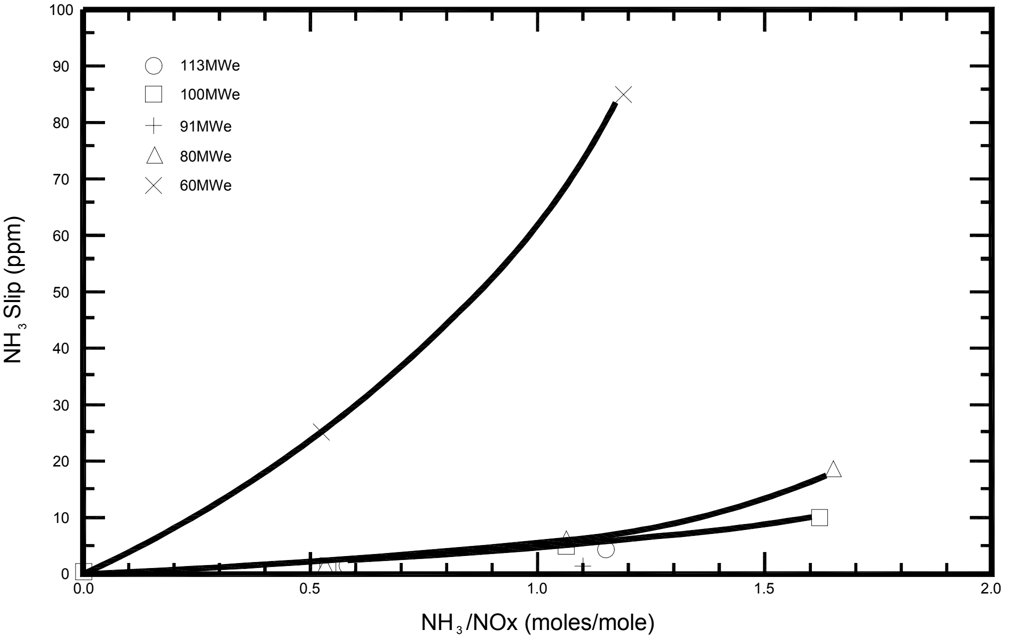


Figure 10. Effect of Ammonia to NO$_x$ Ratio on NO$_x$ Removal and NH$_3$ Slip with Urea Converter in Operation

This work was necessary to develop correlations that could be used to automatically control the SNCR facilities when Unit 4 was run under normal load-following operations. A summary of conclusions from the SNCR tests is given below.

- During base-load operation, urea injection allowed an additional 30- to 50-percent NO_x reduction while maintaining an ammonia slip of 10 ppm at the FFDC inlet. This increased the total system NO_x reduction to greater than 80 percent at full load, significantly exceeding the project goal of 70 percent.

- Boiler load was the predominate factor in determining the flue-gas temperature at the injection location, and it had the largest effect on system performance.

- Variations in the total liquid and mixing airflows had only a small effect on both NO_x reduction and ammonia emissions over the range of flows tested.

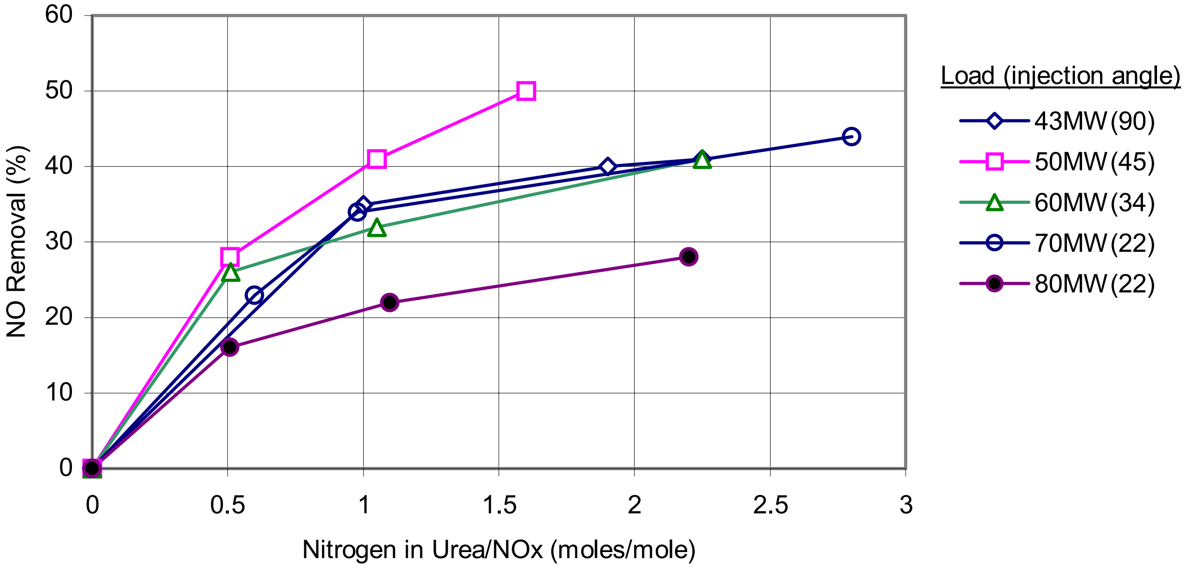
- Urea injection resulted in N_2O emissions of 29 to 35 percent of the NO_x reduction. If the urea was passed through the ammonia converter before injection, N_2O emissions amounted to only 3 to 8 percent of the NO_x reduction.

- On an equal ammonia-slip basis, converted urea provided higher NO_x removals than urea. However, the increased NO_x removal with converted urea required a higher chemical-injection rate and, thus, was less efficient.

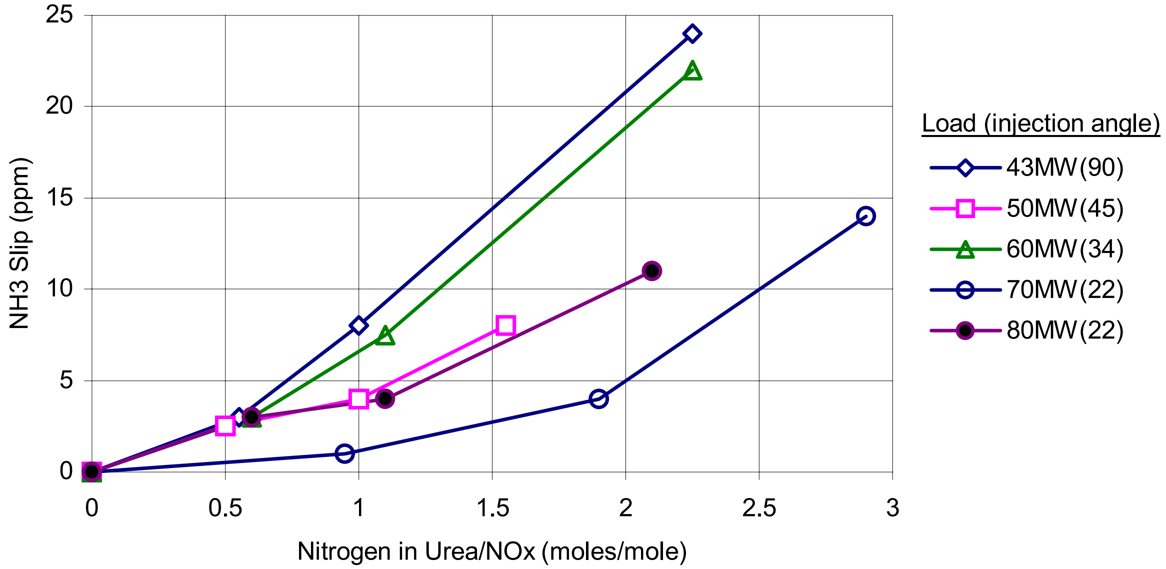
- The use of retractable furnace lances greatly improved the low-load performance of the SNCR system at Arapahoe by injecting solution in the proper temperature range. At loads below 70 MWe, NO_x reduction increased from 11 percent with the wall injectors to 35 to 52 percent with the retractable lances.

- The amount of ammonia that absorbed on the fly ash in the baghouse depended upon the fly-ash chemistry. With operation at 10 ppm ammonia slip at the FFDC inlet, ash-ammonia concentrations were in the range of 100 to 200 ppm, by weight. This level of ammonia did not cause any problems with odor or ash disposal when the SNCR was operated with the sodium-based DSI system out of service. However, as discussed in Section III.A.3., some problems were encountered when sodium-based DSI was in operation.

While the ammonia-conversion system greatly improved performance at low load, NO_x reduction was still less than at full-load operation. To permit urea injection through ports located before the boiler nose, where the flue-gas temperature was sufficient for efficient urea reactions, a pair of ARIL lances (described in section II.F.2-Urea Injection) that could be inserted into the furnace while operating at low load, were designed and installed in two unused sootblower air ports. These lances were designed to allow for rotation while inserted so that the urea could be injected into different flue-gas temperature ranges from a single boiler penetration. The ARIL lances provided greatly increased NO_x reduction at low load that allowed SNCR performance to remain relatively uniform over the normal operating load range of Arapahoe Unit 4. (See Figure 11.)



(a) NO Removal



(b) NH_3 Emissions

Figure 11. Effect of Urea to NO_x Ratio on NO_x Removal and NH_3 Slip with ARIL Lances in Use

III.A.3 Dry Sorbent Injection

The DSI system was operated both with sodium-based sorbents and with calcium-based sorbents. These tests are discussed in the following sections.

Sodium-based Sorbents: While the primary purpose of dry sorbent injection is SO_2 removal, with sodium-based sorbents a small reduction in NO_x also occurs. The objective of the sodium-based dry sorbent test program was to develop performance data with respect to SO_2 removal, NO_x removal, and NO_2 emissions with sodium-sesquicarbonate and sodium-bicarbonate injection and to demonstrate the long-term performance of the system. For most tests, the sorbent was injected just downstream of the air preheater, but a few tests were conducted with injection at a higher temperature location before the air preheater. The primary variables investigated were NSR, sorbent type, and boiler load. Humidification was briefly tested during sodium-sesquicarbonate injection, with the primary variable being the approach to adiabatic saturation temperature. Both short-term parametric tests and long-term tests were performed. Properties of the two sodium-based sorbents that were tested are given in Table 2.

Table 2. Properties of Sodium-Based Sorbents

Sorbent	Sodium Sesquicarbonate	Sodium Bicarbonate
Formula	$NaHCO_3•Na_2CO_3•2H_2O$	$NaHCO_3$
Supplier	Solvay Minerals, Inc.	NaTec Resources, Inc.
Composition		
Na_2CO_3	48.5 wt%	-----
$NaHCO_3$	36.3 wt%	99.5 wt%
Na	29.8 wt%	27.2 wt%
Bulk Density	49 lb/ft^3	64 lb/ft^3
Mass Mean Diameter		
As Received	27.8 µm	61.5 µm
Pulverized	17.0 µm	18.8-24.3 µm

With the low sulfur coal fired at the Arapahoe Station, sodium-based DSI had a higher SO_2-removal efficiency than calcium-based DSI. A summary of test findings is presented below:

- Both sodium-sesquicarbonate and sodium-bicarbonate DSI achieved steady-state SO_2 removals of 70 percent. The time to reach steady-state with sodium-bicarbonate injection into 220- to 280-°F flue gas before the FFDC was slow. However, when injected before the air heater at 650^oF, SO_2 removal with sodium-bicarbonate injection reached steady-state much more rapidly with good reagent utilization.

- When injected before the fabric filter, sodium-sesquicarbonate injection worked well over the tested flue-gas temperature range of 220 to 280 °F. (See Figure 11.) The same steady-state SO_2 removal that was achieved with injection before the fabric filter was also achieved with injection before the air heater at 650 °F.

- At 70-percent SO_2 removal, sodium-bicarbonate injection before the air preheater required an NSR of approximately 1.0, while sodium-sesquicarbonate injection before the FFDC required an NSR of approximately 1.9. (See Figure 12.) As the SO_2-removal level decreases, the NSR ratio between the two reagents decreases rapidly.

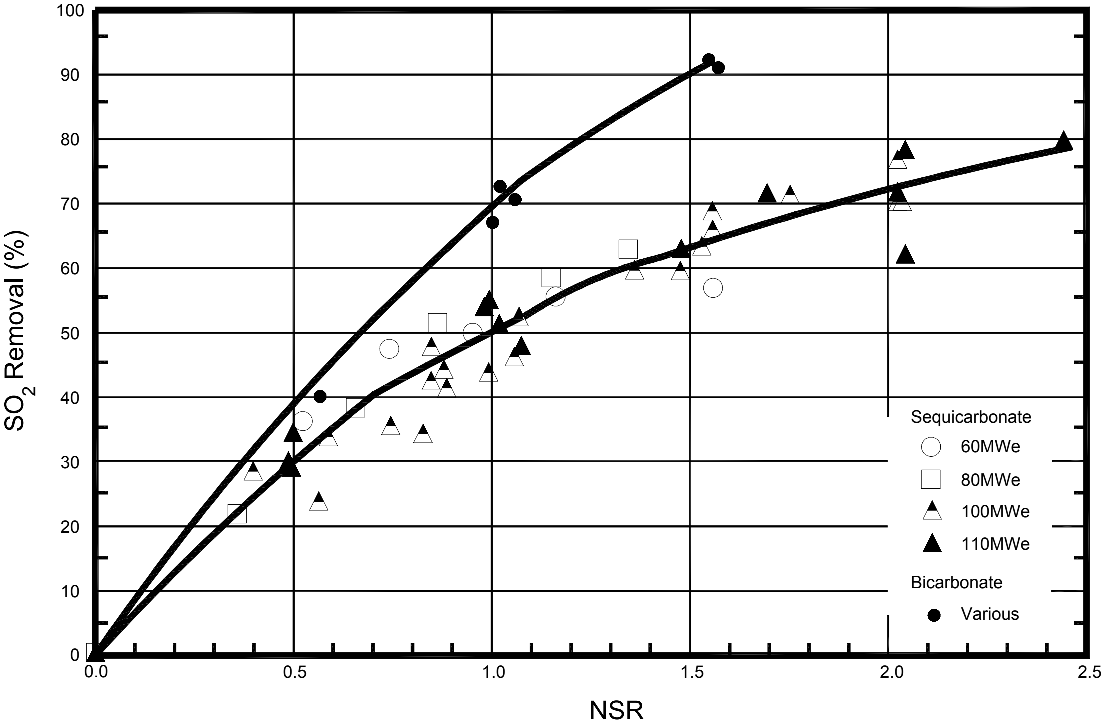


Figure 12. Effect of NSR on SO_2 Removal for Injection of Sodium Sesquicarbonate Before the FFDC

- SO_2-removal efficiency with sodium sesquicarbonate increases substantially as particle size is reduced. At an NSR of 0.9, a 28-µm mean diameter achieved 28-percent SO_2 removal, a 17-µm mean diameter achieved 42-percent SO_2 removal, and a 15-µm mean diameter achieved 48-percent SO_2 removal. SO_2-removal efficiency with sodium bicarbonate showed less dependence upon particle size. At an NSR of 0.9, a 25-µm mean diameter achieved 58-percent SO_2 removal, while an 18-µm mean diameter achieved 60-percent SO_2 removal.

- Humidification of the flue gas to a 60 °F approach to saturation temperature increased SO_2 removal by up to 20 percent, when injecting sodium sesquicarbonate at an NSR of 2.0. At an NSR of 1.0, humidification had little effect.

- Boiler load had little, if any, effect on the required chemical-injection rate for either sodium sesquicarbonate or sodium bicarbonate.

- Some NO_x reduction is associated with both sodium-sesquicarbonate and sodium-bicarbonate DSI. At 70-percent SO_2 removal, approximately 10-percent NO_x reduction is obtained with either reagent, but the amount of NO_x reduction varied for unknown reasons and could not be controlled.

- Both sodium sesquicarbonate and sodium bicarbonate result in the oxidation of NO to NO_2, probably due to some form of catalysis. When compared at the same SO_2-removal rate, sodium sesquicarbonate produced only half as much NO_2 as sodium bicarbonate.

Calcium-based Sorbents: As with the other systems discussed above, both short-term parametric tests and long-term tests were performed with calcium-based sorbent injection. The properties of the sorbent used are given in Table 3.

Table 3. Properties of Hydrated-lime Sorbent

Sorbent	Hydrated Lime
Formula	$Ca(OH)_2$
CaO Content	68 wt%
Mass Mean Diameter	2.67 µm
BET Surface Area	14.8 m^2/g

The primary parameters which control SO_2 removal with calcium-hydroxide ($Ca(OH)_2$) injection and FGH are the NSR of the injected sorbent and the approach to adiabatic saturation temperature. (See Figure 13.) Hydrated lime was injected at two locations: into the boiler, where the temperature was 1000 °F, and after the air preheater, where the temperature was 250 °F . Results from these tests are summarized below.

- The highest SO_2 removal was obtained with duct injection with humidification to an approach to saturation temperature of 25 to 30 °F. (See Figure 12.) At an NSR of 2, SO_2 removal ranged from 28 to 40 percent.

- The majority of the SO_2 removal occurred during the entrained phase before the water was evaporated. At most, 5 percent of the overall reduction occurred on the fabric filter.

- Some ash buildup occurred in the duct during humidification, although PSCC indicates that this should be manageable.

- Only 5- to 10-percent SO_2 removal was obtained with hydrated-lime injection before the economizer at a flue-gas temperature of 950 to 1150 °F and an NSR of 2. Poor reagent distribution was probably a major cause of the poor performance. Sampling across a traverse of the flue gas at the boiler outlet showed that, even at points near the wall, where the local NSR was estimated at 6.0, only 30-percent SO_2 removal was obtained.

- Humidification during economizer injection of hydrated lime did not significantly improve SO_2 removal. A significant amount of the injected hydrated lime reacted with CO_2 to form calcium carbonate ($CaCO_3$).
- In general, SO_2 removal with hydrated lime was substantially less than expected, and the goal of 50-percent removal was not met.

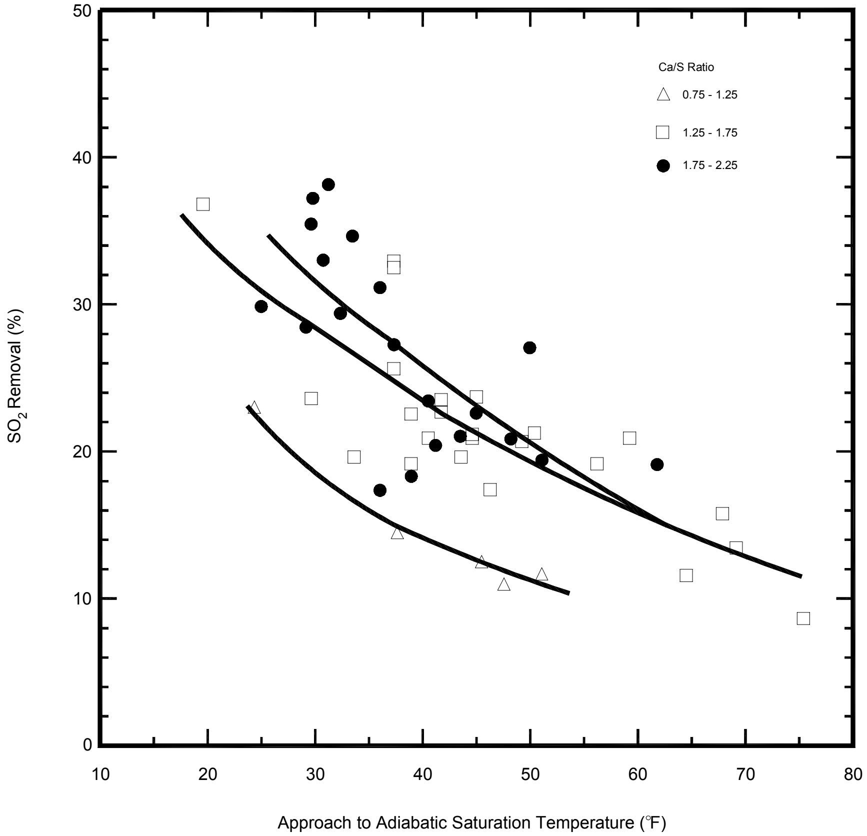


Figure 13. Effect of Approach to Adiabatic Saturation Temperature on SO_2 Removal with Calcium Hydroxide Injection

III.A.4 Integrated System

The integrated system consisted of LNBs/OFA, SNCR, and sodium-based DSI. It was expected that the combined technologies would integrate synergistically to control NO_x and SO_2 emissions more effectively than if each technology were used alone. Integrated operation involved both parametric and long-term tests. Following are conclusions from these tests.

- The integrated system achieved 80-percent NO_x removal and 70-percent SO_2 removal.
- The integration of SNCR with sodium-based DSI decreased by approximately 50 percent of the level of NO_2 emissions that occur when sodium-based DSI is used without SNCR.
- The integration of sodium-based DSI and SNCR decreased the level of ammonia emissions that occur with SNCR alone, although the effect was difficult to quantify. From results of the long-term tests, it is estimated that a 50-percent reduction occurred in ammonia slip when operating the sodium injection system at 70-percent SO_2 removal. Interpreting results was difficult because, as ammonia emissions were reduced, the control system automatically increased the urea injection rate to provide for higher NO_x reductions at the same ammonia slip. Conversely, the ammonia slip could be reduced by 50 percent while maintaining the same NO_x removal. These estimates take into account the approximately 10-percent NO_x removal that the sodium-based injection system provided.
- For a given type of ammonia slip, fly-ash ammonia absorption increased with integrated operation of sodium-based DSI and SNCR, compared to SNCR alone. At 8 ppm ammonia slip, fly-ash ammonia ranged from 400 to700 ppm versus 100 to 200 ppm with SNCR alone. One benefit of integrated operation is that, at conditions resulting in reduced ammonia slip, the urea injection rate can be increased to provide higher NO_x reduction without increasing ammonia slip. Reducing the ammonia slip to 4 ppm reduced the ammonia concentration in the ash to the 100- to 200-ppm range that occurred with SNCR alone.
- With the integrated system, the ammonia odor in the ash truck-loading area increased and became a concern. When the fly ash was wetted to control fugitive dust emissions, the rapid pH change that occurred due to sodium injection caused a more rapid release of the absorbed ammonia. This problem was solved by transporting the ash in enclosed tanker trucks, and by not adding water at the site.

III.B Environmental Performance

The IDECS project was designed to comply with all applicable federal and state air, water, and solid-waste regulations. Operation of this CCT demonstration project did not increase the volume or composition of plant emissions, except for the following: CO_2-emission levels increased very slightly due to the decomposition of injected urea, and total fly-ash quantities increased slightly due to DSI. SO_2- and NO_x-emission levels decreased significantly. No problem areas were identified concerning environmental regulations or permit conditions due to operation of the IDECS project.

Calcium-based DSI plus humidification did not perform satisfactorily and is not likely to be implemented on any other units. Therefore, there is no need to discuss the effects of calcium-based DSI on environmental performance.

There are some potentially undesirable side effects when using sodium-based DSI with the integrated system. With sodium-based DSI, some NO in the flue gas is oxidized to NO_2. If the concentration is high enough, coloration of the stack plume can result. Also, sodium-based DSI results in additional NH_3 adsorption on the ash, which may prevent the ash from being slurried or sold as a concrete additive. With increased fly-ash NH_3 levels, the ammonia odor in the ash truck-loading area increases (when the fly ash is wetted to control fugitive dust), and may also result in a pollution problem when landfilling the ash. Any replication of the IDECS technology must take these factors into account.

The IDECS project included a comprehensive investigation into many potential air-toxic emissions. Four separate air-toxics tests were completed: (1) low NO_x combustion, (2) SNCR, (3) DSI using calcium-based reagent, and (4) DSI using sodium-based reagent. The detailed findings of the air-toxics tests are documented in the Appendices to the Final Report (Hunt and Hanley 1999). Tests show that the use of a FFDC for particulate control was very effective for controlling nearly all air toxic emissions. Overall particulate removal was greater than 99.9 percent, and the average trace-metal-emission removal was over 96.9 percent. Mercury removal was higher than expected and very near the detection limit.

IV Market Analysis

IV.A Market Size

IDECS consists of the integration of several technologies that were in various stages of commercialization at the time this project was initiated. PSCC developed and owns the rights (in the form of an issued U.S. patent) to the integration and concurrent use of sodium-based dry sorbent injection and SNCR. B&W developed and owns the rights to the low-NO_x burners (LNBs), the NO_x ports, and the duct humidification technologies. SNCR is being marketed by NOELL and other vendors, with certain proprietary aspects to the different versions of this technology. DSI is public domain technology, although there may be proprietary aspects to some versions.

IDECS was developed as a retrofit application for pre-NSPS boilers that might require up to 70-percent reductions in SO_2 and NO_x emissions. In particular, it was developed to meet the site-specific requirements for some of the more difficult boiler emission-control situations. A market analysis indicated that the following units have the need for further NO_x and SO_2 reductions.

- 65 down-fired boilers (6,400 MWe total)
- 29 wet-bottom boilers (3,800 MWe total)

Because of their age and design, these units generate high levels of NO_x and because of lack of plot area, they are difficult to retrofit with existing SO_2 removal technologies. They also tend to be relatively small. As a result of these considerations, utilities will be very sensitive to capital costs for new equipment for these units. Many utilities are considering fuel switching or retirement; however, IDECS provides an economic alternative that can extend their lives.

The Final Report (Hunt and Hanley. 1999) discusses a “secondary market,” which includes applications for some, but not all, of the technologies making up the integrated IDECS package. Because partial application would not incorporate the synergies inherent in the combined system, and the primary objective of the project was to demonstrate the benefits of the integrated IDECS system, this PPA does not include an evaluation of this “secondary market.”

The recent trend is toward technologies that provide maximum removal capabilities, rather than selection of technologies that achieve lower removals, but at a more economical cost. This trend may limit the market for IDECS. Nevertheless, there are still a number of units that would benefit from IDECS, especially units that can use emissions averaging to meet emissions limits.

PSCC intends to continue market exposure of IDECS in those cases where the benefits of the system can be maximized. PSCC is studying the potential of installing all or parts of IDECS on a number of its units, but applicability may be relatively limited, based on recent strict environmental requirements. B&W has a large market share in the environmental-control industry and is exposing potential customers to IDECS, when it meets specific requirements for cost and contaminant-removal levels.

IV.B Economics

An economic analysis for commercial application of IDECS on a generic 100-MWe power plant was performed, based on the values of the economic parameters shown in Table 4. However, when estimating costs for a particular installation, scope adjustments and site-specific factors (such as unit size, number of spares kept on site, design coal properties, space availability, and necessary furnace penetrations) need to be taken into account. The most likely initial application of this technology will be to retrofit existing power stations. IDECS is generally intended for smaller units; therefore, economics for this project were determined for a 100-MWe unit (instead of the usual 300-Mwe unit). Because of the relatively small unit size, the cost of removal of pollutants on a $/ton basis is increased. The economics are based on the assumption that the technologies are mature and incorporate experience gained from this demonstration.

Table 4. Economic Parameters Used in IDECS Economic Evaluations

Cost of Debt, %	8.5
Dividend Rate for Preferred Stock, %	7.0
Dividend Rate for Common Stock, %	7.5
Debt/Total Capital, %	50.0
Preferred Stock/Total Capital, %	15.0
Common Stock/Total Capital, %	35.0
Income Tax Rate, %	38.0
Investment Tax Credit, %	0.0
Property Tax & Insurance, %	3.0
Inflation Rate, %	4.0
Discount Rate (with Inflation), %	7.925
Discount Rate (without Inflation), %	3.744
Escalation of Raw Materials above Inflation, %	0.0
Construction Period, Years	1
Allowance for Funds Used During Construction, %	0.0
Remaining Life of Power Plant, Years	15
Year for Costs Presented in this Report	1994
Royalty Allowance, % of Total Capital	0.5
Capital Charge Factor - Current Dollars	0.160
- Constant Dollars	.124
O&M Levelization Factor - Current Dollars	1.314
- Constant Dollars	1.000
Power Plant Capacity Factor, %	65
Sales Tax Rate, %	5.0
Cost of Freight for Process Equipment, %	2.0
General Facilities, % of Total Process Capital	10.0
Engineering and Home Office, % of Total Process Capital	10.0

IV.B.1 Capital Cost

Capital costs for installing IDECS on a 100 MWe unit with a 65-percent operating factor similar to Arapahoe Unit 4 are given in Table 5. This table shows that the cost of calcium-based DSI plus humidification is much higher than sodium-based DSI, and since sulfur-removal efficiency is much lower for the calcium-based system, calcium-based DSI does not look attractive. Therefore, the integrated system used in this cost analysis consisted of LNBs with OFA, SNCR, and sodium-bicarbonate based DSI. Capital costs in 1994 dollars for LNBs with OFA are \$129/kW, \$42/kW for SNCR, and \$25/kW for DSI, which gives a total of \$196/kW for the integrated system. These are reasonable costs for a combined NO_x/SO_2 control system.

IV.B.2 Operating Cost

Operating costs for IDECS (LNBs, SNCR, and sodium-bicarbonate DSI) on a 100 MWe power plant are shown in Table 6. The costs shown are only the incremental costs resulting from installation of IDECS. Fixed operating costs are \$0.32 million/yr, and variable operating costs are \$1.49 million/yr, for a total operating cost of \$1.8 million/yr.

IV.B.3 Economics

The impact of IDECS on power costs is shown in Table 7. The analysis was conducted for a 100 MWe power plant operating at a 65-percent capacity factor with an initial (before IDECS) NO_x level of 1.15 lb/MBtu and SO_2 level of 0.66 lb/MBtu. NO_x removal is 79 percent , and SO_2 removal is 70 percent . Costs are levelized both on a current-dollar and constant-dollar basis. Levelized costs are \$1,358/ton of NO_x plus SO_2 removed on a current-dollar basis and \$1,044/ton on a constant-dollar basis. Busbar costs are 9.7 mills/kWh on a current-dollar basis and 7.4 mills/kWh on a constant-dollar basis.

Additional economic analyses were performed to determine the impact of various parameters on economics. The result of these analyses, which were performed on a constant-dollar basis, are show in Table 8.

As plant size increases, capital and fixed costs per MWe decrease, while variable costs stay about the same on a per MWe basis. The overall effect is a decrease in the \$/ton of NO_x plus SO_2 removed as the plant size increases. As capacity factor increases, the \$/ton of pollutant removed decreases. Since the capital costs are fixed, increasing the capacity factor increases the quantity of NO_x removed for a given capital investment. Costs are also sensitive to initial NO_x level. At a fixed percentage level of reduction, as the initial NO_x level decreases, the absolute quantity of NO_x removed also decreases, and the \$/ton of NO_x removed increases.

Table 5. Capital Costs for Installing the Integrated Dry NO_x/SO_2 Emissions Control System 100-MWe Unit, 65% Operating Factor (1994 dollars)

	Low-NO_x Combustion System		SNCR[a]		Sodium-Based DSI[b]		Calcium-based DSI Plus Flue Gas Humidification[c]		Integrated[d]	
	$\$10^6$	\$/kW	$\$10^6$	\$/kW	$\$10^6$	\$/kW	$\$10^6$	\$/kW	$\$10^6$	\$/kW
Installed Equipment Cost	6.65	66.55	2.73	27.32	1.68	16.81	3.13	31.31	11.06	110.68
Process Contingency	0.67	6.65	0.27	2.73	0.17	1.68	0.31	3.13	1.11	11.06
Total Process Capital	7.32	73.20	3.00	30.05	1.85	18.49	3.44	34.44	12.17	121.74
Engineering and Home Office	0.73	7.32	0.30	3.00	0.19	1.85	0.34	3.44	1.22	12.17
Project Contingency	0.40	4.03	0.17	1.65	0.10	1.02	0.19	1.90	0.67	6.70
Total Plant Investment	8.45	84.55	3.47	34.70	2.14	21.36	3.97	39.78	14.06	140.61
Royalty Allowance	0.04	0.37	0.02	0.15	0.01	0.10	0.02	0.20	0.07	0.62
Preproduction Costs	0.00	0.03	0.02	0.22	0.05	0.45	0.04	0.40	0.07	0.70
Inventory Capital	0.00	0.00	0.07	.74	0.17	1.72	0.14	1.40	0.24	2.46
Subtotal Capital	8.49	84.95	3.58	35.81	2.37	23.63	4.17	41.78	14.44	144.39
Cost of Construction Downtime[e]	4.37	43.68	0.55	5.46	0.16	1.56	0.16	1.60	5.08	50.70
Total Capital Requirement	12.86	128.63	4.13	41.27	2.53	25.19	4.33	43.38	19.52	195.09

[a] 0.4 lb NO_x/MBtu, 40% NO_x removal

[b] 0.4% sulfur coal, 70% SO_2 removal, sodium bicarbonate (for sodium-sesquicarbonate sorbent, there is an insignificant increase in inventory)

[c] 0.4 % sulfur coal, 15% SO_2 removal, hydrated-lime sorbent

[d] Integrated system consists of low-NO_x combustion system, SNCR, and sodium-bicarbonate DSI; precontrol NO_x of 1.15 lb/MBtu, 79% NO_x removal; precontrol SO_2 of 0.66 lb /MBtu, 70% SO_2 removal

[e] Based on a cost of replacement power of \$0.05/kWh

Table 6. Operating Costs for the Integrated Dry NO_x/SO_2 Emissions Control System 100-MWe Unit, 65% Operating Factor

	Low-NO_x Combustion System	SNCR[a]	Sodium-Based DSI[b]		Calcium-Based DSI Plus Flue Gas Humidification[c]	Integrated[d]
			Bicarbonate	Sesquicarbonate		
	$\$10^3$/yr	$\$10^3$/yr	$\$10^3$/yr	$\$10^3$/yr	$\$10^3$/yr	$\$10^3$/yr
Fixed O&M Costs						
Operating Labor	0.0	33.6	33.6	33.6	33.6	67.2
Maintenance Labor	29.3	24.0	29.6	29.6	55.4	82.9
Maintenance Material	43.9	36.1	44.4	44.4	83.0	124.4
Administration/Support Labor	8.8	17.3	19.0	19.0	26.7	45.1
Fixed Costs	82.0	111.0	126.6	126.6	198.7	319.6
Variable Operating Costs						
Urea	0.0	365.6	0.0	0.0	0.0	365.6
Sorbent	0.0	0.0	956.2	854.2	464.7	956.2
Water	0.0	1.8	0.0	0.0	0.2	1.8
Waste Disposal	0.0	0.0	68.2	122.7	63.5	68.2
Electric Power[e]	0.3	80.6	20.6	20.6	322.8	101.5
Variable Costs	0.3	448.0	1045.0	997.5	851.2	1493.3
Total O&M Cost	82.3	559.0	1171.6	1124.1	1049.9	1812.9

[a] 0.4 lb NO_x/MBtu , 40% NO_x removal

[b] 0.4% sulfur coal, 70% SO_2 removal

[c] 0.4% sulfur coal, 30% SO_2 removal, hydrated-lime sorbent

[d] Integrated system consists of low-NO_x combustion system, SNCR, and sodium-bicarbonate DSI; precontrol NO_x of 1.15 lb/MBtu, 79% NO_x removal; precontrol SO_2 of 0.66 lb /MBtu, 70% SO_2 removal

[e] Based on a cost of power of \$0.05/kWh

Table 7. Economics of the Integrated Dry NO_x/SO_2 Emissions Control System 100-MWe Unit, 65% Operating Factor

	Low-NO_x Combustion System[a]		SNCR[b]		Sodium-Based DSI[c]		Calcium-based DSI Plus Flue Gas Humidification[d]		Integrated[e]	
Levelized Cost of Power, mills/kWh	Current $	Constant $	Current $	Constant $	Current $	Constant $	Current $	Constant $	Current $	Constant $
Capital Charge	3.62	2.80	1.16	0.90	0.71	0.55	1.22	0.94	5.48	4.25
Fixed O&M Cost	0.19	0.14	0.26	0.20	0.29	0.22	0.46	0.35	0.74	0.56
Variable Operating Cost	0.00	0.00	1.04	0.79	2.41	1.83	1.96	1.50	3.45	2.62
Total Cost	3.81	2.94	2.46	1.89	3.41	2.60	3.64	2.79	9.67	7.43
Levelized Cost, $/ton NO_x/SO_2 removed Basis	NO_x		NO_x		SO_2		SO_2		$NO_x + SO_2$	
Capital Charge	918	711	1376	1066	303	235	1216	942	770	597
Fixed O&M Cost	48	37	304	231	125	95	456	347	104	79
Variable Operating Cost	0	0	1228	935	1032	785	1961	1493	484	369
Total Cost	966	748	2907	2232	1460	1115	3633	2782	1358	1044

[a] Initial NO_x rate = 1.15 lb/MBtu; NO_x removal = 65%

[b] Initial NO_x rate = 0.40 lb/MBtu; NO_x removal = 40%

[c] Initial SO_2 rate = 0.66 lb/MBtu; SO_2 removal = 70%; sodium-bicarbonate sorbent

[d] Initial SO_2 rate = 0.66 lb/MBtu; SO_2 removal = 30%; hydrated-lime sorbent

[e] Integrated system consists of low-NO_x combustion system, SNCR, and sodium-bicarbonate DSI. Initial NO_x rate = 1.15 lb/MBtu; NO_x removal = 79%; Initial SO_2 rate = 0.66 lb/MBtu; SO_2 removal = 70%.

Table 8. Effect of Operating Parameters on IDECS Economics

Plant Size, MWe	$/ton $NO_x + SO_2$ Removed
50	1,775
100	1,358
300	998
Capacity Factor, %	$/ton $NO_x + SO_2$ Removed
10	5,002
30	2,131
65	1,358

V Conclusions

The goal of this project was to demonstrate a new combination of technologies that could meet future environmental requirements and obtain up to 70-percent reduction of NO_x and SO_2 emissions. A secondary, but very important goal, was to accomplish this at a lower capital and operating cost than technologies available at the time this project was initiated. In general, these major goals were achieved. Specific conclusions are the following:

- LNBs plus OFA achieved up to 69-percent NO_x reduction without increasing CO levels or LOI.

- During base-load operation, urea injection achieved an additional 30- to 50-percent NO_x reduction while maintaining an ammonia slip of 10 ppm at the FFDC inlet. This increased the total system NO_x reduction to greater than 80 percent at full load, exceeding the project goal of 70 percent.

- Urea injection resulted in increased N_2O emissions of 29 to 35 percent of the NO_x reduction. If the urea was passed through the ammonia converter before injection, N_2O emissions amounted to only 3 to 8 percent of the NO_x reduction.

- With SNCR in operation, ammonia will absorb on the fly ash in the baghouse, the amount depending upon fly-ash chemistry. Sodium-based DSI increases the ammonia level in the ash and may cause odor or ash-disposal problems.

- Design of the urea injection lances is important for proper SNCR performance, especially with large units.

- Both sodium-sesquicarbonate and sodium-bicarbonate DSI achieved 70-percent SO_2 removal, but hydrated-lime injection achieved only low SO_2 removals. Thus, hydrated-lime injection is unlikely to be implemented on other units.

- Both sodium sesquicarbonate and sodium bicarbonate cause the oxidation of NO to NO_2, probably by a catalytic reaction. This results in a slight decrease (less than 10 percent) in overall NO_x emissions, but higher than baseline NO_2 stack emissions. Because NO_2 is highly colored, this may lead to a visible stack plume at high sodium-injection rates. When compared at the same SO_2-removal rate, sodium sesquicarbonate creates only half as much NO_2 as sodium bicarbonate.

- The integration of SNCR with sodium-based DSI decreased NO_2 emissions by approximately 50 percent, compared with using sodium-based DSI without SNCR. The combination also decreased ammonia emissions that occur with SNCR alone, but the level was difficult to quantify.

This project can be declared a technical success, because the technical goals were generally met and the facility is continuing to use the technology to lower emissions levels. However, the potential market for the integrated system appears to be somewhat limited, in large part because of the more stringent air pollution regulations now in effect compared to those in effect when this project was instituted, and the trend towards installing more expensive processes that achieve high removal levels. Also, the sodium and ammonia contents of the ash may limit ash sales and present disposal problems in some cases.

Abbreviations

ARILs	Advanced Retractable Injection Lances
B&W	Babcock & Wilcox
$CaCO_3$	calcium carbonate
$Ca(OH)_2$	slaked or hydrated lime, or calcium hydroxide
CCT	Clean Coal Technology
CEM	continuous emissions monitor
CO	carbon monoxide
CO_2	carbon dioxide
DOE	U.S. Department of Energy
DPSC	Diamond Power Specialty Company
DRB-XCL®	Dual-Register Burner–Axially-Controlled Low-NO_x
DSI	dry sorbent injection
EPRI	Electric Power Research Institute
FERCo	Fossil Energy Research Corporation
FFDC	fabric-filter dust collector
FGD	flue-gas desulfurization
FGH	flue-gas humidification
HNCO	cyanic acid
IDECS	Integrated Dry NO_x/SO_2 Emissions Control System
LNB	low-NO_x burner
LOI	loss-on-ignition
Na_2CO_3	soda ash
$Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O$	sodium sesquicarbonate
$NaHCO_3$	sodium bicarbonate
$(NH_2)_2CO$	urea
NH_3	ammonia
NO	nitric oxide
NO_x	nitrogen oxides
NO_2	nitrogen dioxide
N_2O	nitrous oxide
NSPS	New Source Performance Standards
NSR	normalized stoichiometric ratio
OFA	overfire air
PPA	post-project assessment
PSCC	Public Service Company of Colorado
SCR	selective catalytic reduction
SNCR	selective noncatalytic reduction
SO_2	sulfur dioxide
SOW	statement of work
T_{AS}	approach to saturation temperature
WRI	Western Research Institute

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