INTEGRATED DRY NOx/SO2 EMISSIONS CONTROL SYSTEM

Final Report, Volume 2: Project Performance and Economics

Clean Coal Technology Projects
Federal Energy Technology Center (FETC)

DOE Contract Number DE-FC22-91PC90550

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Draft: December 1994
Final: September 1999

Patents cleared by Chicago on 1-6-00

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ABSTRACT

The United States Department of Energy (DOE) and Public Service Company of Colorado (PSCC) signed a cooperative agreement for the Integrated Dry NO_x/SO_2 Emissions Control System in March 1991. This project integrates various combinations of five existing and emerging technologies onto a 100 MWe, down-fired, load-following unit that burns pulverized coal. The project goals are to achieve up to 70% reductions in both oxides of nitrogen (NO_x) and sulfur dioxide (SO_2) emissions.

Various combinations of low-NO_x burners (LNB), overfire air (OFA) ports, selective noncatalytic reduction (SNCR), dry sorbent injection (DSI) using both calcium- and sodium-based reagents, and flue-gas humidification are expected to integrate synergistically and control both NO_x and SO_2 emissions better than if each technology were used alone. For instance, ammonia emissions from the SNCR system are expected to reduce NO_2 emissions and allow the DSI system (sodium-based reagents) to achieve higher removals of SO_2.

Unlike tangentially- or wall-fired units, down-fired units require substantial modification to their pressure parts to retrofit LNB's and OFA ports, substantially increasing the cost of the retrofit. Conversely, the retrofitting of SNCR, DSI, or humidification systems does not require any major boiler modifications and are easily retrofitted to all boiler types. Existing furnace geometry and flue-gas temperatures, however, can limit their placement and effectiveness. In particular, SNCR requires the injection of the SNCR chemicals into the furnace where the temperature is within a very narrow temperature range.

Most of the construction was completed in August 1992. Testing was completed from January 1992 through December 1996. The project cost was slightly under the $27.4 million project budget.

ACKNOWLEDGEMENTS

The authors would like to thank the many Arapahoe Station maintenance and operating personnel for the exceptional cooperation they provided during this project. Special thanks are also extended to Mr. Jerry Hebb and Mr. David Hunter at the DOE Pittsburgh Energy Technology Center, and Mr. Tom Arrigoni and Mr. Tim McIlvried posthumously of DOE whose advice and contributions were greatly appreciated. The advice and technical assistance provided by Mr. Jeff Stallings and Ms. Barbara Toole-O'Neil at the Electric Power Research Institute (EPRI) has also been of great assistance throughout the project. Lastly, the authors would like to extend our appreciation to the many engineering and construction personnel of PSCC and other contractors who have made the Integrated Dry NO_x/SO_2 Emissions Control System project a success.

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ABBREVIATIONS

B&W	The Babcock & Wilcox Company, a McDermott company
BZHRR	Burner zone heat release rate (Btu/h-ft^2)
CCT-III	Third Clean Coal Technology demonstration program
CEM	Continuous emission monitor
DCS	Distributive control system
DOE	United States Department of Energy
DRB-XCL™	Dual-range burner, axially-controlled low-NO$_x$
DSI	Dry sorbent injection (also called duct sorbent injection)
EPRI	Electric Power Research Institute
ESP	Electrostatic precipitator
FC/VM	Ratio of fixed carbon to volatile matter
FERCo	Fossil Energy Research Corporation
FGD	Flue-gas desulfurization
FGR	Flue-gas recirculation
HVT	High-velocity thermocouple, suction pyrometry
id	Inside diameter
ID fan	Induced-draft fan
LCP	Local control panel
LNB	Low NO$_x$ Burner
MCC	Motor control center
MW	Molecular weight
NSPS	New Source Performance Standards
NSR	Normalized stoichiometric ratio
OFA	Overfire air
PLC	Programmable logic controller
PSCC	Public Service Company of Colorado
SNCR	Selective noncatalytic reduction (also called urea injection)
U.S.	United States
UBC	Unburned carbon
UCC	United Conveyor Corporation

UNITS

acfm	actual cubic feet per minute
Btu	British thermal unit. Approximately the heat required to raise 1 lb of water 1 F.
Btu/lb	British thermal units per pound of fuel
Btu/h	British thermal unit per hour
Btu/ft^3	British thermal units per cubic foot of gas
cP	centiPoise
ft	feet
ft^2	square feet
ft^3/h	cubic feet per hour
ft^3/min	cubic feet per minute
gal	gallons
gal/min	gallons per minute
grains/dSCF	grains per dry standard cubic foot
Hz	Hertz (cycles per second)
icfm	inlet cubic feet per minute
id	inside diameter
inH$_2$Og	inches water (gauge)
inHg	inches of mercury (pressure)
kW	kilowatt (1,000 watts)
kW-h	kilowatt-hour
lb/MMBtu	pounds per million British thermal unit
lb/h	pounds per hour
lbm/h	pound-mass per hour
MCFH	1,000 cubic feet per hour
MMBtu/h	1,000,000 British thermal units per hour
MMBtu	1,000,000 British thermal heat units
mole/h	moles per hour

UNITS (Continued)

MWe	megawatts (electric)
#	number
ppm	parts per million
ppmv	parts per million by volume
ppmw	parts per million by weight
psig	pounds per square inch (gauge)
scfm	standard cubic feet per minute (at 1 atmosphere and 60 F)
t/h	tons per hour
V	Volts
VAC	Volts, alternating current
vol%	percent content by volume
wt%	percent content by weight
°F	degrees Fahrenheit
µm	micrometer (10^{-6} meters)

GLOSSARY

agglomeration	Groups of fine dust particles clinging together to form a larger particle.
air heater	A heat transfer device used to heat air. At Arapahoe Unit 4, the hot flue-gas preheats the combustion air before it enters the boiler.
air staging	Removal of a portion of combustion air from the primary combustion zone and introducing it in another combustion zone. The combustion zones may be within a burner or across the furnace.
air-to-cloth ratio	Ratio of the flue-gas flowrate (acfm) to the area of the bag filters (ft^2). This ratio indicates the relative size of an FFDC.
air-to-liquid ratio	Ratio of the injected urea solution (liquid) and atomizing air.
amidogen	NH_2
amine radical	Large group of chemicals derived from ammoina in which one or more hydrogen atoms has been replaced with an organic radical.
ammonia slip	The excess ammonia emitted by a unit because of the injection of urea or ammonia into the furnace for SNCR.
Ammonia	NH_3
aqueous ammonia	NH_4OH
ash	The incombustible solid matter in a fuel.
Atomizer	Nozzle that reduces a liquid to a very fine spray.
Baghouse	See **FFDC**.
baseload station	A generating station that is normally operated to produce load for a system's base load. Therefore, the station runs at virtually a constant load.
bulk furnace residence time	Computed by dividing the volume of the furnace (the space between the burners and the leading convective surface) by the total flowrate of the flue gas. Represents the amount of time the fuel has to burn completely.
C	Carbon.
Ca	Calcium.
$Ca(OH)_2$	Calcium hydroxide (hydrated lime).

GLOSSARY (Continued)

$CaCO_3$	Calcium carbonate (limestone).
CaO	Calcium oxide (lime).
$CaSO_3$	Calcium sulfite.
$CaSO_4$	Calcium sulfate.
Char	The product of coal devolatization. It consists of unburned carbon, a small amount of hydrocarbons (high molecular weight), and ash.
CO	Carbon monoxide.
CO_2	Carbon dioxide.
Coal reactivity	A qualitative measure of a coal's propensity to burn rapidly. Measured by the coal's content of volatile matter and FC/VM.
Combustion air	The air used to burn the coal. Consists of the primary, secondary, and overfire air.
Cyanic (or isocyanic) acid	HNCO
direct-fired unit	Unit that pulverizes coal in proportion to load and conveys it directly to the burners.
Down-fired unit (or boiler)	A furnace in which the burners are arranged so that the air and fuel flow down through the roof into the boiler. Also called vertical-fired, roof-fired, or top-fired.
Downcomer	A tube in the water wall system of a boiler in which the fluid flows downward.
dry sorbent injection (DSI)	Injection of dry calcium- or sodium-based reagents into the economizer or furnace duct to remove SO_2 from the flue gas.
Economizer	Heat recovery device used to transfer heat from the products of combustion (the flue gas) to the feedwater.
Electrostatic precipitator (ESP)	Device that collects dust, mist, or fumes from a gas stream by placing an electrical charge on the particle and collecting it on an electrode.
Endothermic reaction	Reaction that absorbs heat.
Excess O_2	Used to determine the amount of combustion air above that required for stoichiometric combustion of the fuel.

GLOSSARY (Continued)

exhauster	Fan connected to the outlet of a pulverizer that pulls primary air through the pulverizer.
Exothermic reaction	Reaction that releases heat.
FC/VM ratio	Ratio of fixed carbon to volatile matter in coal. Measure of a coal's reactivity.
FFDC	Fabric filter dust collector. Used to remove ash particles from a unit's flue gas.
Fixed carbon	Carbonaceous residue less the ash remaining in a test container after the volatile matter has been driven off in a proximate analysis.
Flame scanner (detector)	Device that indicates if a flame is present. Arapahoe Unit 4 uses an ultraviolet flame scanner to monitor the firing of natural gas and an infrared flame scanner to monitor the burning of coal.
flue gas	Gaseous products of combustion in the flue to the stack.
Flyash	Fine particles of ash carried by the products of combustion out of the boiler.
free moisture	Water contained in a solid that is not chemically bound to the solid.
fuel staging	The introduction of fuel into the combustion air in steps.
fuel NO_x	NO_x produced by combination of the nitrogen released from the fuel and oxygen.
H	Hydrogen.
H_2O	Water.
H_2S	Hydrogen sulfide.
HNCO	Cyanic or isocyanic acid.
Ignitor	Small gas or oil burner used to ignite a larger fuel stream.
Intertube burners	Burners located between the tubes of a boiler convection bank.
Lance	Pipe that supports injectors in boiler duct.

GLOSSARY (Continued)

lignite coal	*Consolidated coal of low classification according to rank:* less than 8,300 Btu (moist).
Load-following station	A generating station operated at various points to follow an automatic demand signal.
loss on ignition (LOI)	Test used to determine an approximation of the amount of unburned carbon in the flyash. Generally provides a slightly higher measurement than direct carbon measurement.
Makeup water	Water added to the boiler to compensate for water lost through exhaust, blowdown, leakage, etc.
momentum ratios	A ratio of mass and velocity that indicates jet penetration.
N	Nitrogen.
N_2	Molecular nitrogen
N_2O	Nitrous oxide (commonly called "laughing gas").
Na	Sodium.
Na_2CO_3	Soda ash.
$Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$	Sodium sesquicarbonate.
Na_2SO_4	Sodium sulfate.
$NaHCO_3$	Sodium bicarbonate.
$NaHCO_3$ Na_2CO_3 $2H_2O$	Sodium sesquicarbonate.
Nahcolite	Mineral name for naturally occurring sodium bicarbonate.
New Source Performance Standards (NSPS)	Standards under a 1971 federal law (Clean Air Act) regulating the air emissions of generating units.
NH_2	Amidogen.
$(NH_2)_2CO$	Urea.
NH_3	Ammonia.
NH_4OH	Aqueous ammonia.
Nitrogen radical	N^-
NO	Nitric oxide.
NO_2	Nitrogen dioxide.

GLOSSARY (*Continued*)

normalized stoichiometric ratio (NSR)	The stoichiometric ratio normalized so that, theoretically, an NSR of 1 removes 100% of a desired species.
NO_x	Oxides of nitrogen (NO and NO_2).
NO_x Ports	B&W's tradename for their OFA ports.
N^-	Nitrogen radical.
O_2	Molecular oxygen.
Overfire air (OFA)	A NO_x control technology that diverts part of the secondary air and injects it through ports downstream of the primary combustion zone. This diversion reduces the oxygen available for NOx formation in the combustion zone.
Oxidation, oxidizes	*The combining of a chemical with oxygen.*
Pitot-tube	Device used to measure the flow of a gas by comparing the static and fluid pressures.
Primary air	In direct-fired units, air passed through the pulverizer to dry and convey the coal to the burners.
Proximate analysis	Analysis of a solid fuel that determines its moisture, volatile matter, fixed carbon, and ash content as a percent of its total weight.
Reducing atmosphere	Atmosphere that tends to remove oxygen from a chemical compound.
Reduction	Removal of oxygen from a chemical compound.
Register	Apparatus used in a burner to regulate the direction and amount of flow and spin for combustion.
Reynolds number	Represents the turbulence of a flowing fluid.
Roof-fired unit	See **down-fired unit (or boiler).**
Scrubber	An apparatus that removes solids from gases by entrainment in water.
Secondary air	Includes all air for combustion except primary air.
Slag	Molten or fused refuse.
Sliding air-damper	Regulates flow of combustion air.

GLOSSARY (Continued)

SO_2	Sulfur dioxide.
Sodium bicarbonate	Dry sodium-based reagent used to remove SO_2 from flue gas. ($NaHCO_3$)
sodium sesquicarbonate	Dry sodium-based reagent used to remove SO_2 from flue gas. ($NaHCO_3$ Na_2CO_3 $2H_2O$)
sootblower	Mechanical device that uses steam or air to clean heat absorbing surfaces.
Stack	Vertical conduit that, due to the difference in densities between the internal and external gases, causes a draft at its base.
Stoichiometric ratio	The ratio of the actual amount of reagent used to that theoretically required to remove all of a targeted species in the flue gas.
Sub-bituminous coal	Coal classification by rank: 8,500 to 13,000 Btu (moist)
swirl	Rate of fuel/air mixing.
Tangential-fired unit	A method of firing in which the burners are arranged so that the center lines of the burners are tangential to an imaginary circle in the furnace.
Thermal NO_x	NO_x formed through high-temperature oxidation of the nitrogen found in the combustion air.
Top-fired unit	See **down-fired unit (or boiler).**
Trona	Mineral name for naturally occurring sodium sesquicarbonate.
Ultimate analysis	Chemical analysis of a solid, liquid, or gaseous fuel. For coal, it determines the content of carbon, hydrogen, sulfur, nitrogen, oxygen, and ash.
Unburned carbon (UBC)	An indicator of combustible losses. The amount of unburned carbon in the flyash.
Urea	$(NH_2)_2CO$
utilization	Ratio of the actual removal rate of a chemical to the NSR. Indicates the theoretical effectiveness of a chemical reaction. For example, a utilization of 40% means that 60% of an injected reagent remained unreacted.

GLOSSARY (Continued)

vertical-firing	See **down-fired unit (or boiler).**
Wall-fired unit	A method of firing in which the burners are arranged on the wall(s) of the furnace to fire horizontally. Also called horizontal firing.
Windbox	A plenum chamber around a burner or a port that maintains air pressure to properly distribute and discharge the air.

EXECUTIVE SUMMARY

This report, *Final Report, Volume 2: Project Performance and Economics,* consolidates the test results, modifications to the design, and estimated costs of the demonstrated processes not reported in *Final Report, Volume 1: Public Design.* *Volume 1* contains an overview of this project, its key design features and data, and its potential commercialization.

Project Background and History

In September 1988, Congress allocated funds for the third Clean Coal Technology program (CCT-III) to demonstrate technologies that can be implemented on existing facilities. In March 1991, the DOE and PSCC signed the cooperative agreement for the Integrated Dry NO_x/SO_2 Emissions Control System as part of CCT-III. PSCC, the DOE, and EPRI sponsored the $27.4 million program.

PSCC conducted the Integrated Dry NO_x/SO_2 Emissions Control System project on Unit 4 at its Arapahoe Steam Electric Generating Station located in Denver, CO. Arapahoe Unit 4 is a down-fired, 100-MWe unit (name plate) designed to burn pulverized coal or natural gas that came on line in 1955. PSCC uses Arapahoe Unit 4 as a load-following unit. The unit's normal capacity factor is 50 to 60%.

The overall goal of this program was to achieve up to 70% reductions in the emissions of NO_x and SO_2 through the integration of existing and emerging technologies while minimizing capital expenditures and limiting waste production to dry solids that can be handled with conventional ash removal equipment.

Project Technologies

The Integrated Dry NO_x/SO_2 Emissions Control System uses various combinations of five major control technologies to control the emissions of both NO_x and SO_2. To control NO_x emissions, the integrated system uses low-NO_x burners (LNB), overfire air (OFA) ports, and selective noncatalytic reduction (SNCR). To control SO_2 emissions, the integrated system uses dry-sorbent injection (DSI) with and without flue-gas humidification.

Low-NOx Burners

The Integrated Dry NO_x/SO_2 Emissions Control System uses Babcock & Wilcox (B&W) Dual Register Burner-Axially Controlled Low-NO_x (DRB-XCL™) burners. These burners use air and fuel staging within the burner to reduce the formation of NO_x. They can also balance the distribution of fuel and air to each burner to optimize combustion efficiency and NO_x reduction. On wall fired-boilers, these burners have achieved NO_x reductions of 35 to 70% from uncontrolled baseline levels.

Retrofitting a down-fired boiler with LNBs requires more outage time, a larger capital investment, and is much more complicated than it is for a tangentially- or wall-fired boiler. Also, down-fired boilers require substantial modifications in order to install the modified burners. These modifications greatly increase the capital cost of installing LNBs on this type of generating unit.

Overfire Air (NOx) Ports

The Integrated Dry NO_x/SO_2 Emissions Control System uses B&W Dual-Zone NO_x Ports. OFA ports use air staging over a larger volume of the furnace than LNBs, diverting part of the combustion air from the primary combustion zone to a zone downstream of the burner. This diversion creates a slightly fuel-rich environment that inhibits the formation of NO_x. B&W Dual-Zone NO_x Ports incorporate a central (inner) zone and an outer zone to provide adequate mixing across the entire furnace.

As with low-NO_x burners, adding OFA ports to a down-fired boiler is more complicated and expensive than it is for a wall- or tangentially-fired unit. Instead of a simple extension of the windbox, installing OFA ports into a down-fired boiler requires new ductwork to carry the OFA to the OFA ports. This additional ductwork must fit the existing unit and significantly increases the capital cost of installing OFA ports. When used with pulverized coal, OFA ports can increase slagging and corrosion in the furnace and decrease combustion efficiency.

Selective Noncatalytic Reduction

SNCR systems inject either urea or ammonia (anhydrous or aqueous) into the flue gas at a point where its temperature is between 1,600 and 2,100 F. In this temperature range and in the presence of oxygen (O_2), the injected chemical releases NH_2 which selectively reacts with NO to form harmless N_2 and H_2O. This reaction reduces NO_x emissions, but increases N_2O and NH_3 emissions.

Small changes in flue-gas temperature at a system's injection points can significantly affect the performance of an SNCR system. When the boiler load is changed, the flue-gas temperature for a particular injection location also changes. Because of this change in temperature, multiple levels of injection are usually required to provide good NO_x removal over a range of boiler load conditions. Coal-fired units retrofitted with SNCR systems have achieved NO_x reductions ranging from below 20% to above 80%.

Dry Sorbent Injection

DSI systems inject dry reagents (calcium- or sodium-based) into the flue gas. Calcium reagents are injected into the flue-gas duct at a point where the flue gas is about 1,000 F (usually before the economizer). Sodium- or calcium-based reagents (for lower SO_2 removal rates than economizer injection) are injected between the air heater and the particulate control device. Through a series of complex reactions, the reagents react with the gaseous SO_2 in the flue gas to form a calcium- or sodium-based solid that can be removed by the particulate control device. SO_2 removals of 70% have been achieved with sodium-based dry sorbents. Calcium-based dry sorbent injection is expected to yield SO_2 removals in the range of 20 to 50%.

DSI systems are simple, use existing ductwork, and have low capital costs. They produce a dry, solid product that can be handled by conventional fly ash systems, but the use of DSI increases the amount of fly ash and adds soluble compounds to it. Because of the increase in fly ash, existing particulate control devices or fly ash handling equipment may be inadequate. Because of the soluble compounds, the fly ash cannot be slurried or sold as a concrete additive.

Flue-Gas Humidification

The flue-gas humidification system injects water into the flue-gas between the air heater and the particulate control device to enhance the effectiveness of the calcium-based reagent injected by the DSI system. Increasing the humidity of the flue-gas does not change the SO_2 removal chemistry of the calcium-based reagent, but it does improve its reactivity. Flue-gas humidification was not expected to increase significantly the effectiveness of sodium-based reagents. Depending on the type of reagent, the rate of injection, furnace geometry, and other operating conditions, the use of flue-gas humidification and DSI with calcium-based reagents has achieved SO_2 removal rates from 20% to 50%.

Operationally, it is important to prevent unevaporated water from reaching the duct walls, obstructions in the duct, or the particulate control device. Increasing the humidification of the flue-gas improves SO_2 removal, but also increases the risks of localized-wetting problems. Therefore, the optimum operating point for the humidification system is a compromise between operation and performance.

Integrated Emissions Control System

The various combinations of emission control technologies were expected to integrate synergistically, for example:

- Combining LNBs and OFA will allow the burners and ports to be adjusted to work together and produce less NO_x.
- With lower levels of NO_x, both the SNCR and DSI systems are expected to achieve higher NO_x and SO_2 removal.
- The SNCR's ammonia emissions are expected to react with NO_2 allowing greater performance from the SNCR and DSI systems.

Major Conclusions From Testing Effort

The Integrated Dry NO_x/SO_2 Emission Control System is an economical method to obtain up to 80% NO_x and 70% SO_2 removal compared to competing technolgies. The technology is most applicable as a retrofit to older and smaller units that fire a low sulfur coal although it can be retrofit to a large range of units of varying boiler types. Major benefits of the system are as follows.

- Up to 80% NO_x removal
- Up to 70% SO_2 removal
- Easily retrofit with short unit outages (other than combustion modifications)
- No additional solid waste streams
- Approximately 70% lower levelized cost per ton of reduced emission than a wet scrubber and selective catalytic reduction (on a unit similar to Arapahoe 4)
- Approximately 50% lower capital cost than a wet scrubber and selective catalytic reduction on a complicated combustion retrofit project (top-fired unit). Greater cost reductions are possible on more common boiler types.

Project's Status

The project was selected in late 1989. Construction was completed in August 1992. Most testing was completed in 1994, but the SNCR system was modified in December 1994. All operation and testing was completed in December 1996. Project completion occurred in July 1997.

Project's Cost

The design, procurement, and installation of the Integrated Dry NO_x/SO_2 Emissions Control System cost $20.9 million. An additional $6.5 million was budgeted for the operating and testing of the system, bringing the total cost of the program to $27.4 million, including overheads. Only a single change to the original budget to account for the additional scope of work for air toxic testing was made during the project. Actual costs to project completion were $26.9 million, approximately 2% under the approved budget. Final costs will not be available until all required auditing is complete.

1 PROJECT OVERVIEW

This section summarizes the purpose of this report, the project, the project site, the objectives, the commercial significance of the project, and the DOE's role in the project.

1.1 Purpose of the Project Performance and Economics Report

The purpose of this report is to consolidate all nonproprietary information on the Integrated Dry NO_x/SO_2 Emissions Control System project not reported in *Final Report, Volume 1: Public Design.* This volume reports test results, modifications to the design, and estimated costs of the demonstration project. *Volume 1* contains an overview of this project, its key design features and data, and its potential commercialization.

1.2 Brief Description of Project

This section briefly describes the history, sponsors, technologies, participants, process flow, test program, and schedule of the project. Sections 2.0 through 6.0 describe the technologies in detail.

The overall goal of this project was to achieve up to 70% reductions in the emissions of NO_x and SO_2 through the integration of existing and emerging technologies while minimizing capital expenditures and limiting waste production to dry solids that can be handled with conventional ash removal equipment.

1.2.1 History

In September 1988, Congress allocated funds for the third Clean Coal Technology demonstration program (CCT-III) to demonstrate technologies that can be implemented on existing facilities. The United States Department of Energy (DOE) then solicited proposals to demonstrate technologies capable of reducing the emissions of oxides of nitrogen (NO_x) and sulfur dioxide (SO_2). In response to the DOE solicitation, the Public Service Company of Colorado (PSCC) proposed the Integrated Dry NO_x/SO_2 Emissions Control System. The DOE selected this system for funding as part of CCT-III. The DOE and PSCC signed the final Cooperative Agreement in March 1991.

1.2.2 Sponsors

PSCC, the DOE, and the Electric Power Research Institute (EPRI) sponsored the Integrated Dry NO_x/SO_2 Emissions Control System program.

1.2.3 Technologies Employed

The Integrated Dry NO_x/SO_2 Emissions Control System uses various combinations of five major control technologies to form integrated systems and to control the emissions of both NO_x and SO_2. To control NO_x emissions, the integrated system uses low-NO_x burners (LNB), overfire air (OFA) ports, and selective noncatalytic reduction (SNCR). To control SO_2 emissions, the integrated system uses dry-sorbent injection (DSI) with and without flue-gas humidification.

1.2.4 Project Participants

PSCC was the project manager for the Integrated Dry NO_x/SO_2 Emissions Control System program, and was responsible for all aspects of project performance. PSCC engineered and installed the DSI system, installed the SNCR system, engineered and installed modifications to the fly ash system, and installed much of the balance of plant systems. PSCC also provided the host site, trained the operators, selected site construction services, startup services and maintenance, and is assisting in the testing program. The following companies also contributed to the project:

- **Babcock and Wilcox (B&W)** was responsible for the engineering, procurement, fabrication, installation, and shop testing of the LNBs, OFA ports, flue-gas humidification equipment, and associated controls. B&W also assisted in the test program, and will help commercialize the technology.
- **NOELL, Inc.** was responsible for the engineering, procurement, and fabrication of the SNCR system.
- **Fossil Energy Research Corporation (FERCo) conducted the test program.**

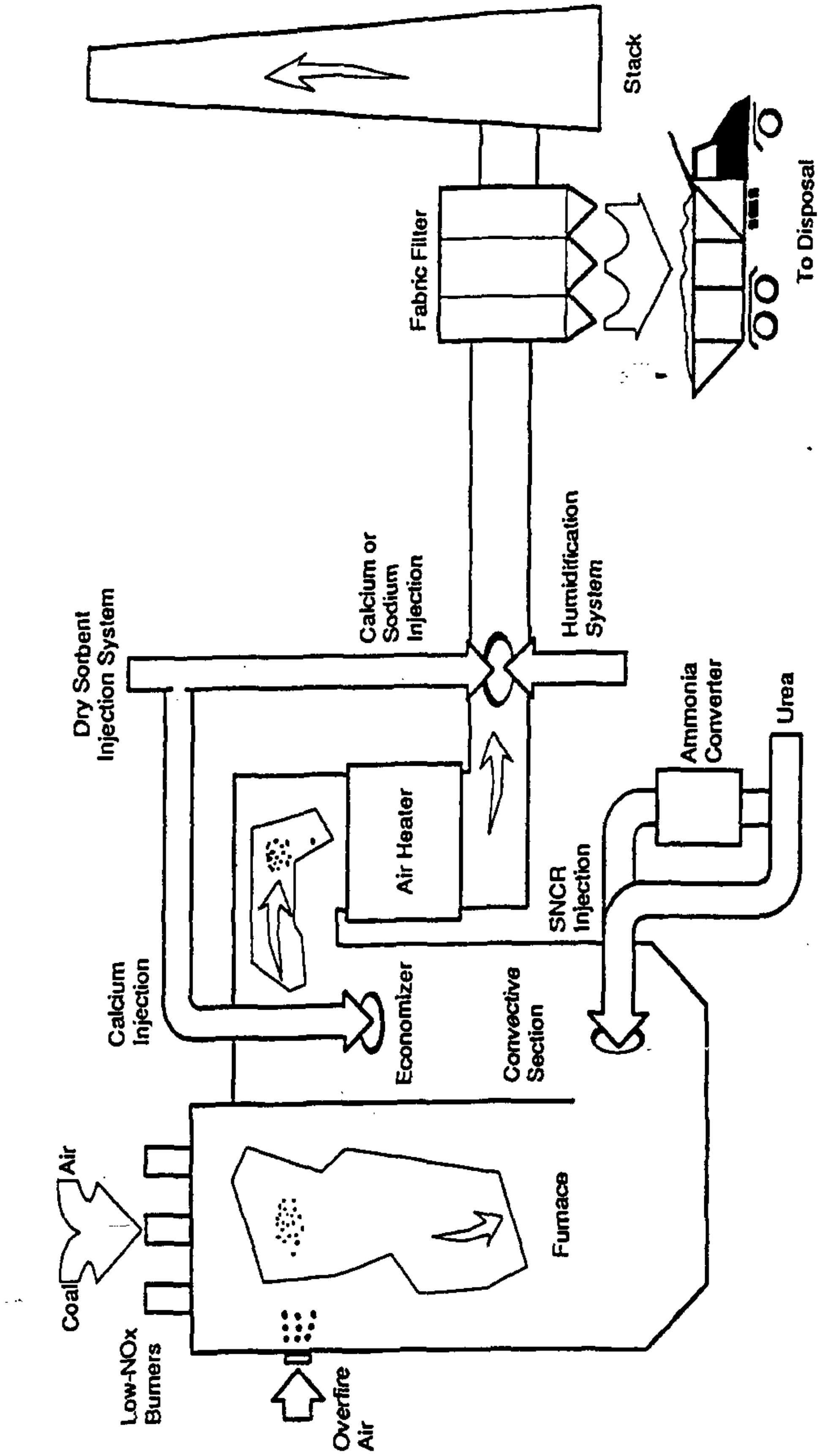


Figure 1-1. Block Flow Diagram of Integrated Dry NO_x/SO_2 Emission Control System

- **Western Research Institute (WRI)** characterized the waste materials and recommended options for their disposal.

- **Colorado School of Mines** conducted research in the areas of bench-scale chemical kinetics for the NO_2 formation reaction with DSI while injecting sodium-based reagents.

- **Stone & Webster Engineering Corporation** assisted PSCC with the engineering efforts.

- **Cyprus Coal and Amax Coal** supplied coal for the project.

- **Coastal Chem, Inc.** provided urea for the SNCR system.

1.2.5 Project Block Flow Diagram

Figure 1-1 shows a simplified block flow diagram of the integrated system.

1.2.6 Summary of Planned Test Program

Because of the number of technologies this project integrated, the test program was divided into the following test activities; each test activity was documented in a separate report:

- **Baseline tests of the original combustion system:** Provided the basis for comparing the performance of the individual technologies and that of the integrated system.

- **Baseline combustion system/SNCR:** Tested the performance of SNCR (urea and ammonia injection) with the original combustion system.

- **LNBs/OFA:** Identified the optimum operating conditions and settings for the LNBs and the OFA ports. Assessed the performance of the LNBs and the OFA ports.

- **LNBs/OFA/SNCR:** Tested the NO_x reduction potential of the low-NO_x combustion system (LNBs and OFA) and SNCR.

- **LNBs/OFA/DSI (calcium-based reagents):** Tested the injection of calcium-based reagents into the economizer and into the duct with flue-gas humidification during the operation of the low-NO_x combustion system.

- **LNBs/OFA/DSI (sodium-based reagents):** Tested the SO_2 removal performance of sodium-based reagents in the DSI system with the low-NO_x combustion system.

- **Integrated systems:** Tested the NO_x and SO_2 reduction potential of the integrated system using LNBs, OFA SNCR, and DSI (calcium- or sodium-based reagents).

In addition to investigating the emissions of NO_x and SO_2, the test program investigated the emissions of air toxics. Baseline levels for the emissions of air toxics were obtained during the testing of the low-NO_x combustion system. Three additional tests were also performed during each of the urea, calcium, and sodium injection tests to determine the potential of these pollution control technologies for removing air toxics.

1.2.7 Overall Schedule for Project

Table 1-1 summarizes the schedule for the project

Activity/Milestone	Start	End
Project selection	12/89	---
Cooperative Agreement signed	3/11/92	---
Construction	7/91	8/92
Baseline Tests	11/11/91	12/15/91
SNCR tests (original combustion system)	2/4/92	3/6/92
Startup of Low-NO_x burners	---	5/30/92
Low-NO_x burners and OFA tests	8/6/92	10/29/92
SNCR tests (low-NO_x combustion system)	1/11/92	4/9/93
DSI tests: calcium-based reagents	4/30/93	10/20/93
DSI tests: sodium-based reagents	8/4/93	5/27/94
Air toxics tests: Baseline	11/17/92	11/19/92
Air toxics tests: SNCR	3/8/93	3/15/93
Air toxics tests: DSI with sodium based reagents	10/14/93	10/15/93
Air toxics tests: DSI with calcium-based reagents	10/19/93	10/20/93
Integrated system Tests	2/7/94	12/96
Supplementary SNCR tests	4/1/95	11/96
Project completion	---	6/30/97

Table 1-1. Project Schedule

1.3 Site Description

This section describes the generating station and unit where the Integrated Dry NO_x/SO_2 Emissions Control System was conducted and the coals normally fired there. The data presented in this section was used as the basis for the design and retrofit of the Integrated Dry NO_x/SO_2 Emissions Control System.

PSCC conducted the demonstration program at its Arapahoe Steam Electric Generating Station located in Denver, CO. The generating station includes four coal-fired steam electric generating units with a total generating capacity of 232 MWe (nameplate). The demonstration system was installed on Unit 4. Elevation of the site is 5,300 feet above sea level. Table 1-2 lists the ambient conditions at Arapahoe Station.

Ambient Conditions	
Elevation	5,300 ft
Atmospheric pressure	12.2 psi
Air temperature range	-20 to 110°F
Average temperature	60°F

Table 1-2. Ambient Conditions

1.3.1 Arapahoe Unit 4

Arapahoe Unit 4 is a down-fired, 100-MWe unit (name plate) designed to burn pulverized coal or natural gas. It came on line in 1955 and is the largest generating unit at Arapahoe Station. PSCC uses Arapahoe Unit 4 as a load-following unit; therefore, it can experience large and rapid load swings. The unit generally operates at high capacity-factors. The unit's normal capacity factor is 50 to 60%. Table 1-3 summarizes the design and operating information for Arapahoe Unit 4.

Arapahoe Unit 4		
Capacity	Maximum	112.5 MWe
	Name plate	100 MWe
	Number of burners	12
Heat Transfer	Heat release rate	14,700 Btu/ft^3 of furnace volume
	Area of heat surface	15,744 ft^3
Steam	Total flowrate	1,004,400 lb/h
	Temperature	1,005°F
	Pressure	1,530 psig
Flue-gas	Design duct gas velocity	3,6600 ft/min
	Air heater exit/FFDC inlet temperature	290°F
	Flowrate	1,236,000 lb/h
	Base NO_x emissions (full load)	840 ppm at 3% O_2 (1.15 lb/MMBtu)
	Base SO_2 emissions (full load)	350 ppm 15 3% O_2 (0.66 lb/MMBtu)

Table 1-3. Design and Operating Information on Arapahoe Unit 4

1.3.1.1 Pulverizers

Arapahoe Unit 4 has four Riley Stoker Model Atrita Series 550 duplex pulverizers. These are the original mills supplied with the boiler unit. Although normal procedure is to operate all four mills, Arapahoe Unit 4 can maintain design load with only three mills in operation.

Previous performance testing has shown that 99% of the coal produced by the pulverizers can pass through a U.S. Standard 50 mesh screen and that 70% of the coal produced by the pulverizers can pass through a U.S. Standard 200 mesh screen. Each pulverizer was designed for a primary airflow of 46,000 lb/h. The original Riley pulverizers were not modified, but new variable-speed feeder drives were added to provide a more consistent feed of coal to the pulverizers as part of this project. Table 1-4 summarizes the information on the pulverizers.

Pulverizers	
Vendor/Type	Riley Stoker Atrita Series 550 Duplex Pulverizers
Quantity	4
Flowrate of primary air per pulverizer	46,000 lb/hr
Coal fineness	99%-U.S. standard 50 mesh 70%-U.S. standard 200 mesh
Date installed	1955 (original to plant)

Table 1-4. Pulverizer Design and Operating Information

1.3.1.2 Particulate Control Device

The existing Ecolaire Fabric Filter Dust Collector (FFDC) was installed in 1980. It filters the flue-gas from both Arapahoe Units 3 and 4. The FFDC removes greater than 99% of the fly ash particulates and will remain essentially unaffected by the project. Table 1-5 summarizes the information on the particulate control device.

Particulate Control Device	
Vendor/type	Ecolaire FFDC
Fly ash particulate removal rate	>99%
Number of compartments	12
Bags per compartment	252
Design air-to-cloth ratio	2.0
Outlet dust loading	0.007 grains/DSCF
Date installed	1980

Table 1-5 Design and Operating Information for Particulate Control Device

1.3.2 Coal Fired at Arapahoe

Currently, Arapahoe Unit 4 mainly burns two low-sulfur (0.4% sulfur) bituminous coals mined in Colorado: Cyprus Yampa Valley and Empire Energy Coals. Although Arapahoe Unit 4 can use natural gas to run at full load, natural gas is used only occasionally to provide load when pulverizers or other equipment are out of service. Table 1-6 lists the proximate analysis and Table 1-7 lists the ultimate analysis for Cyprus Yampa coal. Table 1-8 lists the proximate analysis and Table 1-9 lists the ultimate analysis for Empire Energy coal.

1.4 Objectives of Project

The technologies of the Integrated Dry NO_x/SO_2 Emissions Control System were expected to integrate synergistically and achieve higher emissions reductions than they could operating separately. The emissions reduction goal of the project was to demonstrate up to 70% reductions in both NO_x and SO_2. The Integrated Dry NO_x/SO_2 Emissions Control System demonstrated the **first**:

- Integration of LNBs, OFA ports, SNCR, DSI, and flue-gas humidification into a single emission control system.
- Application of LNBs to a down-fired boiler firing pulverized-coal.
- Application of OFA ports to a pulverized-coal, down-fired boiler.
- Use of an SNCR system on a coal-fired utility boiler in the U.S.
- Combined use of DSI and SNCR

1.5 Significance of Project

The extensive testing program for the integrated system addresses the performance of each individual system (except LNBs and OFA ports which always operate together) as well as various combinations of the systems. This program establishes an alternative technology to the use of wet or dry flue-gas desulfurization (FGD) for SO_2 emissions control and SCR processes for NO_x emissions control.

Property	As Received
Moisture	10.6%
Ash	9.6%
Volatile matter	34.1%
Fixed carbon	45.75
Total	100%
FC/VM	1.33
Heating Value	11,050 Btu/lb

Table 1-6. Proximate Analysis of Cyprus Yampa Coal

Property	As Received
Moisture	10.6%
Carbon	62.8%
Hydrogen	4.5%
Nitrogen	1.6%
Chlorine	negligible
Sulfur	0.4%
Ash	9.6%
Oxygen (difference)	10.5%
Total	100%

Table 1-7. Ultimate Analysis of Cyprus Yampa Coal

Property	As Received
Moisture	13.2%
Ash	8.0%
Volatile matter	33.8%
Fixed carbon	45.0%
Total	100%
FC/VM	1.33
Heating Value	10,600 Btu/lb

Table 1-8. Proximate Analysis of Empire Energy Coal

Property	As Received
Moisture	13.2%
Carbon	61.5%
Hydrogen	4.5%
Nitrogen	1.3%
Chlorine	negligible
Sulfur (average)	0.4%
Ash (average)	8.0%
Oxygen (difference)	11.1%
Total	100%

Table 1-9 Ultimate Analysis of EmpireEnergy Coal

The Integrated Dry NO_x/SO_2 Emissions Control System program demonstrates at utility scale new integrated combustion and flue-gas cleanup technologies for the removal of potential acid-rain and secondary particulate causing emissions. This project is directed particularly at down-fired units, but its results are also applicable to other types of units.

Currently, down-fired units represent a market without any demonstrated low-cost NO_x and SO_2 removal systems. Consequently, the commercialization of the technology required a comprehensive data base to demonstrate the emission control, performance enhancements, reliability, and cost effectiveness of the technology.

1.5.1 Commercialization

This demonstration project established that the combinations of technologies used by the Integrated Dry NO_x/SO_2 Emissions Control System are effective, reliable, and economic approaches to the control of NO_x and SO_2. The technology has the potential to penetrate not only the pre-New Source Performance Standards (NSPS) down-fired and wall-fired wet-bottom utility-boiler market, but the pre-NSPS dry-bottom wall-fired utility-boiler and the industrial boiler markets as well.

The Integrated Dry NO_x/SO_2 Emissions Control System has many advantages for commercialization. Either the entire integrated emissions control system or its parts:

- Can be retrofitted to most utility and industrial coal-fire units with modest capital investment and downtime. It is mainly applicable to older, small- to mid-size units.
- Is a lower capital-cost alternative to conventional wet flue-gas desulfurization processes. It also requires substantially lower space allowing for easy retrofitting.
- Can be applied to a wide range of coals.

The Integrated Dry NO_x/SO_2 Emissions Control System has many features expected to increase the project's potential for commercialization. The integrated emission control system:

- Uses proven, commercially available equipment.

- Simultaneously removes up to 70% of NO_x and SO_2.
- Has low to moderate capital and operating costs.
- Can use sodium- or calcium-based reagents depending on cost and disposal requirements.
- Uses existing fly ash removal systems. Forms dry, free flowing, non-toxic reaction products that are removed by downstream particulate-removal systems and disposed of with the rest of the fly ash.
- Requires minimum space to aid retrofitting.

Transferring the information gained by this program directly to industry will help the commercialization of the Integrated Dry NO_x/SO_2 Emissions Control System. Therefore, applicable project information (non-proprietary) is being made available to the utility industry and to other potential users of the technology.

1.5.2 Level of Technical and Commercial Risk Reduction

Although there was already some experience with the individual technologies of the Integrated Dry NO_x/SO_2 Emissions Control System, the effectiveness of the entire system had not been demonstrated. The utility industry is the main market for the demonstrated technology. The system's potential customers must be able to demonstrate to their regulating agencies that their planned emissions control equipment is proven effective and economical. Therefore, demonstrating that the Integrated Dry NO_x/SO_2 Emissions Control system is an effective and economical method for controlling NO_x and SO_2 emissions on a full-scale generating unit enhanced the commercialization of the demonstrated technology.

1.5.3 Known Concerns to be Met by Project

It was anticipated that the integrated control system would reduce both NO_x and SO_2 emissions by up to 70% at costs lower than other technologies now available, but there were technical concerns with some of the technologies. For example, an undesirable side effect of sodium-based DSI at high levels of SO_2 removal rates is the oxidation of nitric oxide (NO) to nitrogen dioxide (NO_2) that results in the colorization of the exhaust plume. Pilot-scale testing, sponsored by EPRI, had shown that ammonia (NH_3) can suppress the net conversion of NO to NO_2.

Therefore, when SNCR and DSI (using sodium-based reagents) were integrated, the byproduct NH_3 from the SNCR system was expected to suppress the net conversion of NO to NO_2 in the DSI system. It was also expected that this reaction would reduce the excess NH_3 emissions (ammonia slip) produced by SNCR. The project investigated the difficulties of installing LNBs, OFA ports, and SNCR on a down-fired boiler burning pulverized coal.

1.6 DOE's Role in Project

The DOE oversaw the management of the Integrated Dry NO_x/SO_2 Emissions Control program and provided 50% of its financing. In addition, the DOE:

- Was responsible for monitoring all aspects of the project and for granting or denying approvals based on the Cooperative agreement.
- Provided technical advice.
- Reviewed technical reports.
- Published the technical data and test conclusions for use by the public.

1.7 Management Plan

Figure 1-2 shows the organization chart of the demonstration program for the Integrated Dry NO_x/SO_2 Emissions System. As overall manager, PSCC was responsible for all aspects of project performance including budget, scheduling, and contracting for the required scope of work. PSCC assigned a Project Engineer to control the project and manage the detailed technical work. Although the project used various PSCC engineering and support personnel to help complete the work, PSCC contracted much of the work to companies with experience and knowledge in the various technologies. This team of an experienced project manager and core of experienced professionals has brought the project through its design, construction, and testing phases on time and budget.

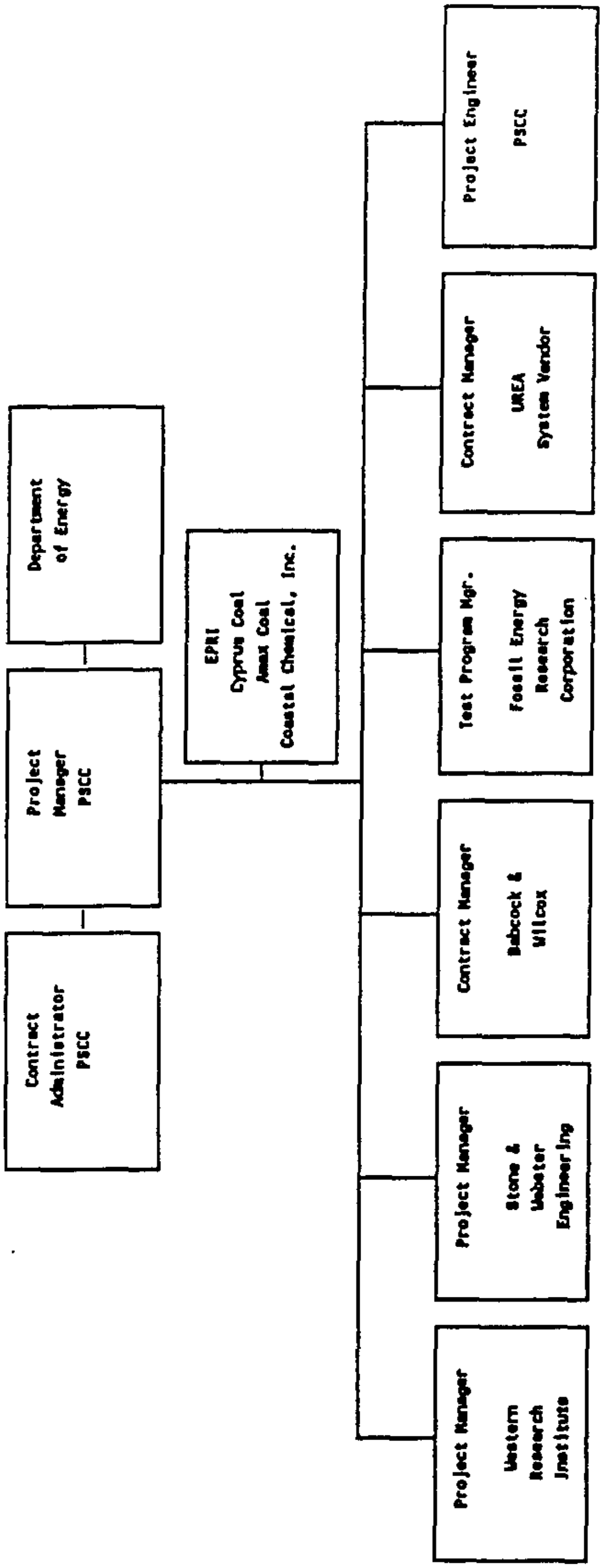


Figure 1-2. Program Organization Chart

2 LOW-NO$_x$ COMBUSTION SYSTEM

This section describes the technology LNBs and OFA ports use to reduce NO$_x$ emissions and the low-NO$_x$ combustion system at Arapahoe Unit 4. It also describes the objectives, methodology, and results from the test program for the low-NO$_x$ combustion system.

2.1 Technology Description

Characteristically, pulverized-coal-fired generating plants with intertube down-fired burners emit high levels of NO$_x$. Based on operating experience with wall-fired boilers, retrofitting DRB-XCL™ burners to Arapahoe Unit 4's down-fired boiler was expected to reduce NO$_x$ emissions by up to 50%; combining the LNBs with OFA ports was expected to reduce NO$_x$ emissions by up to 70%. This section describes the chemistry of NO$_x$ formation, the DRB-XCL™ burner, the Dual-Zone NO$_x$ Port, and the retrofit of the low-NO$_x$ combustion system to Arapahoe Unit 4. For more information on the design of the low-NO$_x$ combustion system, refer to *Final Report, Volume 1: Public Design.*

2.1.1 NO$_x$ Formation Chemistry

The oxidation of nitrogen (N) from two sources forms most of the NO$_x$ in flue-gas: (1) atmospheric nitrogen and (2) fuel-bound nitrogen. The oxidation of nitrogen in the atmosphere (combustion air) with oxygen forms "thermal-NO$_x$." The oxidation of nitrogen bound in the fuel with oxygen forms "fuel-NO$_x$." While burning pulverized coal, fuel-NO$_x$ is the primary source of NO$_x$ emissions, although thermal-NO$_x$ is also a significant contributor. While burning natural gas, thermal-NO$_x$ is the primary source of NO$_x$ emissions.

Coal burns in two stages: (1) devolatization and (2) char burnout. Typically, about 0.5 to 2.0% of a coal's content is nitrogen bound in its organic matter. When burned, coal releases this nitrogen as a reactive species (typically hydrogen cyanide, HCN, and ammonia, NH_3) that can combine with oxygen in the air to form fuel-NO$_x$. It is estimated that 60 to 90% of fuel-NO$_x$ is formed during devolatilization.

The availability of oxygen during devolatilization promotes the conversion of the released nitrogen species to NO_x. Therefore, the most effective means of inhibiting the formation of fuel-NO_x is to limit the availability of oxygen during devolatilization. Instead of the released nitrogen species combining with oxygen, they combine with each other to form N_2. To maintain a high level of combustion efficiency, the remaining air is added later in the process (during char burnout).

Studies have shown that decreasing the temperature and the O_2 concentration at the flame-front inhibits the formation of thermal-NO_x. Diverting combustion air away from the flame-front lowers the O_2 concentration (creates an oxygen-lean, fuel-rich environment), lowers the temperature at the flame-front, and inhibits the formation of thermal-NO_x.

In contrast, the production of fuel-NO_x is relatively unaffected by temperature. Studies indicate that the primary factor in the production of fuel-NO_x is the availability of oxygen to react with the fuel-bound nitrogen compounds when they are converted to gases. Gaseous nitrogen compounds produced from coal are fairly unstable and form N_2 in a fuel-rich environment.

2.1.2 The B&W DRB-XCL™ Burner

The B&W DRB-XCL™ burner uses air and fuel staging to reduce the formation of NO_x. Further, it is designed so that the amount of combustion air can be measured and regulated to balance the distribution of fuel and air to each burner. This balance is important for optimizing combustion efficiency and NO_x reduction.

Fuel staging is the introduction of fuel in stages. In conjunction with air staging, the design of the DRB-XCL™ burner accelerates the combustion of the fuel immediately after it leaves the burner, but in an oxygen-lean (fuel-rich) zone. The devolatization of the coal in a fuel-rich environment creates hydrocarbon radicals that can reduce some of the NO to N_2. The DRB-XCL™ burner is shown in Figure 2-1.

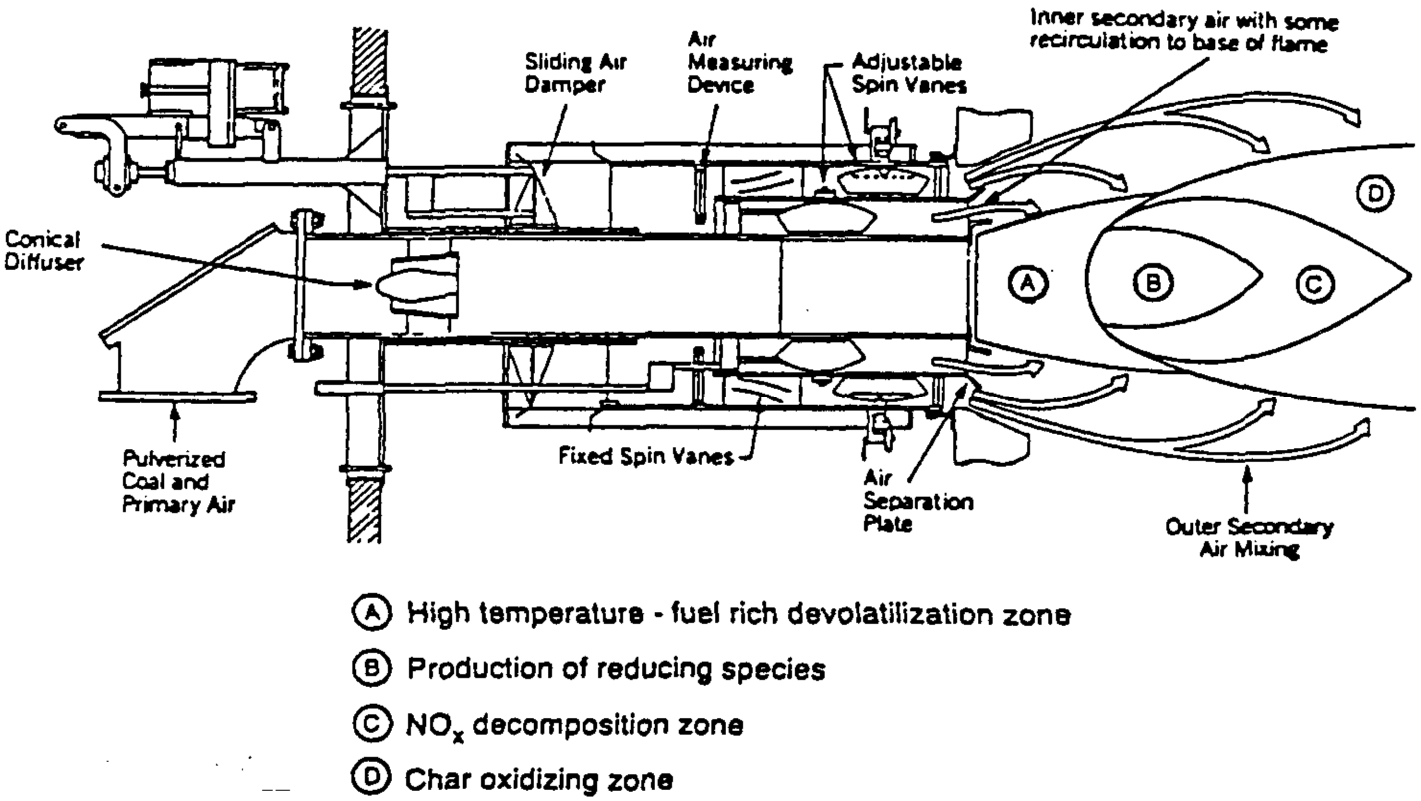


Figure 2-1. DRB-XCL™ Burner

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 multi-stage 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. The adjustable outer vanes control the mixing of the remaining secondary air into the flame.

2.1.3 The B&W Dual-Zone NO_x Port

A typical pulverized coal system operates at 15 to 20% excess air (above stoichiometric). Reducing the flow of air to the burners (even to below stoichiometric) decreases the formation of NO_x. The greater the reduction in airflow to the burners, the greater the reduction in NO_x emissions. As the airflow to the burners is decreased, however, the system requires larger amounts and better mixing of OFA to complete combustion. At some point, depending on the system, the OFA system cannot complete the combustion of the coal so that further reducing the air to the burners increases unburned carbon loss, slagging, and corrosion.

The design of conventional single-jet OFA ports is a compromise between adequately mixing the fuel and air near the furnace wall in which the OFA port is mounted and adequately mixing it across the entire furnace. The use of two jets, as in the B&W Dual-Zone NO_x Port, can minimize or eliminate the need for this compromise.

Figure 2-2 shows a drawing of a NO_x port. The central zone is designed to produce a jet of air with sufficient axial momentum to reach across an entire furnace. The outer 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 than with a single-jet OFA port and reduces the emissions of CO and promotes the burnout of solid carbon.

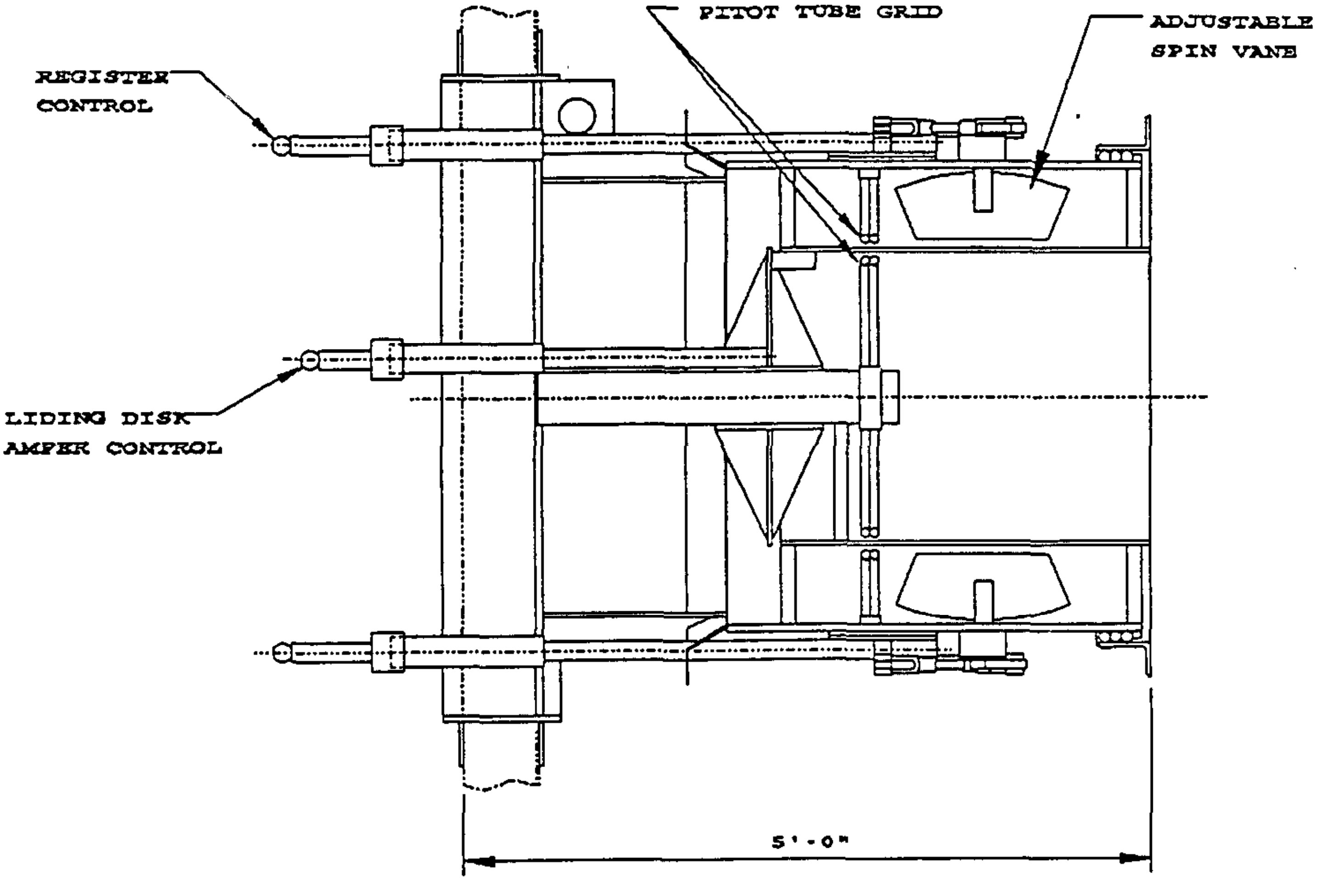


Figure 2-2. B&W DRB-XCL™ Dual-Zone NO_x Port (Source: B&W)

The central zone has a manual air-control disk for flow control. The manually adjustable sliding damper controls the airflow to the inner zone to provide sufficient mixing across the entire furnace. The outer zone incorporates manually adjustable spin-vanes for swirl control. These adjustable spin vanes improve mixing near the furnace walls. In addition, each NO_x port has an airflow measurement device in each air zone for balancing the distribution of the OFA.

2.1.4 Design Concerns (Difficulty of Retrofit)

Retrofitting a down-fired boiler for LNBs requires more outage time, a larger capital investment, and is much more complicated than it is for a wall-fired boiler. Installing LNBs into a down-fired boiler requires:

- Modifying new burners for vertical operation.
- Replacing all of the roof tubes.
- Modifying the ductwork to accommodate ducts that go into the roof.
- Removing insulation, which may contain asbestos.
- Replacing the windbox.
- Rerouting the coal and gas piping.
- Modifying significantly the control system.

2.2 Low-NO_x Combustion System at Arapahoe Unit 4

This section describes the retrofit of the LNBs and OFA ports to Arapahoe Unit 4. In addition, it briefly describes the process flow and operation of the low-NO_x combustion system at Arapahoe Unit 4.

2.2.1 Retrofit of Low-NO_x Burners

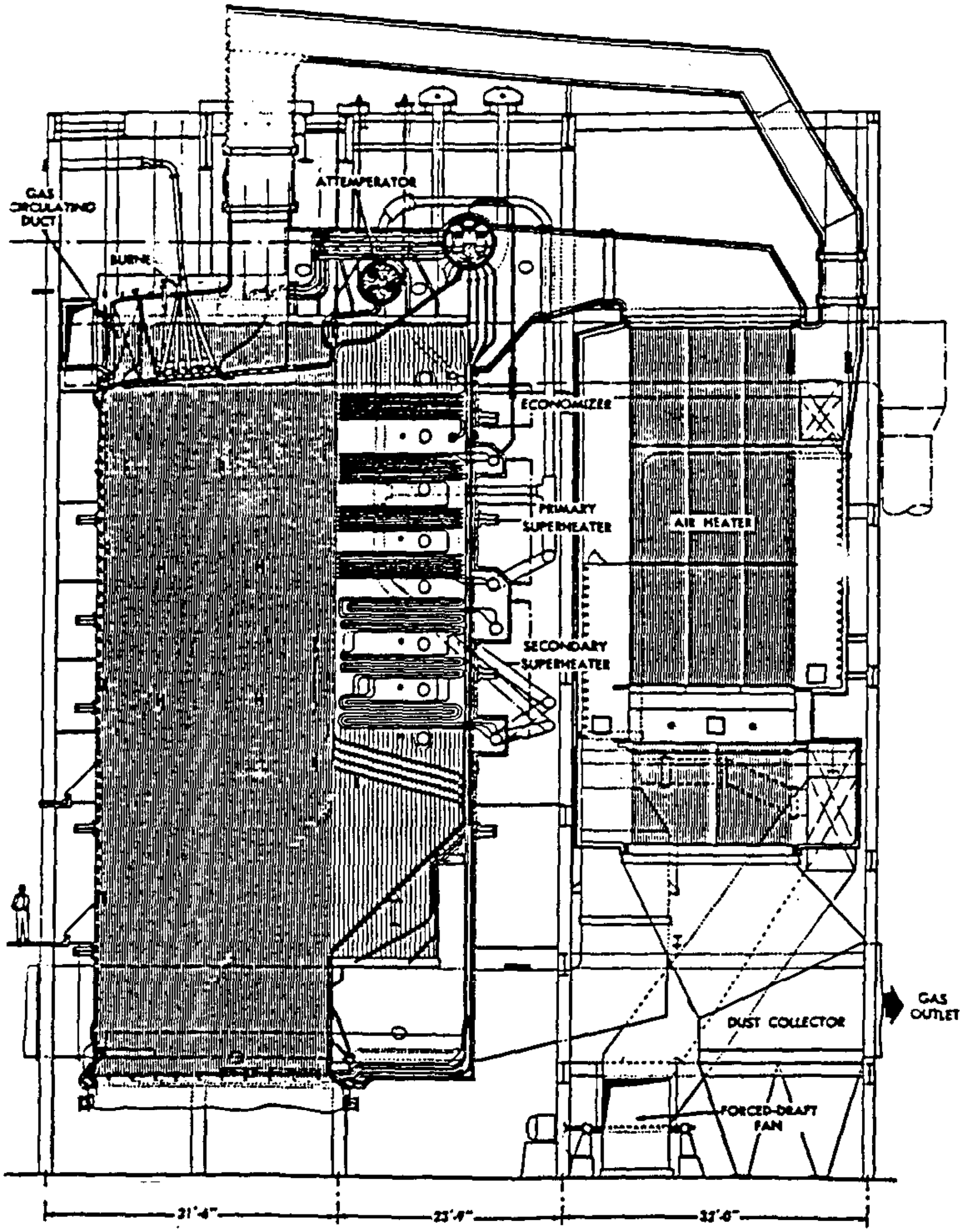
DRB-XCL™ burners are designed to be fired horizontally. Modifications are required to avoid mechanical problems when they are installed for down-firing. The sliding dampers were designed to operate horizontally and when mounted vertically for down-firing, the sliding dampers have to be lifted and overcome their own weight. For horizontal operation, these dampers are supported at a point that would not evenly support the sliding damper and would cause the damper to bind during operation. Therefore, the support structure for the sliding damper was redesigned to support the sliding damper evenly and operate smoothly. After a prototype was built and tested, this modification was incorporated into the burners retrofitted to Arapahoe Unit 4.

2.2.1.1 Original Burner Configuration

Figure 2-3 shows an elevation view of the Arapahoe Unit 4 boiler. Downstream of the burners, the flue-gas flows down the furnace and then turns upward to flow through the convective sections on the boiler backpass. After reaching the burner-level elevation, the flue-gas passes through the horizontal duct and is then directed downward through a tubular air heater. After leaving the air heater, the flue-gas passes through a reverse air FFDC to control particulate emissions. Induced-draft (ID) fans are positioned downstream of the FFDC and deliver the flue-gas into a common stack for Units 3 and 4.

The design of the original intertube-burners is not comparable to that of the more common wall-fired burners. The original furnace configuration was a down-fired system that employed 12 intertube burners located on the roof and arranged in one row across the width of the furnace. The secondary-air feeder duct and windbox were modified to accommodate the new burners and burner arrangement.

Each burner consisted of a duct split into 20 nozzles arranged in a four-by-five rectangle that injected the mixture of coal and primary air evenly across the furnace roof. A secondary air windbox surrounded each burner and allowed air to flow around each of the coal nozzles resulting in a checkerboard pattern of coal/primary air and secondary air streams. The burners had no provision to control the mixing rate of the coal/primary air and secondary air.



PUBLIC SERVICE COMPANY OF COLORADO
ARAPAHOE STATION - BOILER NO. 4
B & W CONTRACT NO. RB-219

RB-219-501-2

Figure 2-3. Elevation View of Arapahoe Unit 4

The LNBs required much larger openings in the roof tubes than the small openings required by the intertube burners. Accommodating the LNBs required the removal of everything from the boiler roof tubes to the roof of the boiler enclosure including the windbox, the coal and gas piping, and the secondary air supply duct. It also required the installation of new roof tubes. The new burners were placed in four rows of three burners.

As was shown in Figure 2-3, the secondary air duct originally entered the windbox at the rear (south side) of the furnace roof. As the new burners required significantly more roof area than the intertube burners, there were now four burners where the secondary air duct was originally located. To provide secondary air to the windbox, four pantleg ducts were added.

Because of the limited space, however, these ducts could not be made large enough to carry all of the secondary air, so additional ductwork was required. The boiler at Arapahoe Unit 4 was originally designed to use flue-gas recirculation (FGR) to control the steam temperature. At the time of the retrofit, the FGR system was no longer in use. Two abandoned FGR ducts that entered the front (south) wall of the windbox were used to provide the balance of the secondary air. Figure 2-4 shows Arapahoe Unit 4 retrofitted with the low-NO_x combustion system.

2.2.2 *Retrofit of OFA Ports*

B&W performed a numerical modeling study to determine the optimum size and location for the OFA ports which were installed about 20 feet below the boiler roof: three ports on the east side and three ports on the west side of the boiler. In addition to the OFA port assemblies, new ductwork, boiler-tube panels, and windboxes were installed for the OFA ports. The OFA ports were designed to inject up to 25% of the total secondary air through the furnace sidewalls.

The OFA ports are located in a small windbox on each side of the furnace. New ductwork was added to direct secondary air from the boiler roof to the sidewalls. Each of the ducts that supply OFA to the windboxes contains an opposed blade louver damper to control the flow of

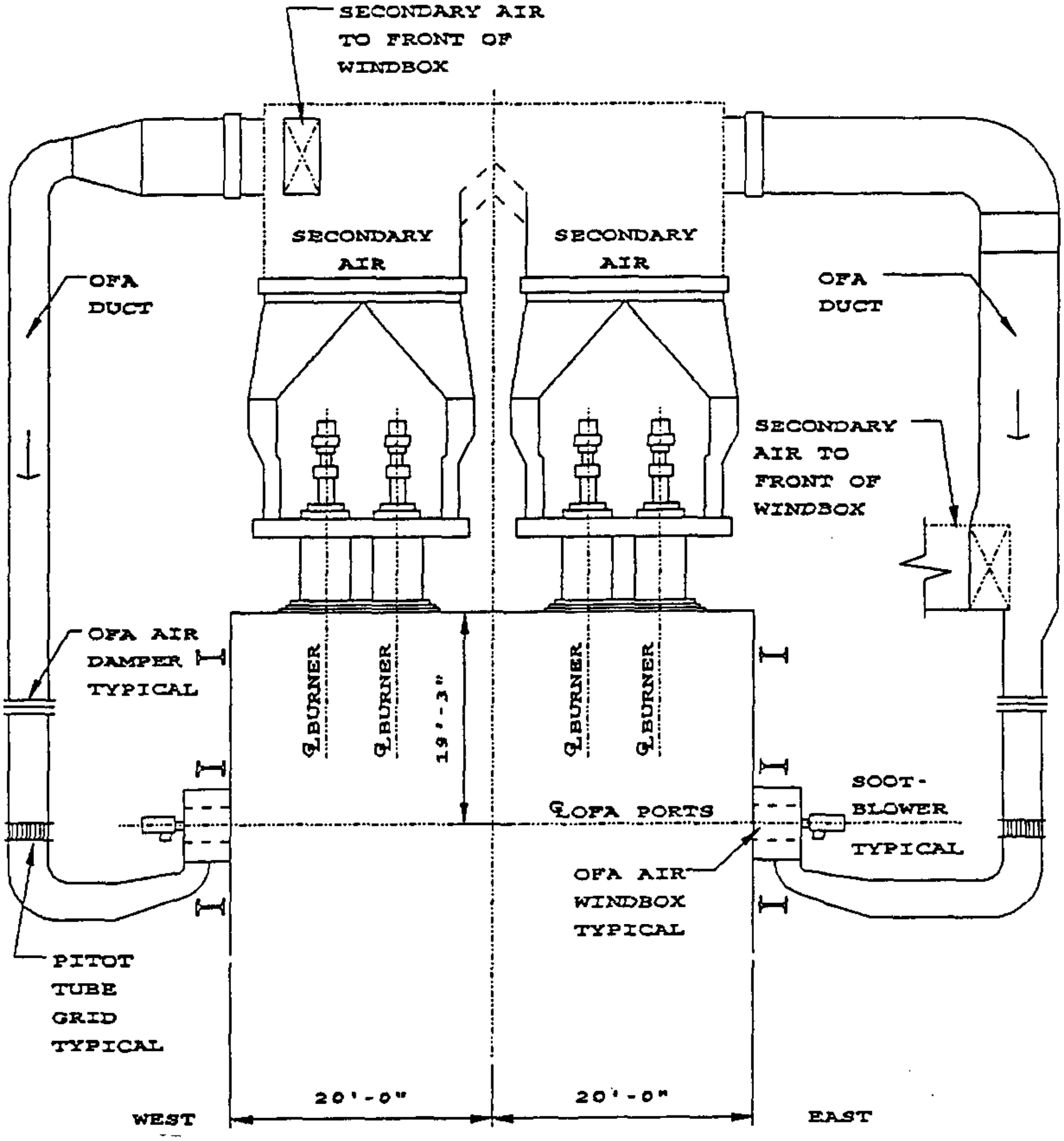


Figure 2-4. Front Sectional View of Upper Furnace (Looking North)

OFA, and a pitot-tube grid with a flow straightener to measure the total flow of OFA to each side of the furnace. Originally, two sootblowers were located on each side of the furnace at the location chosen for the OFA ports. Because of this, the sootblowers were lengthened to accommodate the depth of the new windboxes and relocated slightly.

The secondary air feeder duct and windbox were modified to accommodate the new burners and their arrangement. In addition to the OFA port assemblies, new ductwork and windboxes were also installed for the OFA ports. To accommodate the throats of the OFA ports, new boiler-tube panels were installed.

2.2.3 Process/Operation of Low-NO_x Combustion System

The coal piping supplies pulverized coal and primary air from the pulverizer to its respective burners. Secondary air is gradually introduced to the products of combustion further along the flame to complete combustion. This staged combustion reduces the flame intensity and minimizes NO_x formation.

The forced draft (FD) fan provides secondary air to the air heater, which preheats it. The main secondary air flow meters then measure the total flow of the preheated secondary air to the plenum. The plenum then distributes the preheated secondary air to the burner windbox and OFA port windbox.

The NO_x ports are located in a very hot zone of the furnace and are exposed to a significant amount of radiant heat. Providing sufficient cooling air is very important to the protection of the NO_x ports. Two thermocouples mounted on each port monitor locally the temperatures of the inner- and outer-air zones. Keeping the temperatures of the ports below their design metal temperature of 1,300 F requires the injection of about 10% of the combustion air.

Figure 2-5 shows the process flow diagram for the low-NO_x combustion system (LNBs and OFA ports).

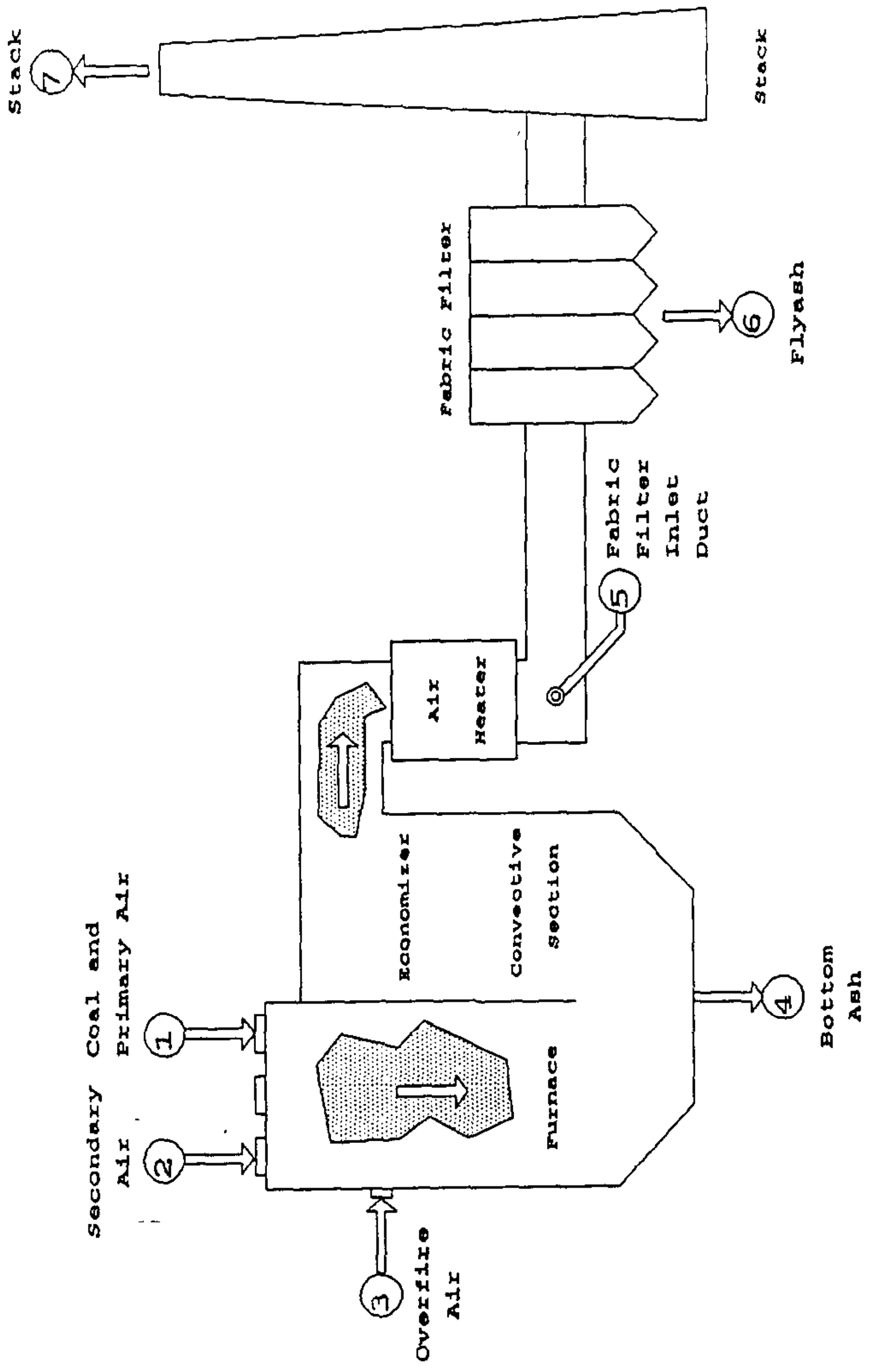


Figure 2-5. Process Flow of Low-NO$_x$ Combustion System

2.3 Test Program Objectives

The objectives of the LNB test program were to: (1) determine the effect of the combustion system and furnace variables on NO_x emissions and boiler performance, (2) determine the optimum combustion system parameters for daily operation, and (3) document day-to-day performance.

The LNB/OFA test program consisted of three separate phases. During the first, optimum operating conditions and settings for the burners and OFA ports were identified. The second phase consisted of a detailed series of tests to assess the performance of the low-NO_x combustion system as a function of various operating parameters. These parameters included boiler load, excess air level, OFA flow rate, and number of mills in service. These parameters represent the primary factors influencing NO_x, CO and fly ash carbon levels. Following the completion of the base-loaded optimization and parametric tests, the boiler was operated for two months (November and December 1992) under normal load following conditions. During this time, emissions data were automatically collected with the Continuous Emissions Monitor (CEM). Additional details of these tests and measurements can be found in "Integrated Dry NO_x/SO_2 Emissions Control System, Low-NO_x Combustion System Retrofit Test Report", Smith, et al., 1993.

2.4 Test Program Methodology

Low NOx combustion testing was performed in two different phases, a parametric test and a long term monitoring test. Parametric testing was performed by carefully setting the boiler and burner parameters followed by specific measurements of boiler operating conditions and emissions. The long term testing acquired boiler emissions and a limited amount of boiler operating data by an automatic emissions monitoring system, without interference from test personnel.

2.4.1 Instrumentation

2.4.1.1 Gas Analysis

An Altech 180 CEM system was purchased as part of the Integrated Dry NO_x/SO_2 Emissions Control System and installed during the low-NO_x combustion system retrofit. The CEM system utilizes a Perkin Elmer MCS 100 infrared gas analyzer which is capable of continuously analyzing eight gas species simultaneously, using a combination of gas filter correlation and single-beam dual-wavelength techniques. Table 2-1 provides a listing of the full scale range, measurement technique, and interfering species for each of the gases measured.

The MCS 100 was configured to measure NH_3, which imposes special requirements upon the design of the CEM sampling system. In order to maintain the integrity of the sample, the entire sampling system (probe, sample line, pump, flowmeter, and sample cell) must be maintained at 230°C (445°F). Due to these heat tracing requirements, the CEM system was configured to sample from only two different single-point locations; at the exit of the air preheater in the duct leading to the FFDC, and downstream of the FFDC and induced draft fans.

Measured Species	Range	Measurement Technique	Interfering Species
NO	0-800ppm	Gas Filter Correlation	H_2O
CO	0-500 ppm	Gas Filter Correlation	H_2O
SO_2	0-800 ppm	Single Beam Dual Wavelength	NH_3, H_2O
NO_2	0-100 ppm	Single Beam Dual Wavelength	NH_3, SO_2, H_2O
CO_2	0-20 volume %	Single Beam Dual Wavelength	H_2O
H_2O	0-15 volume %	Single Beam Dual Wavelength	None
N_2O	0-100 ppm	Single Beam Dual Wavelength	CO, CO_2, H_2O
NH_3	0-50 ppm	Gas Filter Correlation	CO_2, H_2O

Table 2-1. Gas Species Measured by Perkin Elmer MCS 100 Analyzer

In order to obtain a representative composite gas sample, as well as provide the ability to look at discrete areas of the flue-gas flow, Fossil Energy Research Corp. (FERCo) provided a sample gas conditioning system which allowed sampling from additional unheated sample probes. Rotameters were used to balance the individual flows in order to provide an accurate composite sample which was supplied to the Altech CEM for analysis. A grid of twelve unheated sample probes were located at the economizer exit, a six probe grid was located at the exit of the air preheater, and one probe in the FFDC outlet duct leading to the stack.

2.4.1.2 Fly Ash Carbon Measurements

Fly ash sampling was performed by extracting a composite high volume sample from the air heater exit location. The fly ash analyses were performed on site utilizing a Loss on Ignition (LOI) analyzer developed by FERCo for the specific purpose of providing a rapid turnaround of the data. This portable instrument can provide fly ash LOI values in a matter of 15 to 30 minutes. These on-site measurements were verified by separate analysis by an outside laboratory.

2.4.1.3 Furnace Exit Gas Temperature Measurements

Furnace exit gas temperature (FEGT) measurements were made using both acoustic pyrometry and suction pyrometry (high velocity thermometry, (HVT)). An acoustic pyrometry system, manufactured by Combustion Developments Ltd. of England, was utilized to provide a continuous assessment of the furnace exit gas temperatures. The acoustic temperature measurement technique requires a clear line of sight across the furnace at the measurement location, and measures an average gas temperature along this line of sight. The HVT probe utilized for these measurements was of a standard water-cooled design, utilizing a single radiation shield and a type R thermocouple.

2.4.1.4 Particulate Size Distribution Measurements

A University of Washington Pilat Mark V cascade impactor with a right angle precutter was used to obtain the FFDC inlet particulate size samples. The impactor has a maximum aerodynamic cutpoint of 15.9 microns. In order to obtain the size distribution above the maximum cutpoint, the data are extrapolated with a standard impactor cubic spline fit program. During the baseline tests, a program supplied by the University of Washington was used to provide the extrapolation. Subsequently, the program pcCIDRS (written by J. McCain of Southern Research Institute) has been released and is becoming regarded as the best impactor spline fit program available. The post-retrofit particulate size data were reduced using the pcCIDRS program, and in order to provide an accurate basis for comparison, the baseline data were rerun through the same program.

2.4.2 Test Methods

Parametric testing was performed by carefully controlling the various burner and boiler variables in a systematic manner, to determine their effect upon boiler operation and emissions. Key boiler variables included:

- Boiler load
- Number of mills in service
- Excess air levels
- Burner adjustments and controls
- OFA adjustments and controls

Once the desired test conditions were obtained, the unit was allowed to stabilize to insure steady state operation prior to the start of a test. During the test period, documenting the boiler operation was performed by completing a boiler control room data sheet from the Distributive Control System (DCS) control screens, and obtaining a boiler composite set of gaseous emissions. Following the completion of the data collection, additional adjustments to the boiler or burner variables were performed and the process was repeated. Additional test data was obtained, as required by the specific text objectives. These additional measurements include:

- Detailed gaseous measurement traverses
- Fly Ash LOI
- Furnace Exit Gas Temperatures
- Particulate data

Long-term monitoring was performed by analyzing the boiler and emissions data recorded by the CEM monitor. In addition to the boiler average gaseous emissions, the CEM also logged the boiler load data. Boiler operation was not controlled by the testing contractors and was allowed to follow dispatch requirements from the various control operations. The purpose of the long-term tests was to document and verify boiler emissions under normal operations.

2.4.3 Quality Assurance/Quality Control

2.4.3.1 Gas Analysis

A Relative Accuracy Test Audit (RATA) was performed to verify the accuracy of the CEM system in accordance with the requirements established in 40 CFR, Part 60, Appendices A and F, and the results are summarized in Table 2-2. All individual parameters were found to be within the acceptance criteria.

Parameter	Relative Accuracy (%)
CO_2 (%, wet)	2.64
Moisture (%)	7.86
O_2 (%, wet)	17.81
NO (ppm, wet)	1.53
NO (lb/MMBtu, wet*)	5.93
NO (ppm, dry)	1.02

Table 2-2. CEM RATA Results

* Calculated on an O_2 basis

2.4.3.2 Fly Ash LOI Measurements

A large number of fly ash samples were also submitted to the PSCC laboratory for LOI analysis to verify the performance of the on-site instrument. The results showed a good correlation between the two methods, with the on-site instrument providing slightly higher values than those from the PSCC laboratory.

Select fly ash samples obtained during the baseline tests were also sent to the independent laboratory in order to provide a means of correlating the elemental carbon and LOI analysis data. The LOI analyses overpredicted the elemental carbon content of the fly ash samples. This is to be expected since an LOI analysis is not carbon specific. Over the range of LOI from two to six percent, the on-site LOI instrument tended to overpredict the elemental carbon content of the fly ash by approximately 1.3 to 1.7 percent.

2.4.3.3 Furnace Exit Gas Temperature Measurements

In order to verify the acoustic temperature measurement data, HVT measurements were made at selected operating conditions. A good correlation between the acoustic temperature measurement and the HVT resulted from this comparison.

2.5 Low NO_x Combustion Results

The operating variables which were examined during the parametric performance tests of the retrofit low-NO_x combustion system were boiler load, excess air level, OFA flow rate, and mills out of service. These test parameters represent the primary factors influencing NO, CO and carbon emissions. The effect of each parameter is discussed in the following subsections.

2.5.1 Effect of Boiler Load

The NO emissions as a function of boiler load with the retrofit combustion system are compared to those measured with the original burners in Figure 2-6. Unless otherwise noted, the data presented in this, and the following sections, for loads of 80 MWe and above are with all four mills in operation. The 60 MWe data are with three mill operation, while the 50 MWe data were obtained with two mills in service.

NO emission data for the retrofit combustion system with both minimum and maximum OFA flow rates are presented in Figure 2-6. Maximum OFA is defined as having the OFA flow control dampers full open. This corresponds to approximately 24 percent of the total secondary air at boiler loads of 80 MWe and above, and 28 and 32 percent for 60 and 50 MWe, respectively. Minimum OFA flow is defined as the minimum amount necessary to maintain the OFA port metal temperatures at an acceptable level. At 80, 100 and 110 MWe, 15 percent of the total secondary air was sufficient. Minimum OFA tests were not performed below 80 MWe.

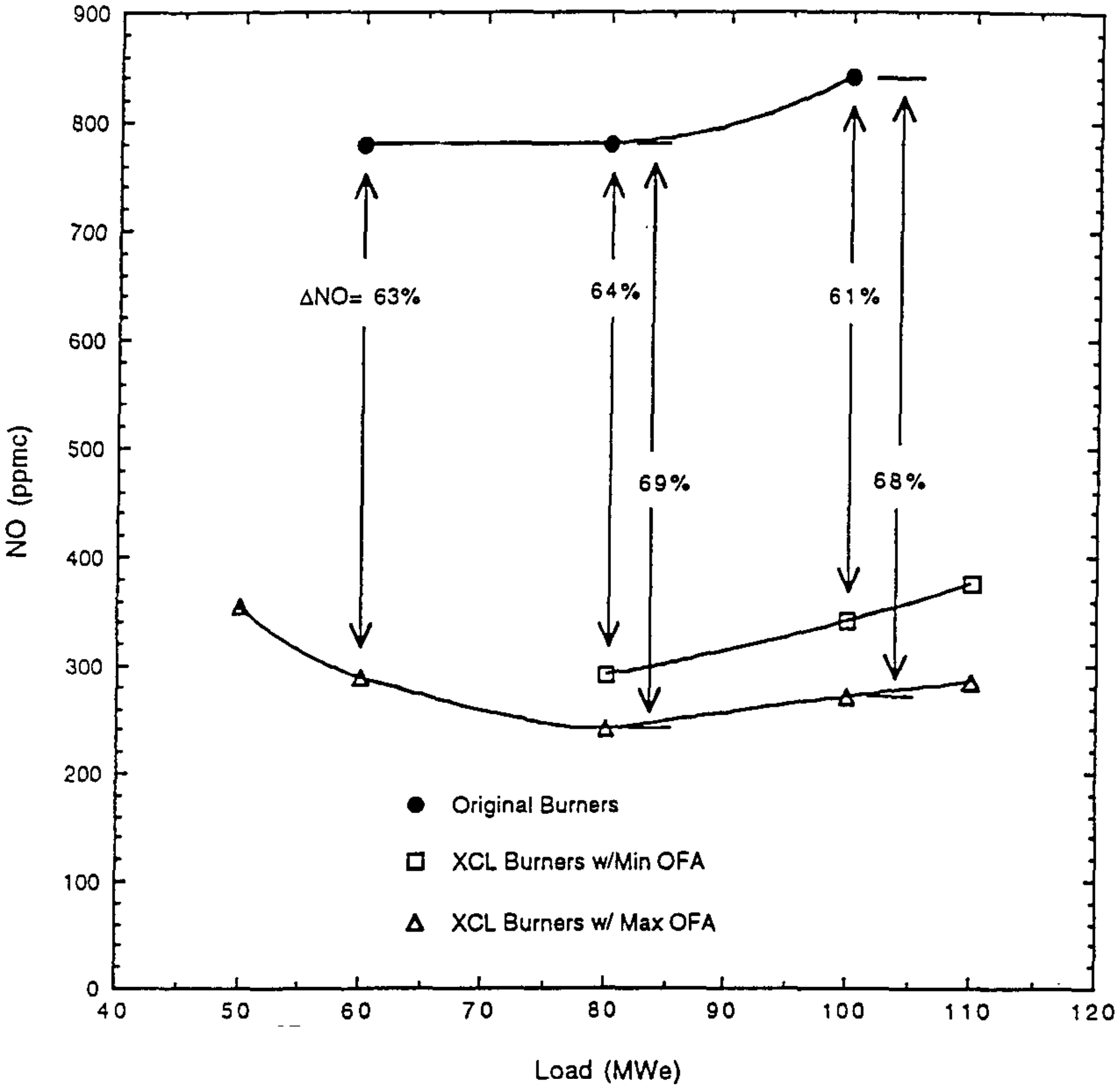


Figure 2-6. Pre- and Post-Retrofit NO Emissions as a Function of Boiler Load

The data show that with maximum OFA, the NO reduction varies from 63 to 69 percent across the load range of 60 to 100 MWe. With minimum OFA, the NO reduction is only slightly lower, indicating that for this particular installation, the LNBs appear to provide the majority of the reduction in NO emissions. Due to OFA port temperature limitations, it was not possible to reduce the OFA flow to zero, so minimum OFA remains 15 percent of the secondary air.

Figure 2-7 shows a comparison of CO emissions before and after the retrofit. The data indicate that CO emissions were actually reduced with the new burners and maximum OFA, especially at or below 80 MWe. A factor contributing to this decrease is that at reduced load, the boiler must be operated at higher excess air levels than previously required with the original burners. Before the retrofit, it was necessary to increase the excess air slightly as load was reduced in order to maintain design steam temperatures. With the new combustion system, the air flow increase necessary to maintain steam temperature was found to be significantly greater.

Figure 2-8 compares the boiler O_2 levels necessary to maintain both adequate steam temperature and limit CO emissions to 50 ppm, for the retrofit combustion system, and for the original burners. With maximum OFA, 50 ppm CO was achieved at 100 MWe with an excess air level similar to that necessary with the original burners. However, as mentioned above, as boiler load is reduced, it was necessary to increase the excess air levels in order to maintain steam temperatures. With maximum OFA, this increase in boiler O_2 was approximately 0.7 percent at 80 MWe and 1.9 percent at 60 MWe.

The penetration of the OFA was found to be a critical factor in assuring adequate oxygen for sufficient carbon burnout at the center of the furnace, near the division wall. This effect is again apparent when reviewing the CO and O_2 data with minimum OFA. As seen in Figure 2-7, CO levels were in general lower with maximum OFA. As the overfire flow was reduced, the penetration and mixing was also reduced, and an increase in excess air was necessary to maintain CO levels at 50 ppm. Similarly, higher excess air levels were required for the minimum OFA test in Figure 2-8, in order to maintain CO levels below 50 ppm at loads between 80 and 100 MWe.

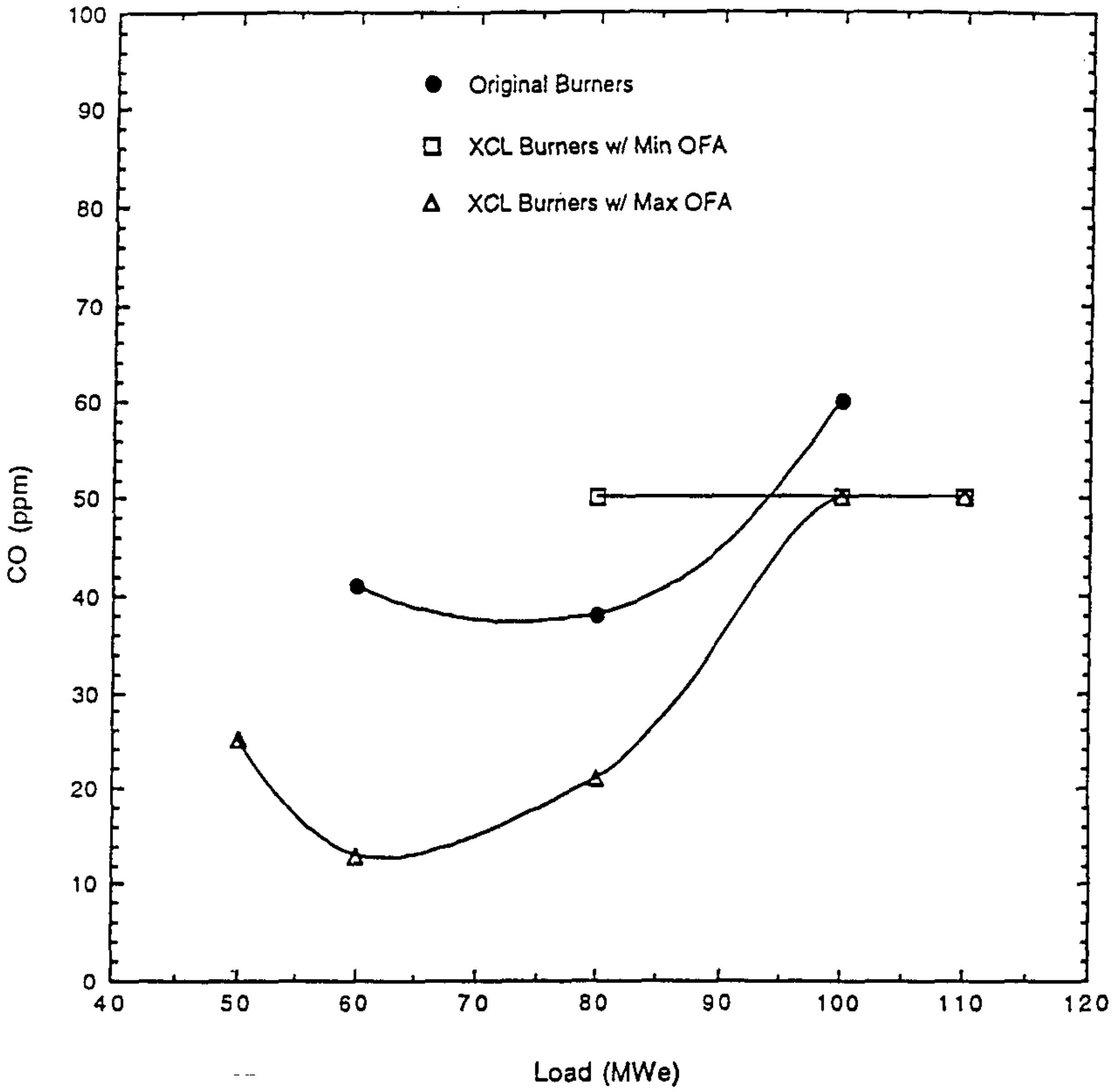


Figure 2-7. Pre- and Post-Retrofit CO Emissions as a Function of Boiler Load

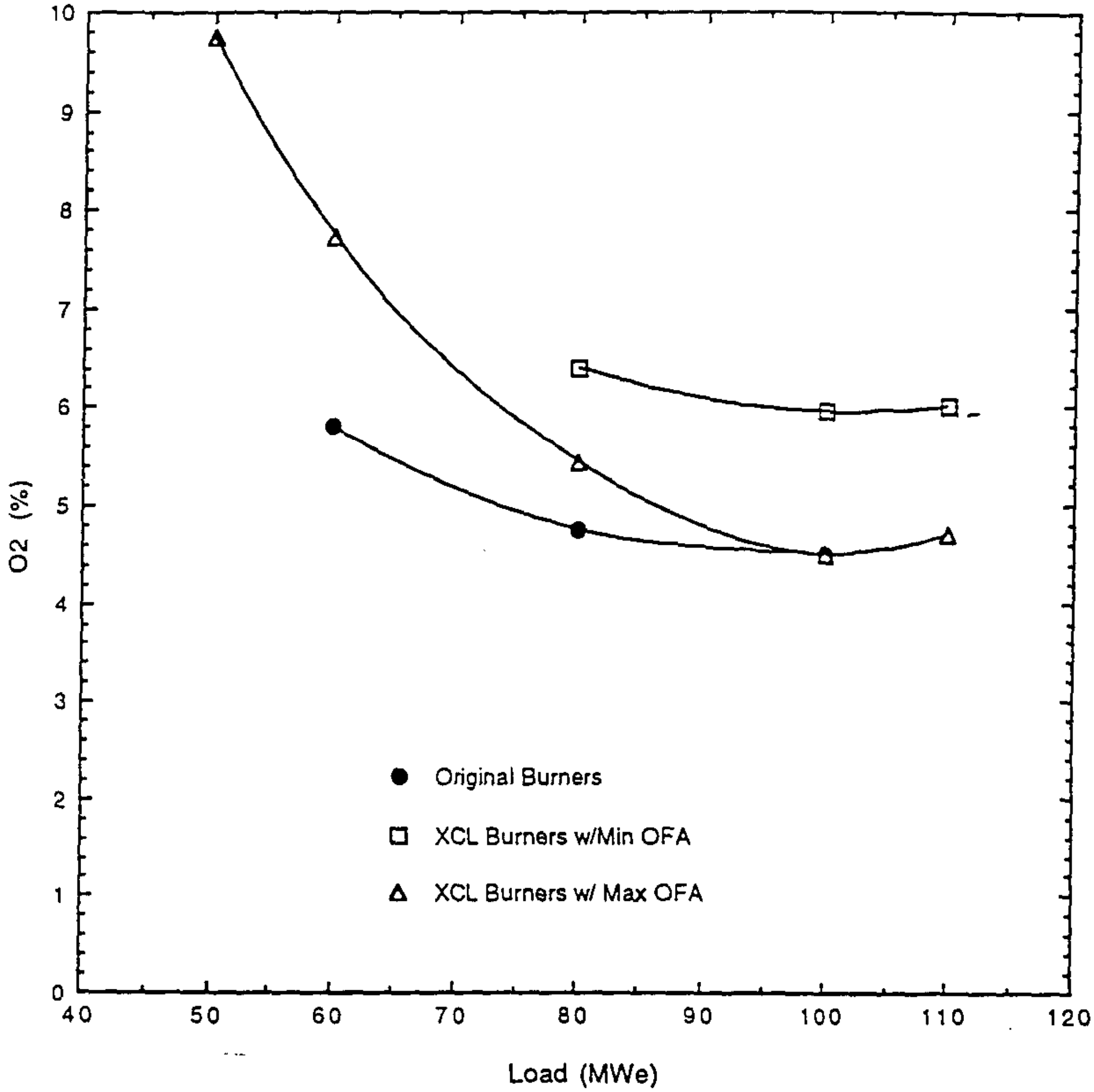


Figure 2-8. Pre- and Post-Retrofit Excess O_2 Levels for Normal Operation as a Function of Boiler Load

A comparison of the fly ash carbon levels before and after the retrofit are presented in Figure 2-9. The data show that the combustion modifications did not significantly increase carbon levels above the baseline test results.

The post-retrofit LOI data show a general downward trend as boiler load is reduced, which was consistent with the trend seen for the CO emissions. However, an increase in both CO emissions and fly ash carbon content was seen when load was reduced from 60 to 50 MWe, and was likely the result of changing from three mill to two mill operation. The fly ash carbon levels were lowest with minimum OFA.

2.5.2 Effect of Excess Air Level

The effect of operating O_2 level on NO emissions is shown in Figure 2-10 for both the original and retrofit combustion systems. The data show that the NO emissions were significantly more sensitive to changes in O_2 before the low-NO_x combustion system was installed. With the original burners, a one percent change in O_2 resulted in approximately a 145 ppmc change in NO. With the LNBs, the sensitivity is on the order of 40 ppmc NO per percent of O_2. This decreased sensitivity to O_2 is attributed to a more gradual mixing of fuel and air in the near burner region. It does not appear that the amount of OFA has a significant effect on the NO/O_2 sensitivity, as the results shown in Figure 2-10 include the data for all overfire flow rates tested at each particular load.

The recommended economizer exit and control room O_2 levels, in order to maintain adequate steam temperatures and minimize NO, CO, and fly ash carbon levels, are shown in Table 2-3 as a function of boiler load.

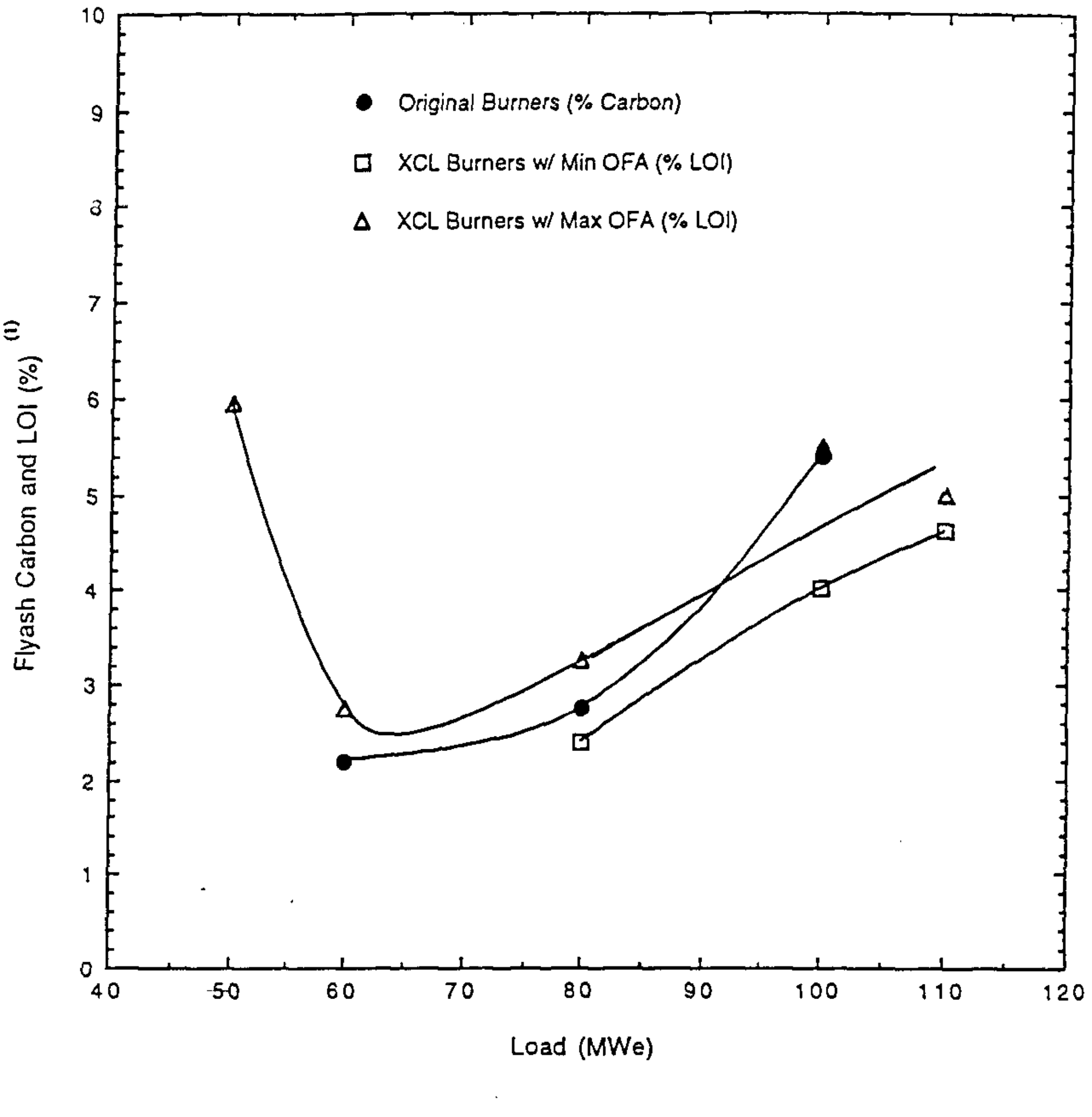


Figure 2-9. Pre- and Post Retrofit Fly Ash Carbon Levels as a Function of Boiler Load (Note: original burners plotted as ash carbon and the LOI analyses tend to be higher than the elemental carbon content by 1.3 to 1.7 percent)

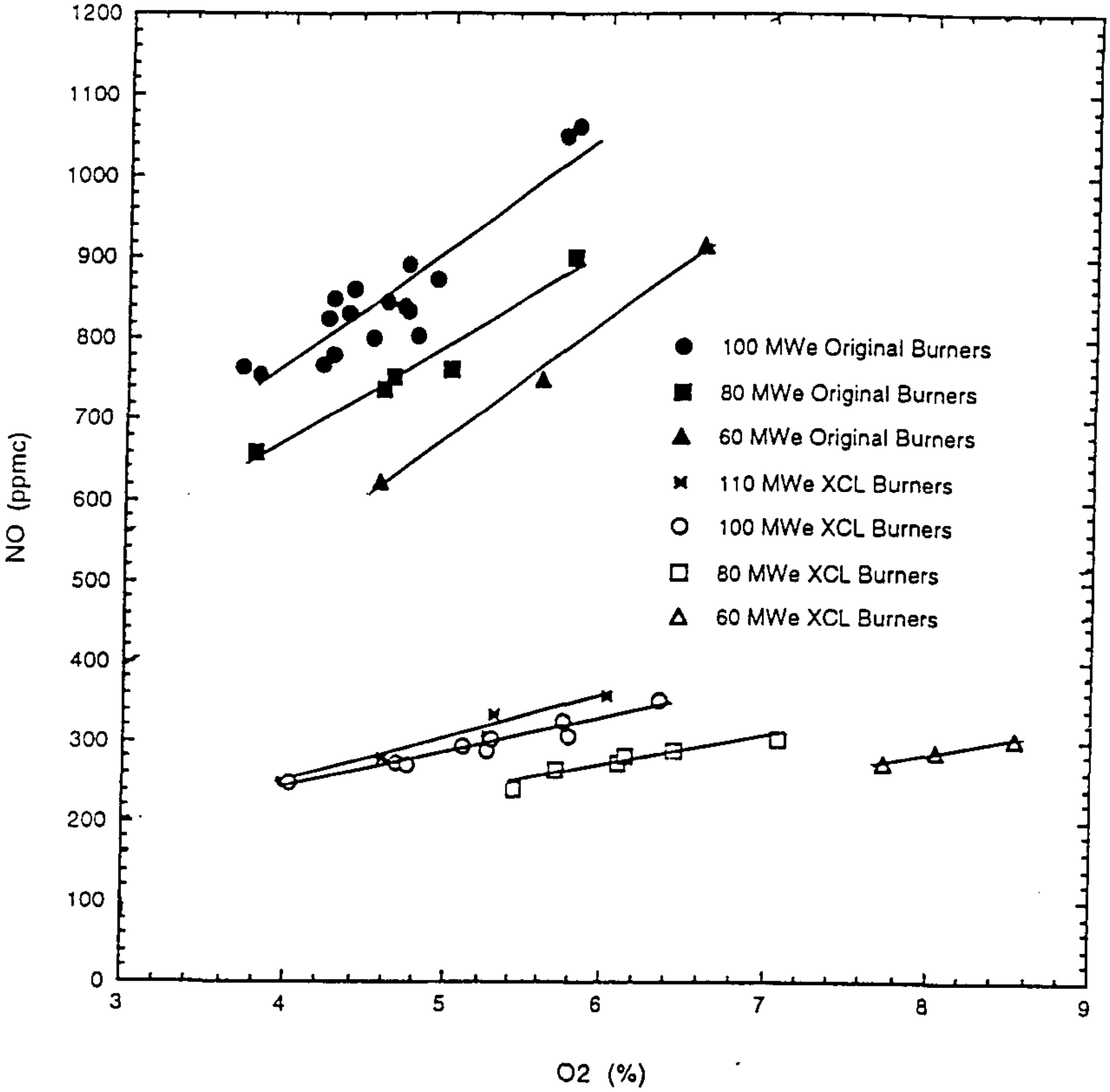


Figure 2-10. Effect of Boiler O_2 on Pre- and Post-Retrofit NO Emissions

	Retrofit Combustion System		Original Burners	
Load (MWe)	12-point Economizer Exit O_2 (%, dry)	Control Room O_2 (%, wet)	12-point Economizer Exit O_2 (%, dry)	Control Room O_2 (%, wet)
110	4.7	3.6	---	---
100	4.5	3.4	4.5	3.6
80	5.4	4.3	4.8	3.9
60	7.7	6.5	5.8	5.1

Table 2-3. Recommended O_2 Levels as a Function of Boiler Load

2.5.3 Effect of Overfire Air (OFA)

The previous discussions included OFA flow variations with other boiler operating variables. The following is a brief synopsis of the key OFA results. OFA is generally expected to provide a significant NO reduction in addition to that achieved with LNBs alone. However, the results shown in Figure 2-6 indicated only a modest effect of OFA flow on NO emissions, which suggests that, for this particular retrofit, the burners are responsible for the majority of the reduction in NO emissions.

In addition, although increasing OFA is generally expected to increase CO emissions and fly ash carbon levels, quite the opposite was found to be true for this particular installation. The data show that at 80 to 110 MWe loads, increasing the OFA at a fixed boiler O_2 level results in decreased CO emissions and fly ash carbon levels. It is believed that the increase in penetration and mixing provided at the higher OFA flows eliminates any locally fuel rich regions where carbon burnout would be impeded. Based on the results of the parametric evaluation of the effect of OFA flow rate, the maximum OFA flow condition was recommended throughout the boiler load range because this condition resulted in the lowest NO and CO emissions, as well as the lowest O_2 requirement.

2.5.4 Effect of Mills Out of Service

The data reported thus far have been for four mill operation at boiler loads of 80 MWe and above, three mill operation (B Mill out of service) at 60 MWe, and two mill operation (A and D Mills out of service) at 50 MWe. A detailed characterization of the effect of mill in service pattern was conducted at 80 MWe with maximum OFA.

The mills in service pattern effect on NO emissions at 80 MWe is shown in Figure 2-11, where three mill operation with each of the four patterns is compared to operation with all four mills. Although the data show an effect of which mill is removed from service on NO emissions, the variation is small and on the order of only 10 percent.

However, both CO emissions and fly ash carbon levels are substantially higher for three mill operation relative to four mill operation. The increase in carbon losses seen with the switch from four to three mill operation is likely due to; (1) four mill operation provides a more uniform distribution of coal and air across the roof of the furnace, and (2) with one mill out of service, each of the three remaining mills process approximately 33 percent more coal than at the four mill condition.

2.5.5 Furnace Exit Gas Temperature Measurements

The results of the acoustic temperature measurements at the furnace exit are shown in Figure 2-12. The data collected with the optimized low-NO_x combustion system show that the gas temperatures decreased by approximately 170°F across the entire load range. This decrease was responsible for the additional excess air necessary to maintain steam temperature at reduced boiler loads and has also reduced the amount of steam attemperation required at full load.

HVT measurements were made through the same two ports utilized for the acoustic measurements in order to verify the data provided by the acoustic instrument. The verification tests were conducted on three separate occasions at boiler loads of 60, 80 and 110 MWe. The results of the verification tests showed that the acoustic measurement yielded a line of sight average temperature which is in good agreement with, albeit slightly higher than, the average

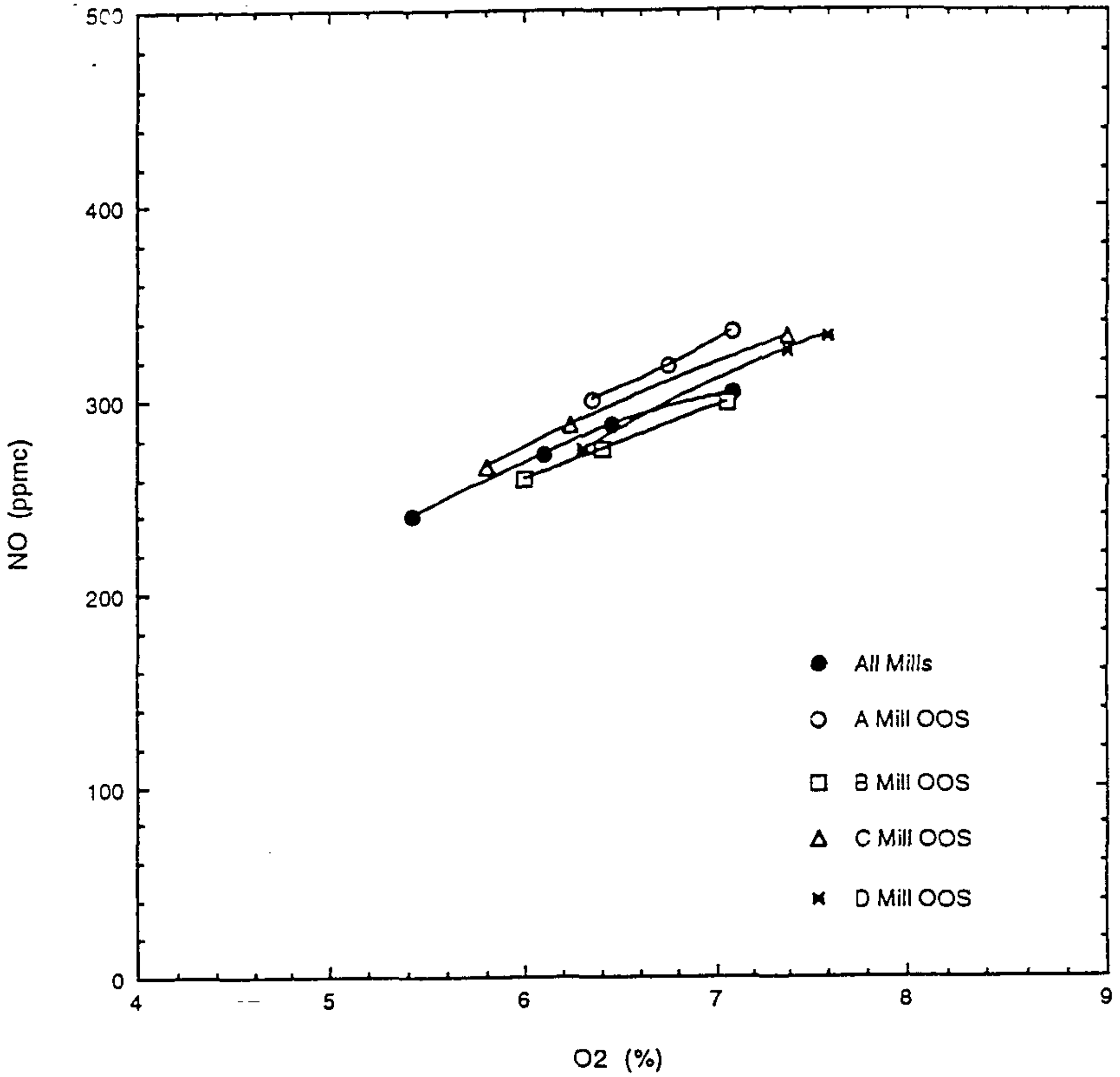


Figure 2-11. Effect of Mill in Service Pattern on NO Emissions at 80 MWe Load (Downstream of first screen tubes)

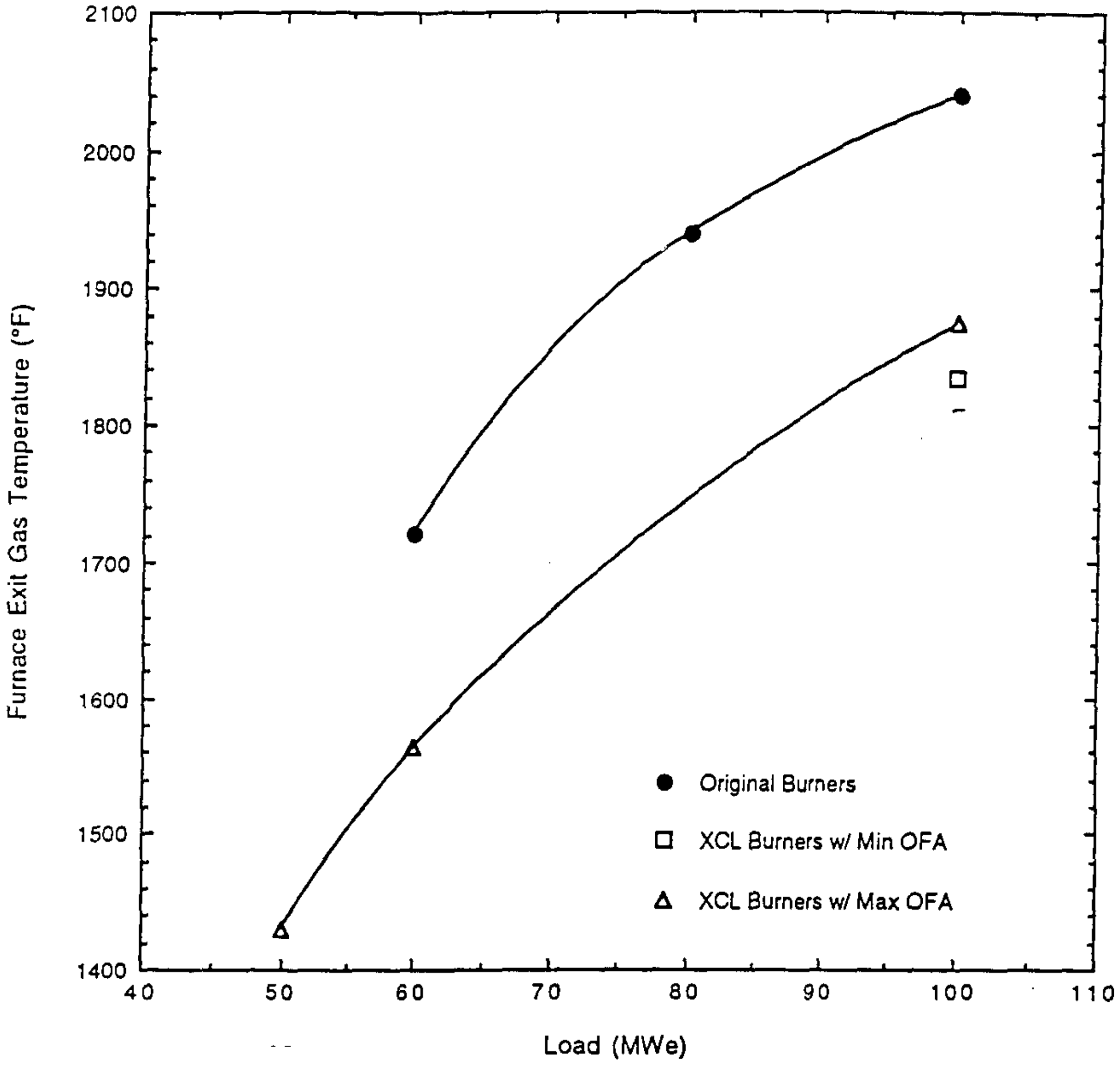


Figure 2-12. Pre- and Post-Retrofit Furnace Exit Gas Temperatures as a Function of Boiler

which may be inferred from the partial HVT traverses. The agreement between the two techniques is considered to be good.

Overall, it appears that the retrofit has resulted in a furnace gas exit temperature decrease on the order of 200°F. This has impacted the amount of excess air required to maintain steam temperature at reduced loads, and is also expected to impact the performance of the SNCR system.

2.5.6 Particulate Size Distribution Measurement

The average particle size distribution for the baseline tests, as well as those for the retrofit tests, with maximum and minimum OFA flow was measured with a cascade impactor at the FFDC inlet location. These measurements represent uncontrolled particulate size distribution from the furnace. Figure 2-13 shows the cumulative particle size distribution for three cases, the original burners and the retrofit low NO_x burners with minimum and maximum OFA. A decrease in the large particle size range (~100 micron) can be noted for the retrofit burner operation, relative to the original burners.

The mass mean diameter (MMD) for each condition can be determined from the cumulative particle size distributions. MMDs of 31, 26 and 18 microns were measured for the baseline burner, and minimum and maximum OFA cases, respectively. The decrease in MMD after the retrofit may be attributed to many different factors. The improved fuel/air mixing may have improved carbon burnout. Or, the decrease may also have been due to improved mill operation, since the mills were operating more consistently after the retrofit. Unfortunately, there is not enough data available to indicate precisely which effect is responsible.

2.5.7 Long Term Load Following

Following completion of the parametric tests, the boiler was operated for two months (November and December 1992) under normal load following conditions. There were no test personnel on site during this time, so data were collected automatically with the CEM.

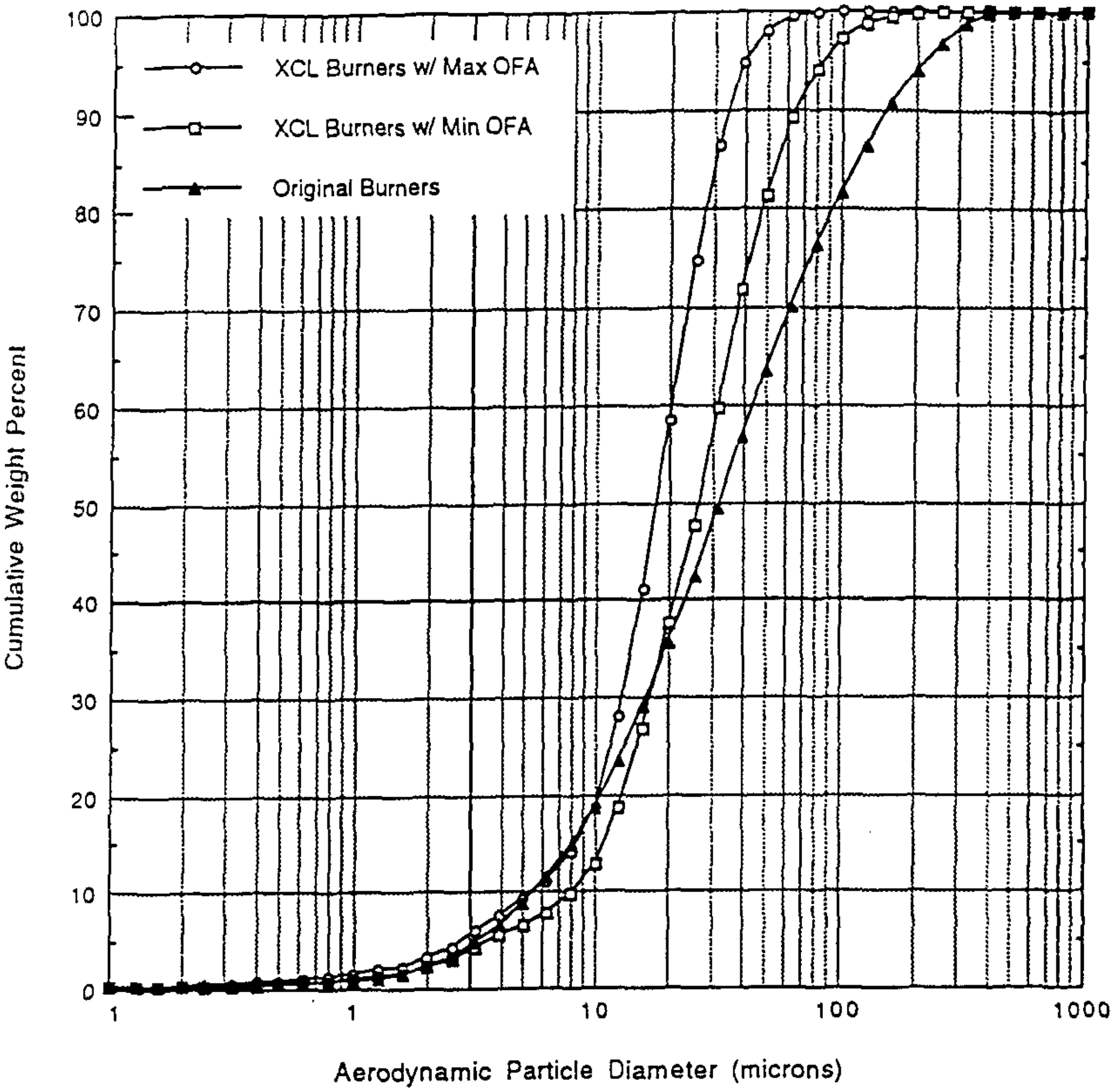


Figure 2-13. Pre- and Post-Retrofit FFDC Inlet Cumulative Particle Size Distributions at 100 MWe

Figure 2-14 shows a comparison of the NO emissions during parametric and load following operation. The CEM was programmed to record 10-minute averages for all the measured gas species, as well as boiler load, and the data were segregated into load groups of 10 MWe. In general, the data show that the NO emissions are 10 to 20 percent (30 to 60 ppm) higher under load following conditions. The increase is likely due to the higher boiler O_2 levels which are maintained during normal load following operation. The O_2 levels are 1 to 1.5 percent higher during load following operation. The NO/O_2 sensitivity with the new LNBs (40 ppmc NO per percent O_2) is most probably responsible for the increase in NO emissions.

Under load following conditions, CO emissions were also higher, particularly at full load. This is likely attributable to full load operation with three mills in service rather than four mills.

2.5.8 Natural Gas Firing

Arapahoe Unit 4 is generally fired with a Colorado low-sulfur bituminous coal, but has the capability to fire 100 percent natural gas. A brief series of tests (8 hours total test time) was conducted to ensure that the boiler could maintain full load with the retrofit combustion system, as well as document the NO and CO emissions under gas-fired conditions. As natural gas firing was not included as part of the test plan, baseline data with the original burners was not available for comparison.

Figure 2-15 shows the effect of boiler O_2 and OFA on NO emissions for gas firing at 100 MWe. Two things are noteworthy with natural gas firing compared to coal firing. First, with natural gas

for a given boiler O_2 level. This effect can be attributed to a more rapid mixing of fuel and air in the near-burner region. Second, the data also show that OFA has an effect on the sensitivity of NO emissions to changes in boiler O_2 (recall that with coal firing little effect was observed). At the minimum OFA condition, the sensitivity was on the order of 115 ppm NO per percent of O_2. When the OFA was increased to the maximum level, the sensitivity decreased to approximately 65 ppm per percent.

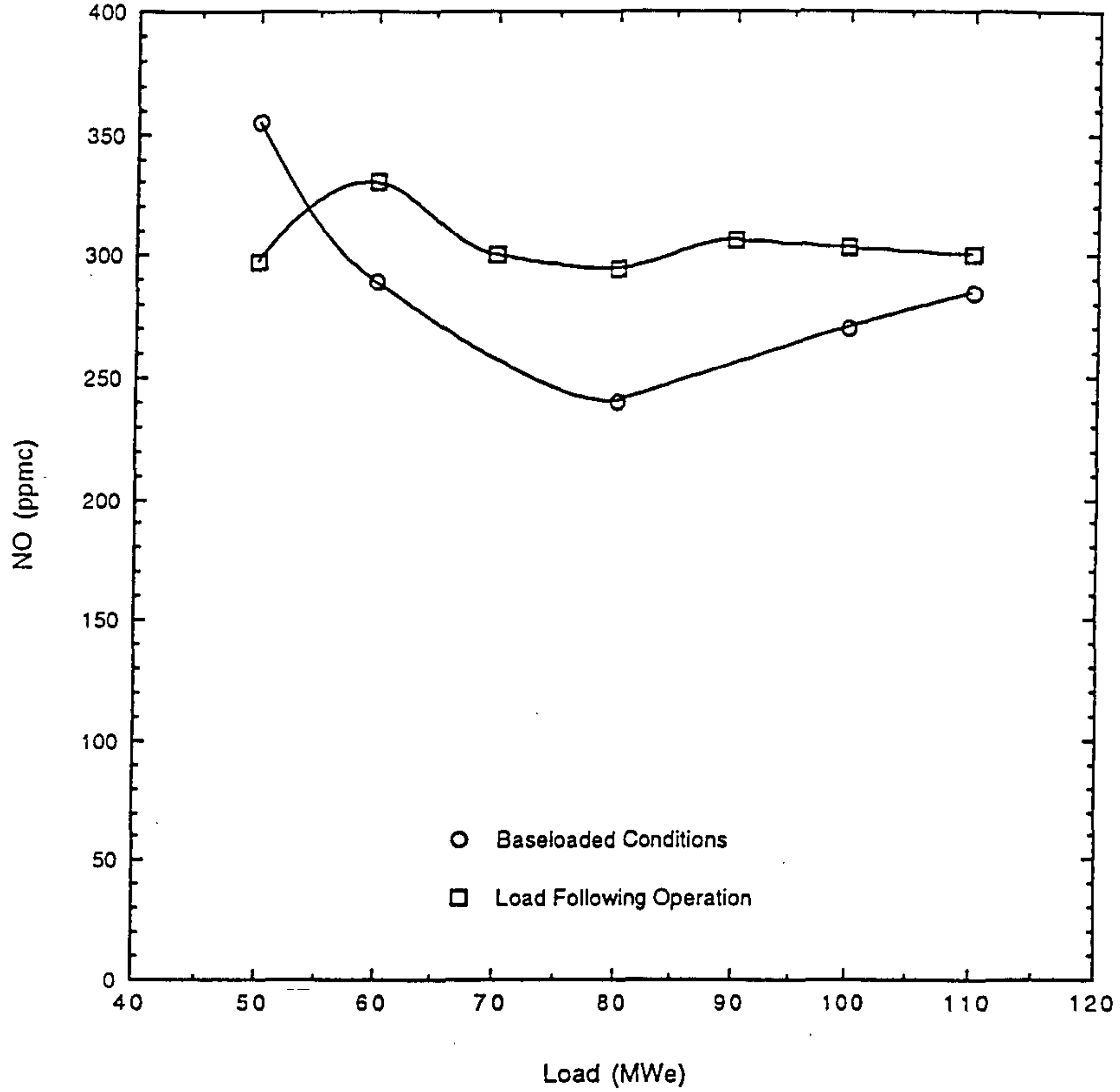


Figure 2-14. Comparison of NO Emissions for Base-Loaded and Load Following Operation

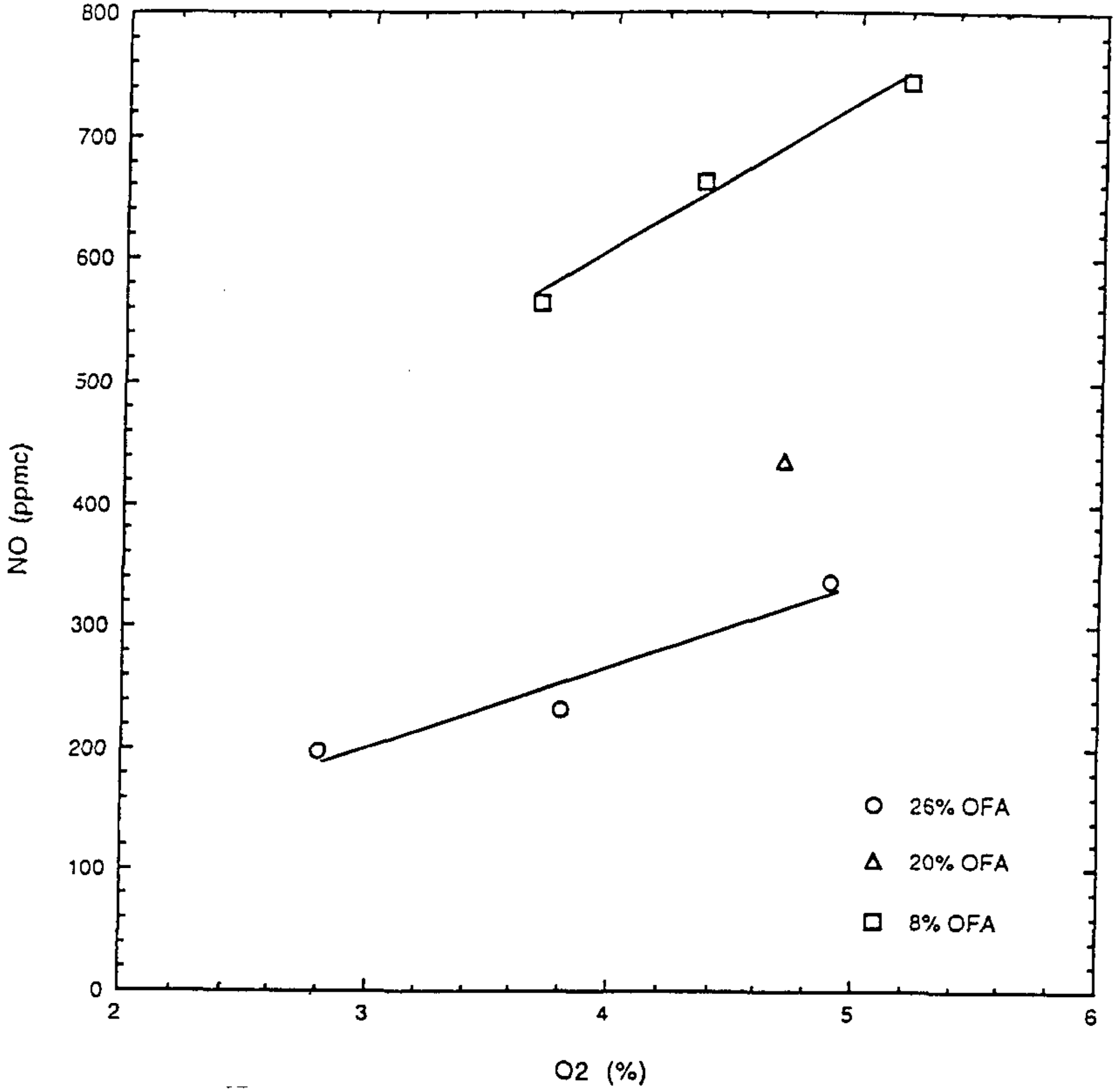


Figure 2-15. Effect of Boiler O_2 and Overfire Air on NO Emissions for Natural Gas Firing at 100 MWe

Additional data show that increasing the OFA at a fixed O_2 level results in increased CO emissions. However, the increase in CO emissions was very small in comparison to reduction in NO emissions, and therefore, maximum OFA still provides the "optimum" performance.

2.6 Environmental Performance

This section briefly summarizes the results from the environmental monitoring performed during the testing of the low-NO_x combustion system. The environmental monitoring was completed according to the *Environmental Monitoring Plan for the Integrated Dry* NO_x/SO_2 *Emissions Control System*, dated February 1992 and the *Environmental Monitoring Plan Addendum for Air Toxics*, dated July 1993.

Generally, the testing went well and there were no significant environmental events during the testing of the low-NO_x combustion system. Except for opacity, there were no excursions of any compliance monitoring. Opacity was in compliance over 99.98% of the six-months the low-NO_x combustion system was tested. The average opacity ranged from 3 to 4%.

A significant amount of supplemental monitoring was completed to define the emissions while operating and testing the combustion system retrofit. During this testing, it was found that the retrofit of the low-NO_x combustion system produced a very positive environmental impact. Depending on operating conditions, the retrofit reduced NO_x emissions by 62 to 69% without producing high emissions of carbon monoxide or high concentrations of unburned carbon in the fly ash.

Particulate emissions were very low, on the order of 0.001 grains/dry standard cubic foot (gr/DSCF). While this emission is slightly higher than the baseline of the original combustion system, it is believed that this slight increase is due to normal variations in FFDC collection efficiency and not due to a detrimental change of the combustion process.

Emissions of particulates smaller than 10 microns (PM_{10}) were tested during the combustion optimization, but a problem with the sample caused the loss of all condensable particle emissions. The non-condensable PM_{10} emissions were in the range of 0.00003 gr/DSCF and were approximately an order of magnitude lower than the baseline emissions. The sample time may not have been long enough to accurately determine the PM_{10} emissions due to the very high collection efficiency of the FFDC.

Data on 52 air toxics were also collected during the testing of the low-NO_x combustion system. Although there were a few problems in the collection and analysis of this data which raise some questions, a significant amount of accurate data was collected on Arapahoe Unit 4. Results indicate that the FFDC is very effective at the removal of trace-metals, averaging 97.1%. This high removal rate is possible as many of the trace-metals are associated with the particulate and FFDCs are very effective at minimizing particulate emissions.

The release of acid-forming anion emissions was also low, due to the low content of these anions in the coal used on this unit. Emissions of polycyclic aromatic hydrocarbons (PAHs) and radionuclides were very low. None of the carcinogenic PAH compounds were measured above the detection limit.

3 SELECTIVE NONCATALYTIC REDUCTION

This section describes the technology used by the SNCR system to reduce NO_x emissions and the SNCR system at Arapahoe Unit 4. It also describes the objectives, methodology, and results of the SNCR test program. For more information on the technology, design, or process flow of the SNCR system, refer to *Final Report, Volume 1: Public Design.*

3.1 Description of SNCR Technology

SNCR is a class of processes designed to reduce NO_x emissions from fossil-fuel combustion systems. SNCR processes involve the injection of a nitrogen-containing chemical (usually urea or ammonia) into the combustion products at a point where the temperature is between 1,600 and 2,100°F. In this temperature range and in the presence of oxygen (O_2), the SNCR chemical reacts selectively with NO to form N_2 and H_2O. At too high a temperature, the injected chemical reacts directly with the O_2 to form more NO_x. At too low a temperature, the injected chemical does not react with the NO, resulting in excessive emissions of ammonia (NH_3).

The performance of an SNCR system depends greatly on a unit's furnace geometry, fuel, and other factors. Coal-fired units retrofitted with SNCR systems have achieved NO_x reductions ranging from below 20% to above 80%. While maintaining acceptable levels of reagent consumption and ammonia slip, SNCR systems generally achieve NO_x reductions of 30 to 50%. Retrofitting SNCR systems to large utility units where the proper temperature for SNCR occurs in the convection pass cavities, however, is more challenging and may limit NO_x reductions to 20 to 40%.

3.1.1 NO_x Reduction Chemistry of SNCR

Generally, a liquid solution of urea or ammonia (aqueous ammonia) is injected through atomizers into the boiler. The atomizing medium can be either air, steam, or mechanical. The urea and any additives are stored as a liquid and pumped through the injection atomizers. At Arapahoe Unit 4, a system has also been installed to catalytically convert the urea solution to aqueous ammonium compounds for low-load conditions.

When injected into the boiler, all of the water in the diluted urea evaporates before the urea can react with NO. Conversely, ammonia vaporizes directly from aqueous ammonia and begins the NO_x reduction reaction as soon as it is injected. This difference in the method of reacting with NO_x affects the desired injection location. The ammonia/NO_x chemical reaction is very complicated and not well understood but the following equation (Eqn. 3-1) describes the overall reaction of urea, $(NH_2)_2CO$, with NO:

$$(NH_2)_2CO+2NO+\frac{1}{2}O_2 \rightarrow 2N_2+CO_2+2H_2O \qquad \text{(Eqn. 3-1)}$$

3.1.2 Design Concerns

The narrow temperature window in which the SNCR processes are effective is the primary challenge in the design of SNCR injection technology. When the boiler load is changed, the flue-gas temperature for a particular injection location also changes. For this reason, multiple levels of injection are usually required to provide good NO_x removal over a range of boiler load conditions. In addition, the basic temperature and velocity flow patterns of the flue-gas must be defined before a detailed design of an SNCR system can be completed.

If the SNCR-temperature window is located before the convective pass, retrofitting an SNCR system can be fairly straightforward. If the SNCR-temperature window is located in the convective pass, as in many pulverized coal boilers, the retrofit can be much more complex. In this section of the boiler, residence times are much shorter and boiler tubes may block the placement of injectors.

The temperature and flow patterns in the boiler also affect the mixing of the reagent and the flue gas. The existence of recirculating zones may cause poor mixing. Also, the larger the boiler, the more difficult it is to achieve good mixing. SNCR systems are generally classified as low- or high-energy systems. Low-energy systems use mechanical or dual-fluid injectors, inject small amounts of atomizing air, and rely mostly on the flow patterns of the flue gas to mix the reagent and flue-gas. High-energy systems use dual-fluid injectors, inject large amounts of atomizing air at up to sonic velocities, and do not rely as much on boiler flow patterns for mixing. High-energy systems have higher capital and operating costs than low-energy systems. Load following and larger boilers require adequate control systems to adjust for movement of the SNCR-temperature window and to ensure good mixing.

3.2 SNCR System at Arapahoe Unit 4

The SNCR injection system (designed by NOELL, Inc.) is designed to mix the flue gases and the reducing agent to a high degree and in a short residence time. The system can be divided into the four following subsystems:

- Urea-recirculation loop: Stores and heats the base urea solution.
- Injection: Diverts a small slipstream of urea from the recirculation loop, filters it, dilutes it with softened water, and pumps it at high pressure (100 to 1,000 psig) to the atomizers.
- Ammonia conversion: converts urea into ammonia compounds for injection during low-load conditions.
- Atomization: atomizes and distributes the urea or ammonia compounds evenly in the boiler.

Figure 3-1 shows a simplified P&ID of the SNCR system at Arapahoe Unit 4.

3.2.1 Urea Recirculation

The urea-recirculation loop stores and heats the base urea solution. Urea is received as a 65 wt% aqueous solution and is stored in one of two 20,000-gal tanks. To prevent the 65 wt% urea from crystallizing, it must be stored above 115°F. During the baseline testing of the SNCR system, it was found that maintaining a 65 wt% solution of urea above 115°F caused ammonia to vaporize so that a slight odor could be detected on some days. To eliminate the need to heat the solution to 115°F, the urea is diluted to 37.5 wt% urea after delivery. A recirculation pump continuously circulates the solution. The recirculation lines are insulated and include electric in-line heaters.

3.2.2 Injection System

This section briefly describes the lances originally installed and described in *Volume 1*. It then updates *Volume 1* by describing the lances subsequently installed to improve NO_x reduction.

3.2.2.1 Original Injection Lances

Originally, the SNCR system at Arapahoe Unit 4 used 2 rows of 10 wall-mounted injectors, one immediately downstream (level-1) and one immediately upstream (level-2) of the second set of screen tubes. Figure 3-2 shows the original location of the SNCR injectors.

The level-1 tubes are directed 45° down from horizontal so that they inject directly counter to the flow of the flue gas. The level-2 injectors pointed 15° above horizontal. The original design planned for the use of the level-2 injectors during high unit load operation and the level-1 injectors during low unit load operation. During initial testing it was discovered that the level-2 injectors were located in an area of the boiler where the flue-gas temperatures were too cold or the residence time was too short to remove NO_x effectively even at full load. Testing of the level-2 injectors was stopped and all further testing was conducted on the level-1 injectors.

3.2.2.2 Injection Lances Installed Since Issuing Final Report, Volume 1

Because the furnace exit gas temperatures decreased by 170-200°F following the LNB retrofit, the original injection lances were in a location where the temperatures were too low for low load operation.

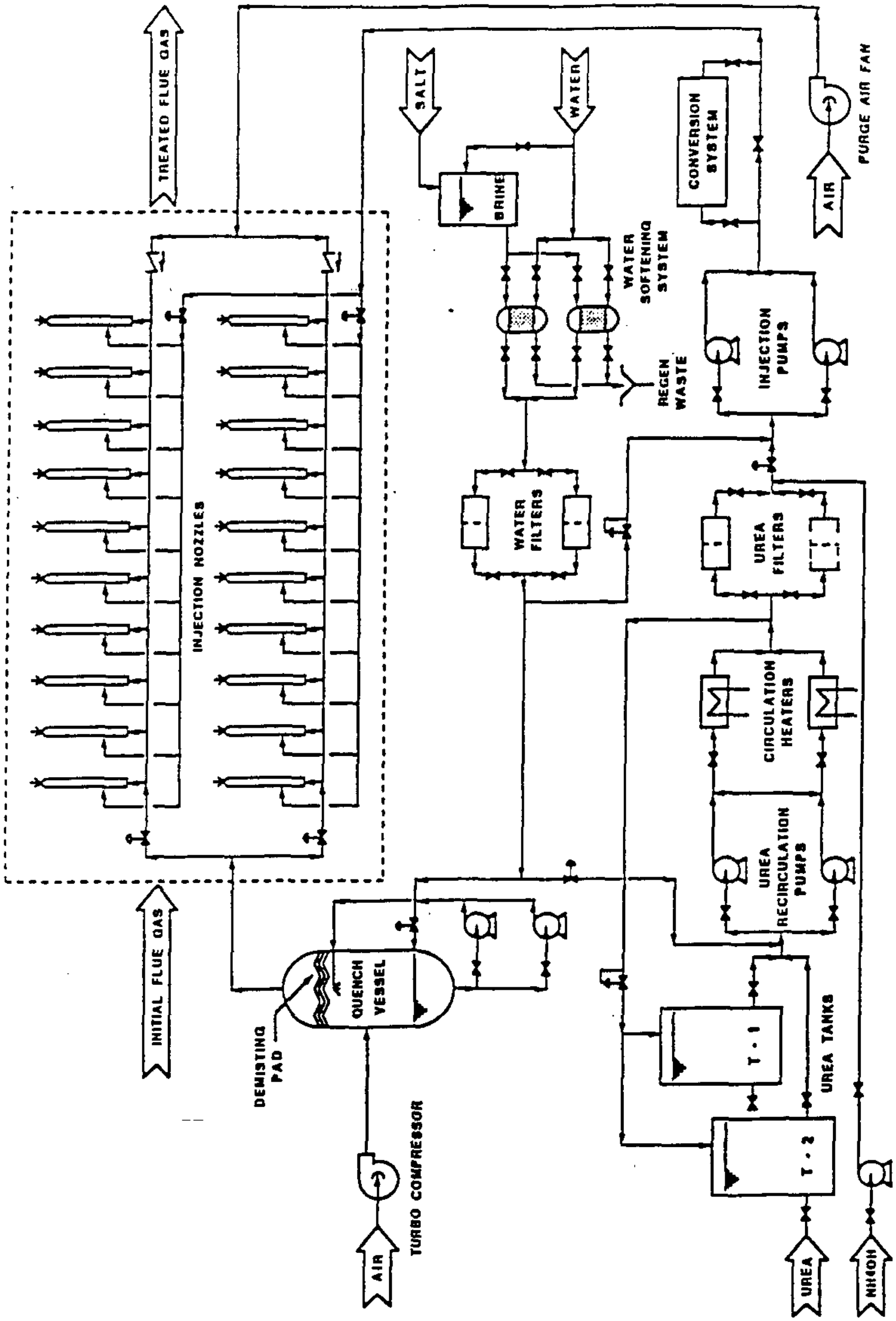


Figure 3-1. P&ID of the SNCR System at Arapahoe Unit 4

NOELL, Inc. (the original supplier of the SNCR system) suggested an additional injection location in a higher temperature region of the furnace. Because no unit outages were planned, the only option for incorporating an additional injection level was to utilize two existing (but unused) sootblower ports in conjunction with NOELL's Advanced Retractable Injection Lances (ARILs). This location was chosen because the ports existed, not because the temperatures were ideal for SNCR. However, a test was completed with a temporary injector to verify the location was appropriate before proceeding with the system design.

Figure 3-2 shows the location of the new ARIL lances relative to the two original SNCR injection locations. Level-2 is the location that became unusable as a result of the flue gas temperature decrease after the low-NO_x combustion system retrofit. The ARIL system consists of two retractable lances and two retractable lance drive mechanisms. Each lance is nominally 4 inches in diameter and approximately 20 feet in length. Each lance has a single row of nine injection nozzles spaced on two-foot centers. A single division wall separates the Arapahoe Unit 4 furnace into east and west halves, each with a width of approximately 20 feet. When each lance is inserted, the first and last nozzles are nominally one foot away from the division and outside walls, respectively. Each injection nozzle is composed of a fixed air orifice (nominally one-inch in diameter), and a replaceable liquid orifice. The liquid orifices are designed for easy removal and cleaning. This ability to change nozzles also allows adjustments in the chemical injection pattern along the length of the lance in order to compensate for any significant maldistributions of flue gas velocity, temperature, or baseline NO_x concentration. Figure 3-3 shows a photo of one of the two lances spray water with the lance retracted from the furnance.

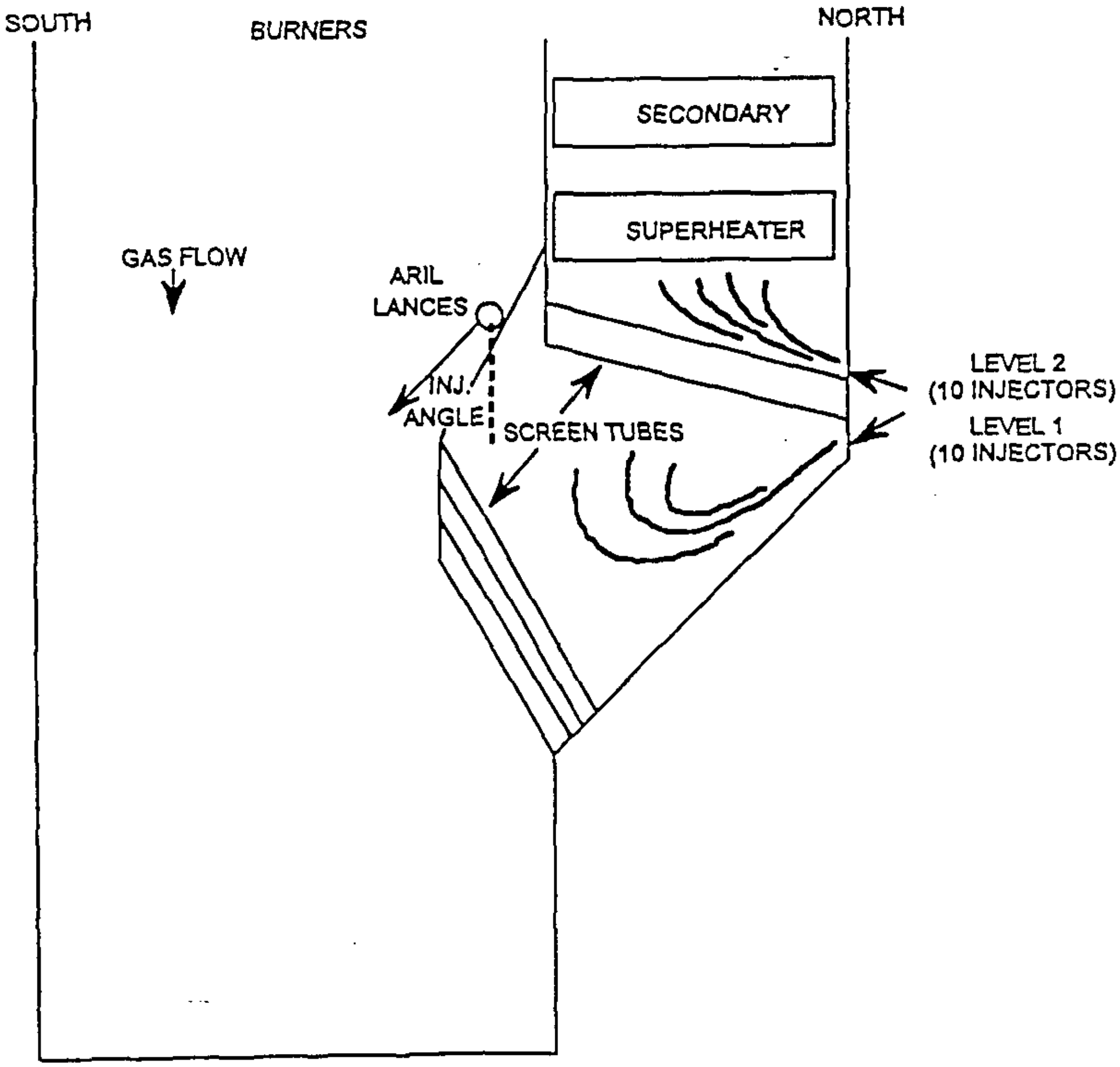


Figure 3-2. Original SNCR Injection Nozzle Location at Arapahoe Unit 4

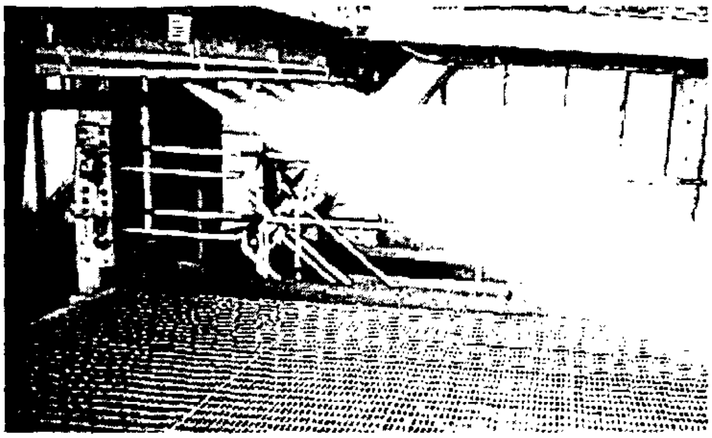


Figure 3-3. SNCR ARIL Lance Spray Water at Arapahoe Unit 4

Two separate internal liquid piping circuits are used to direct the chemical to the individual injection nozzles in each lance. The four nozzles near the tip of the lance are supplied by one circuit, and the remaining five are supplied by the other. This provides the ability to bias the chemical flow between the "inside" and "outside" halves of each side of the furnace in order to compensate for various coal mill out of service patterns. Each lance is also supplied with a pair of internal thermocouples for detecting inside metal temperatures at the tip of the lance.

The retractable lance drive mechanisms were supplied by Diamond Power Specialty Co. (DPSC). The drives are Model IK 525's which have been modified for the liquid and air supply parts. Both remote (automatic) and/or local (manual) insertion and retraction operations are accomplished with the standard IK electric motor and gearbox drive system. A local control panel is provided on each ARIL lance drive mechanism. Each panel contains a programmable logic controller for the lance install/retract sequencing and safety interlocks. Each lance can be rotated either manually at the panel, or automatically by the control system during load-following operation. One of the key features of the ARIL lance system is its ability to rotate the lances. As will be discussed, this feature provides a high degree of flexibility in optimizing SNCR performance by varying the flue gas temperature at the injection location by simply rotating the lance.

The NOELL lances were made of a high alloy material and were designed for the high temperatures in the furnace. However, after approximately 1 month of operation in this high temperature environment, the lances began to have a permanent bow and become difficult to insert and retract from the boiler. It was believed that the large temperature difference between the top and bottom of the lance caused this bow due to a difference in the thermal expansion of the metal. A view of the bent lance is shown in Figure 3-4.

Figure 3-4. SNCR ARIL Bowed Lance

Metallurgy showed no permanent creep damage so the lances were straighten and then coated with a ceramic material to lower the radiation heat transfer to the lance. The ceramic coating provided a marginal improvement but due to continued temporary bending while the lances were inserted in the furnace, the coating began to crack. It was not believed that this lance design would be suitable for long term operation.

A second lance design, supplied by DPSC, was also evaluated. This alternate lance design represented a simplification to the original ARIL design. The liquid solution is injected through a single pressure atomizer located in the air supply pipe ahead of the lance. This eliminates the internal liquid piping, and spraying at the lance inlet provides evaporative cooling to help cool the lance and prevent the bending. The DPSC lance design also eliminated a telescopic device used in the ARIL lance design. The telescope worked well, but contains seals that require replacement due to normal abrasion that occurs during the insert and retract process. In addition, the design prevents air and liquid from being injected in the local region around the boiler when the lances are retracted. The DPSC designed lance provided less control and balancing of the urea solution.

3.2.3 Ammonia Converter

The ammonia converter was added after the SNCR tests performed with the original burners found that the injection of urea through neither level of injectors removed NO_x very effectively at low-load levels. A short test showed that aqueous ammonia reacted more quickly, at a lower temperature in the boiler, and was utilized more effectively than urea. Although ammonia is more effective, for safety reasons it is more desirable to store urea than ammonia. To solve this problem, an on-line conversion system that converts urea into ammonia compounds was installed. This system first heats the urea and then passes it over a proprietary catalyst to convert it to ammonia-based compounds. By bypassing the ammonia conversion system, the operator may select either urea or ammonia injection.

3.2.4 Atomization

The SNCR system at Arapahoe Unit 4 uses NOELL, Inc.'s proprietary dual-fluid injection nozzles to evenly distribute the urea or ammonia compounds into the boiler. A centrifugal compressor supplies a large volume (up to 9,000 scfm) of medium pressure (4 to 12 psig) air to the injection nozzles. The air helps atomize the injected solution to mix rapidly with the flue gas. To ensure proper atomization of the urea solution, the designed system can inject the atomization air at velocities up to the speed of sound.

3.3 SNCR Test Program Objectives

The purpose of the SNCR system at Arapahoe was two-fold. First, to further reduce the final NO_x emissions obtained with the combustion modification so that the goal of 70%

NO_x removal could be achieved. Second, the SNCR system is an important part of the integrated system interacting synergistically with the DSI.

Key SNCR system variables that were part of the current demonstration program include:

- Combustion System
  - Baseline
  - Low NO_x combustion system
- Boiler Operation
  - Load
  - Burner firing configuration (O2, mill pattern)
- SNCR Injection
  - Injection location (level 1, lances, lance angle)
  - Reagent type, (urea, ammonia, converted urea)
  - Injection variables, airflow, orifice size, dilution water flow
  - N/NO ratio
- Key Measurements
  - NOx levels (with and without urea or ammonia)
  - NH3 slip levels
  - CO/N2O levels
  - Ash chemistry

Details of the SNCR test results are documented in Smith, et al, 1993, (Baseline SNCR Report); Smith, et al, 1994 (Low NO_x Combustion System/SNCR Report); Smith, et al., 1996, (ARIL Lance Report).

3.4 SNCR Test Program Methodology

The majority of the SNCR tests were parametric tests which systematically varied the key parameters listed previously. These parametric tests were used to define SNCR operating conditions to be used for automatic control of the system over the load range. Specifically, the parametric tests sought to define the SNCR operating conditions that would maximize NO_x reduction while maintaining NH_3 slip less than 10 ppm.

Once the parameters for automatic operation were defined, long term tests were conducted with the system in a load following mode.

3.4.1 Instrumentation

Additional instrumentation utilized for SNCR testing include manual wet chemical NH_3 sampling and the use of a multipoint gas analyzer to aid in rapidly tuning the SNCR injection parameters.

3.4.1.1 NH_3 Measurements

Wet chemical NH_3 analysis was the primary measurement used during the SNCR parametric test program. Flue gas samples were withdrawn from the duct through a stainless steel probe, and passed through three impingers as shown in Figure 3-5. The first two impingers contained 0.02N sulfuric acid (H_2SO_4) and the final impinger was dry. Nominally two cubic feet of flue-gas was passed through the impinger train at a rate of approximately 0.2 ft^3/min. Total sample times were 10 to 12 minutes for each test. At the conclusion of each test, the sample probe, Teflon line, and sampling train glassware were washed with dilute H_2SO_4 into the bottle containing the impinger solution. The sample solution was analyzed for NH_3 concentration.

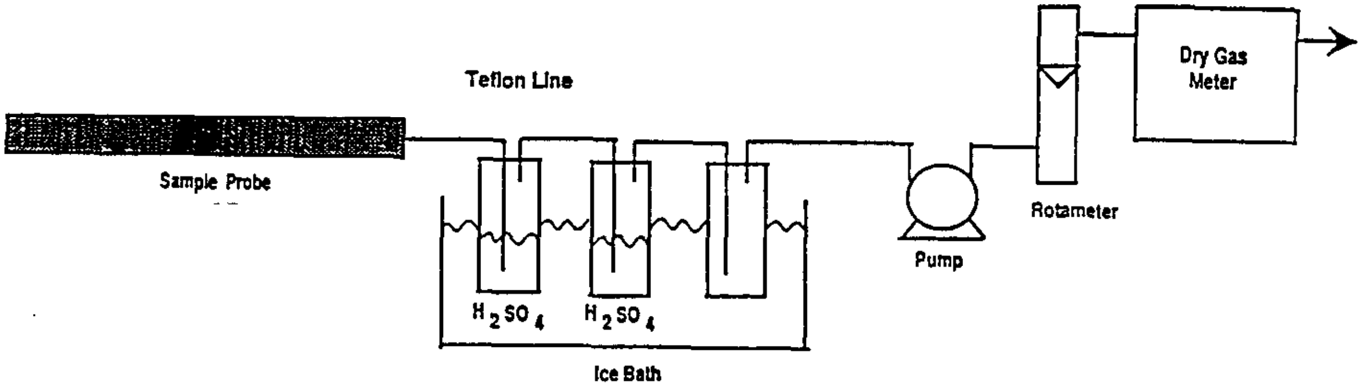


Figure 3-5. NH_3 Sample Train Schematic

During the baseline SNCR tests, the sample solutions were analyzed with a specific ion electrode, which is a standard analysis technique. In order to provide a more rapid turn around during later tests, the sample solutions were analyzed on-site using the Direct Nesslerization Method. The Nesslerization Method is a colorimetric analysis method. In this method, Nessler reagent and a stabilizing agent (EDTA) are added to the sample solution and mixed thoroughly. NH_3 is then determined photometrically using a wavelength of 425 nm. The reading is compared to the absorbency of standard solutions to determine the NH_3 concentration in the sample. Using this method, an NH_3 emission value could be obtained in a manner of minutes after a sample was collected.

The majority of the wet chemical NH_3 samples were obtained from a set of six ports located in the air heater exit duct (just downstream of the port used for CEM). A limited number of samples were obtained downstream of the fabric filter.

3.4.1.2 Multipoint Gas Analyzer

Optimizing the SNCR process entails obtaining a uniform distribution of chemical at the plane of injection. The uniformity can be assessed by obtaining gas samples from the individual twelve probes at the economizer exit. Using the normal gas analyzers, this process is time-consuming requiring 1 to 2 hours. To speed up this process, a multipoint gas analyzer developed by FERCo, was used for a portion of the SNCR test program. This analyzer simultaneously analyzes up to 12 individual samples for NO, CO and O_2, and displays the result as a real time contour plot on a computer screen. This allows the extent of mixing to be rapidly determined along with assessing the impact of changes to the SNCR parameters on mixing.

3.4.2 Test Methods

Parametric testing was performed by carefully controlling the various SNCR and boiler variables in a systematic manner, to determine their effect on system operation, NO_x removal and NH_3 slip. Key system variable include:

- Boiler load
- SNCR injection location (Level 1, Level 2, retractable lances)
- Sorbent injection rate (2Na/S ratio: 0-2.5)
- SNCR injection chemical (urea, converted urea, NH_4OH)
- SNCR injection rate (N/NO ratio: 0-3)
- Coal type

For the parametric tests, the system was allowed to stabilize at the desired test conditions to insure steady state operation. During the test period, documenting system operation was performed by completing boiler control room, sorbent injection and humidification data sheets from the DCS control screens as well as composite gas emissions at the economizer exit and single point CEM measurements, including NH_3 slip at the air preheater exit, and composite wet chemical NH_3 slip measurements at the air preheater exit. Additional test data obtained for specific tests could include:

- Detailed point-by-point gaseous measurements at the economizer exit.
- Detailed wet chemical NH_3 measurements at the air preheater exit.
- CEM NH_3 measurements at the FFDC exit.
- FFDC hopper ash samples for analysis of absorbed NH_3.

Following completion of a single test, additional adjustments to the SNCR system were performed and the process repeated. The parametric tests of the SNCR system were performed to define the operating conditions for long-term automatic operation.

The long-term tests were conducted with the system operating in an automatic control mode. Data was logged by the DCS and the CEM system.

3.4.3 Quality Control/Quality Assurance

3.4.3.1 NH_3 Analysis

The rapid turnaround of NH_3 emission data was used to quickly diagnose and guide the test program during the optimization of the SNCR injection system. However, a portion of each sample solution was also later analyzed off-site with a specific ion electrode, since this analysis was considered to be more precise. Figure 3-6 compares the NH_3 values from the two methods. The results show a reasonable correlation between the two, but a significant amount of scatter is also apparent.

During an early test at 60 MWe, it was found that the NH_3 emission results were not responding as expected to changes in the N/NO ratio and there was poor repeatability in the NH_3 slip measurements. At 60 MWe, flue gas temperatures were low enough to allow adsorption and desorption of NH_3 by fly ash deposits in the duct. After making a change to an SNCR parameter at 60 MWe, it was necessary to wait nominally one hour for the system to stabilize. At boiler loads above 60 MWe, waiting 15 to 20 minutes after starting a test (i.e., changing an injection parameter) before acquiring the NH_3 sample was more than sufficient to assure consistent and repeatable results. However, all subsequent tests at 60 MWe were run with a minimum waiting period of one hour, in order to allow the air heater exit NH_3 emissions to stabilize. No further repeatability problems with the wet chemical technique were encountered after the adoption of this test protocol.

Although the wet chemical technique was the primary measurement method for NH_3 during the current test program, the CEM NH_3 measurements at the air heater exit and stack sampling points were also recorded. Figure 3-7 compares the continuous NH_3 measurements at the air heater exit location to wet chemical NH_3 measurements at the port closest to the CEM probe.

The results show good agreement between the two methods. However, wet NH_3 chemical traverses across the air heater exit duct showed that the NH_3 concentration was highly stratified. Therefore, the single CEM probe at the air heater exit could not be used to accurately characterize the NH_3 slip.

In order to check for accuracy of the CEM NH_3 measurements at the stack, a limited number of wet chemical NH_3 samples were also collected. The results (Figure 3-8) show good agreement between the two methods. If the high slip point is removed from the data set, the correspondence between the two methods is nearly one-to-one.

Overall, the CEM NH_3 measurement was quite good. However, at the air heater exit location it could never be used as an absolute measurement, due to the stratification of the flue gas at this location. At the stack location, the CEM was accurate enough to provide a valid indication of NH_3 slip.

3.5 SNCR Test Program Results

A number of test campaigns were conducted with the SNCR part of the integrated system. Before presenting the results, it is of value to briefly provide a chronology of the tests:

Baseline SNCR Tests

Prior to the low NO_x combustion system retrofit, SNCR tests were conducted with urea as the primary SNCR chemical. Limited tests were also conducted with aqueous NH_3. These tests utilized the two injection levels on the back walls (Levels 1 and 2).

Retrofit Combustion System/SNCR

Following the low NO_x combustion system retrofit, SNCR tests were conducted with urea using the back wall injectors (Levels 1 and 2). As a result of the low NO_x combustion system retrofit, the furnace exit gas temperature decreased by 200°F. This rendered the Level 2 injection location ineffective and limited the capability of the SNCR system at low loads.

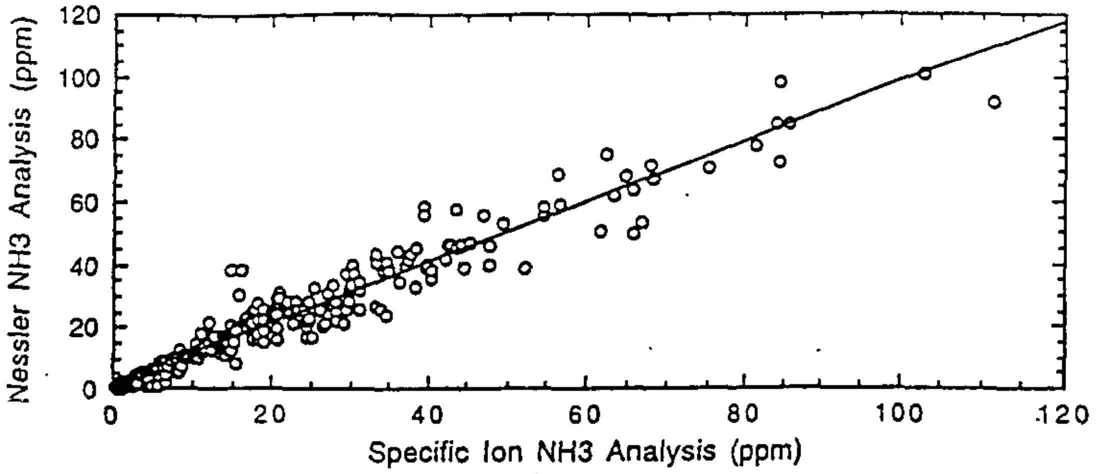


Figure 3-6. Crossplot of Nessler and Specific Ion NH_3 Analyses (ppm)

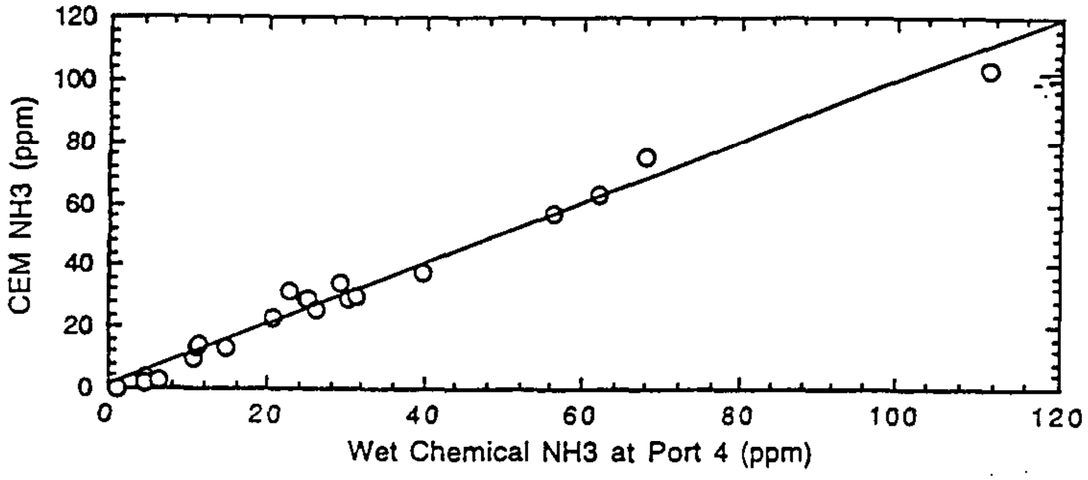


Figure 3-7. Comparison between CEM and Wet Chemical NH_3 Analyses at Air Heater Exit

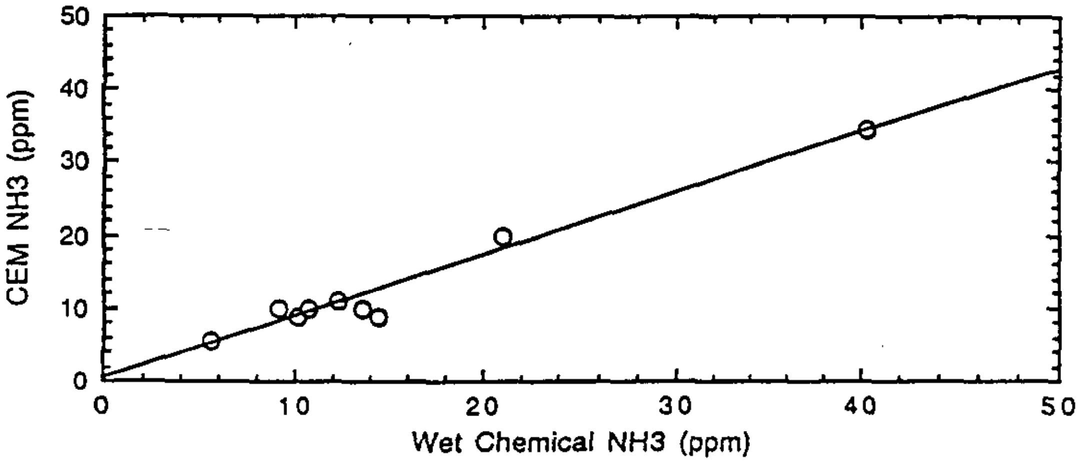


Figure 3-8. Comparison between CEM and Wet Chemical Analyses at Stack

Converted Urea

During the baseline tests, it was shown that aqueous NH_3 was more effective than urea at lower temperatures. To extend the low load performance of the SNCR system, a system was installed that catalytically converted the aqueous urea to a mixture of aqueous NH_3 compounds prior to injection in the furnace. SNCR parametric tests conducted with this converter system showed some improvement at low loads.

ARIL Lances

To further improve the low load performance, a pair of retractable and rotatable lances were installed through two unused sootblower ports on the east and west sides of the furnace. These lances supplied by NOELL, Inc., are referred to as ARIL lances. SNCR tests with the ARIL lances markedly improved low load performance.

DPSC Lances

An alternate lance design supplied by Diamond Power Specialty Company (DPSC) was also tested. This lance design overcame some inherent mechanical shortcomings of the ARIL design.

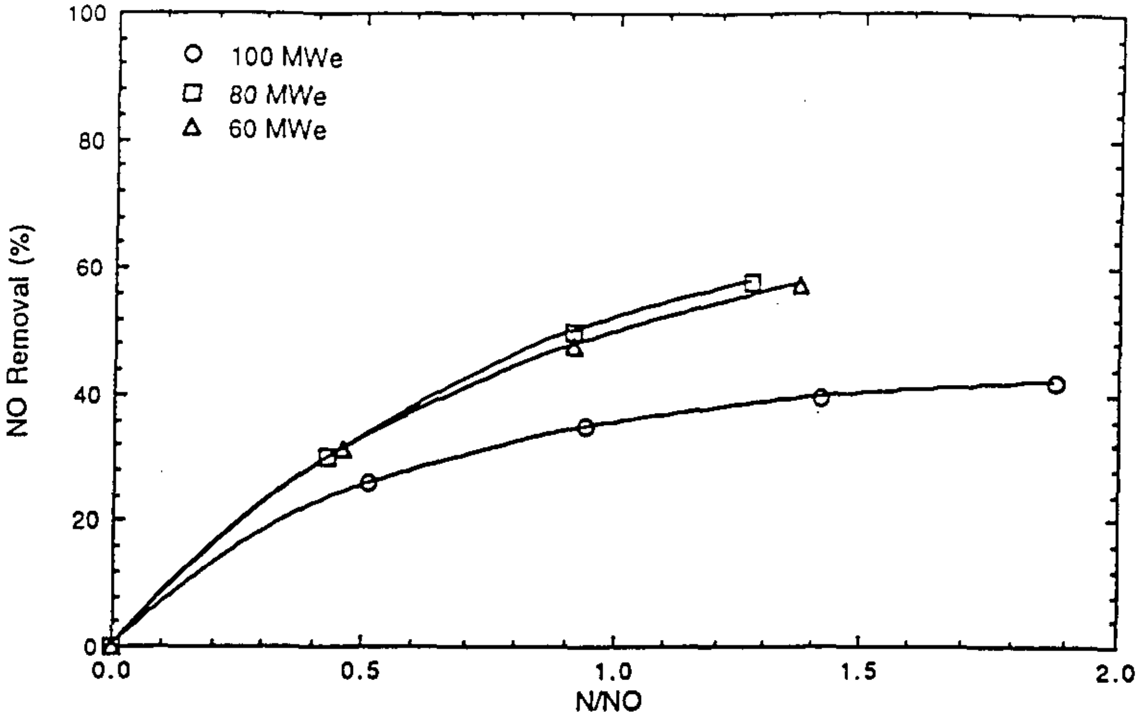
The results of these various test phases will be presented below. Also note that all of the test phases listed above, with the exception of the results of the DPSC lance tests have been reported in detail in other project reports.

3.5.1 Baseline SNCR

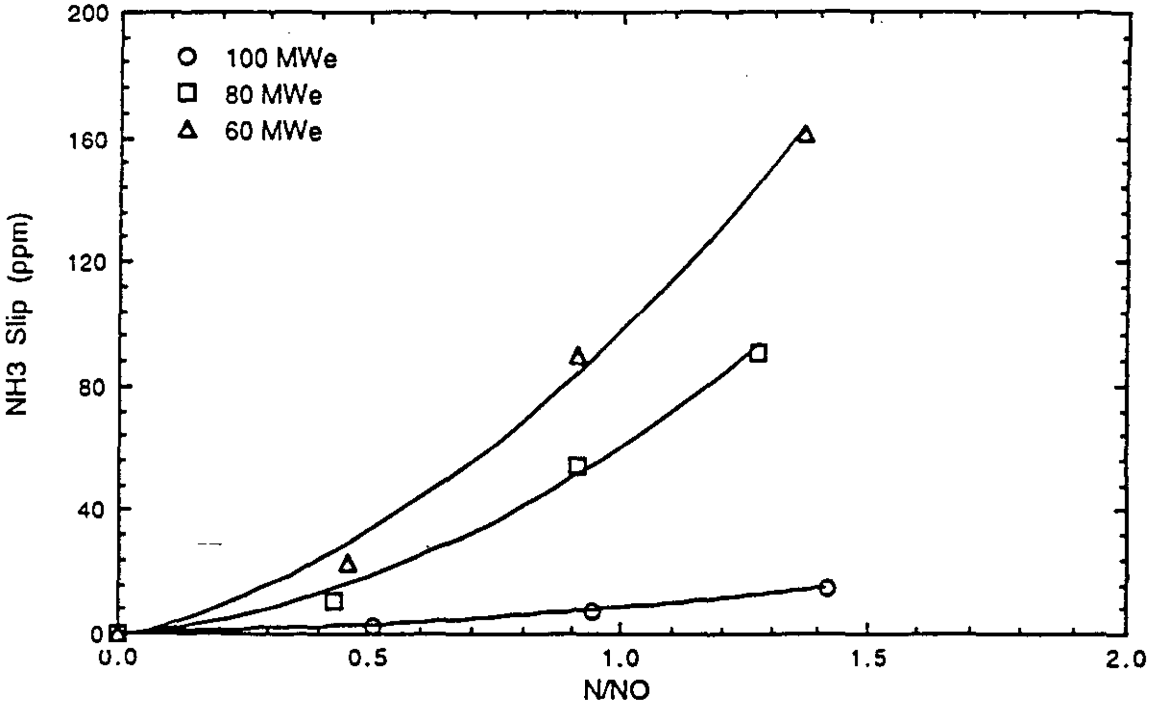
This subsection describes the SNCR tests with the original combustion system, with initial NO_x levels of 800 - 900 ppm.

3.5.1.1 Urea

The effect of urea injection rate on NO removal and NH_3 slip is shown in Figures 3-9(a) and 3-9(b), respectively, for boiler loads of 100, 80 and 60 MWe using the Level 1 injection location. For all three loads, the NO removal increased as the N/NO ratio was increased. At a nominal N/NO ratio of 1.0, NO removal was 37 percent at full load conditions of 100 MWe; removals improved at a lower load of 80 MWe, then started to decrease as the load was further reduced to 60 MWe. Optimum temperature for this set of injector conditions occured in the load range of 60 to 80 MWe. As the load increased,



(a) NO Removal



(b) NH_3 Emissions

Figure 3-9. Original Combustion System: Effect of Boiler Load on Urea Injection with 7 gpm. Total Liquid Flow (Level 1 Injection: 8 psig Air) flue gas temperatures increased and NO removal was reduced. This indicates that 100 MWe was on the high side of the temperature window for urea injection.

The NH_3 slip data confirm that 100 MWe was on the high side of the temperature window as the low NO removals are accompanied by low NH_3 emissions (Figure 3-9(b). At 100 MWe, the NH_3 emissions were less than 10 ppm at a nominal N/NO ratio of 1.0; increasing to about 60 and 97 ppm at 80 and 60 MWe, respectively.

The amount of dilution water flow can be used to optimize the urea injection performance. Parametric variations in total liquid flow rate were made over the range of 7 to 28 gpm at loads of 60, 80 and 100 MWe. The NO removal and NH_3 emission results for this series of tests are shown in Figure 3-10 for a high boiler load. At 100 MWe, increasing the total liquid injection flow rate from 7 to 28 gpm increased the level of NO reduction as well as NH_3 emissions. This again was primarily a temperature effect. At 100 MWe, injection was on the high temperature side of the SNCR temperature window. Increased water flow provides local cooling, moving the temperature to a more optimum point in the SNCR temperature window.

In addition to the localized cooling effect, the additional liquid could also alter the drop size of the spray and extend the evaporation times. This would allow the drops to be carried to a cooler region before the reactive nitrogen species are released from the aqueous phase to react with the NO. Thus, at a boiler load of 100 MWe, some control of the performance of the urea injection system can be achieved by varying the amount of dilution water. From an operational standpoint, using very high liquid flows is not practical due to impact on steam attemperation rates and the ability of the boiler to maintain steam temperatures. There is also a major boiler efficiency impact.

3.5.1.2 Aqueous NH_3

The data presented show that with urea injection at reduced loads, only small NO reductions were possible while maintaining reasonable levels of NH_3 slip. Tests with levels are equal in terms of NH_3 slip normalized by the amount of urea injected, the lower initial NO_x levels lead to lower NH_3 slip levels on a ppm basis.

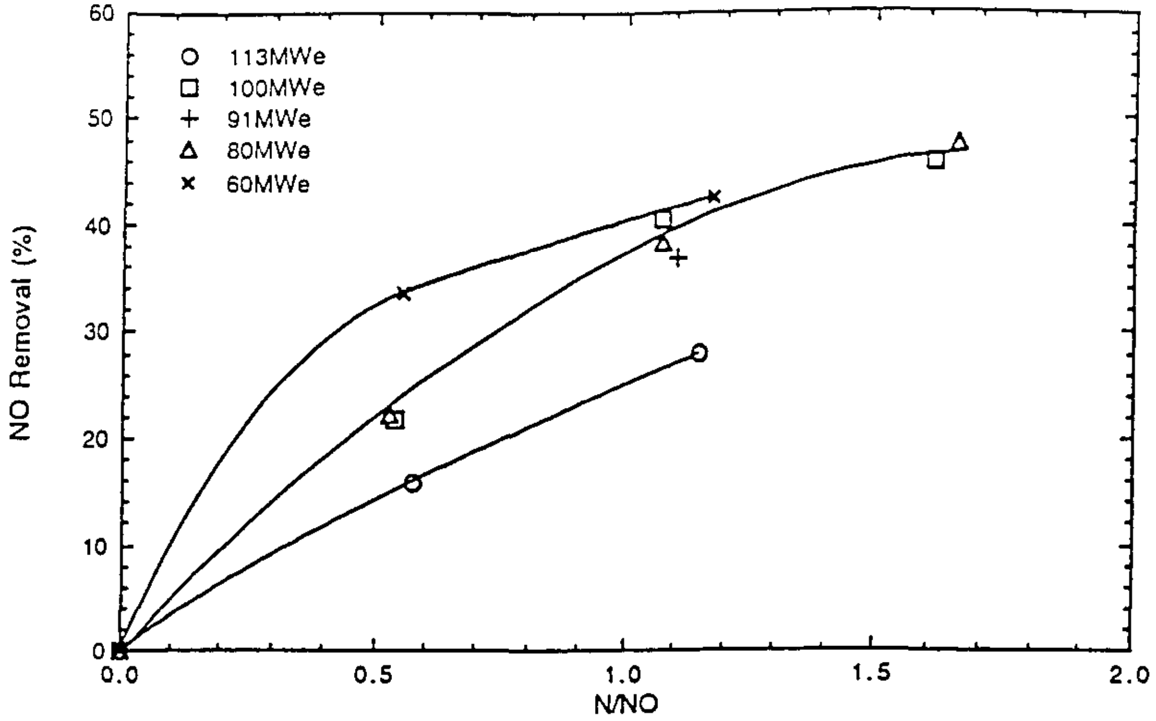
At 60 MWe, urea injection with the original combustion system yielded higher NO removals with a 10 ppm NH_3 slip level. This can be attributed to flue gas temperatures which were closer to the optimal temperature at this load with the original combustion system. At reduced loads of 60 MWe, the SNCR performance with the original burners were aided by the higher gas temperatures, and therefore, resulted in better NO_x removals than with the retrofit low NO_x combustion system.

3.5.2.3 Converted Urea

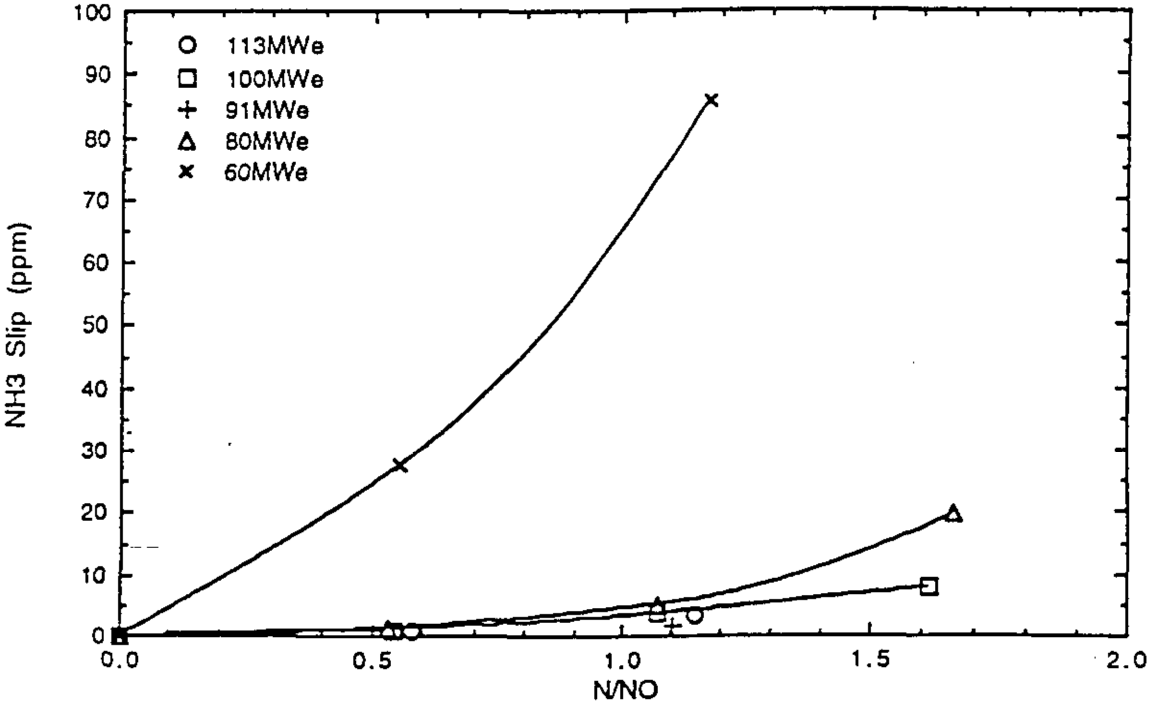
To increase low load performance, the test program investigated the SNCR performance with the urea processed through a catalytic converter prior to injection. The converter catalytically converted the liquid urea solution to a solution of NH_3 compounds which were expected to be more effective at lower temperatures (i.e., similar to the behavior of aqueous NH_3 with the original combustion system).

The effect of boiler load and chemical injection rate (N/NO ratio) is shown in Figure 3-15(a) for operation with the converted urea solution. The same number of mills were used for each load range as for the urea results discussed previously. The results indicate that maximum NO removals occurred at 60 MWe (recall that optimum performance occurred at 100 MWe with urea). There was little difference in the NO reduction performance of the converted urea over the load range from 60 to 100 MWe (with exception of one 60 MWe point at 0.6 N/NO). At 113 MWe, NO removals decreased due to the higher temperatures at the injection location.

The NH_3 emissions shown in Figure 3-15(b) indicate generally low levels of NH_3 with the converted urea solution. Except for the 60 MWe tests, NH_3 emissions were less than 20 ppm even at N/NO ratios approaching 1.7. As with the urea injection results, the higher NH_3 slip levels at 60 MWe were due to both lower flue gas temperatures at the injection location, and boiler operation with only three mills in service.



(a) NO Removal



(b) NH_3 Emissions

Figure 3-15. Retrofit Combustion System: Effect of Boiler Load and N/NO Ratio with Converted Urea Injection (Level 1 Injectors, 8 psig Air

3.5.2.4 Comparison Between Urea and Converted Urea

A comparison of urea and converted urea over the load range is shown in Figure 3-16, for a 10 ppm NH3 slip limit. The numbers in parentheses denote the corresponding N/NO ratio at each load. Over the load range, the converted urea consistently provided higher NO removals while maintaining NH_3 emissions below 10 ppm. However, this increase in NO reduction with the converted urea was attained at the expense of higher N/NO ratios (i.e., lower urea utilization). For instance, at 100 MWe twice as much chemical was needed to achieve a 47 percent NO removal with the converted urea compared to a 43 percent NO removal with urea alone. Long-Term Urea Load Following Evaluation

Following completion of the parametric urea tests with the Level 1 injectors, the boiler was operated for a period of five days (April 5 to 9, 1993) under normal load following conditions. A urea injection schedule was established based on the parametric tests that would limit NH_3 slip to 10 ppm over the load range (Table 3-1). Note that the control system was not designed to maintain a constant N/NO ratio. Rather, a schedule of urea injection rate versus load is input along with a NH_3 slip trim control.

Injection Level:	Level 1
Liquid Orifices:	Injectors 1 through 9, 0.035" dia. Injector 10, 0.024" dia.
Injection Air Pressure:	8 psig

Load (MWe)	Total Liquid Flow Rate (gpm)	Target N/NOs
60	2.0	0.2
80	2.2	0.54
100	6.0	0.75
110	6.0	1.39

Table 3-1. Long-Term Urea Injection Parameters

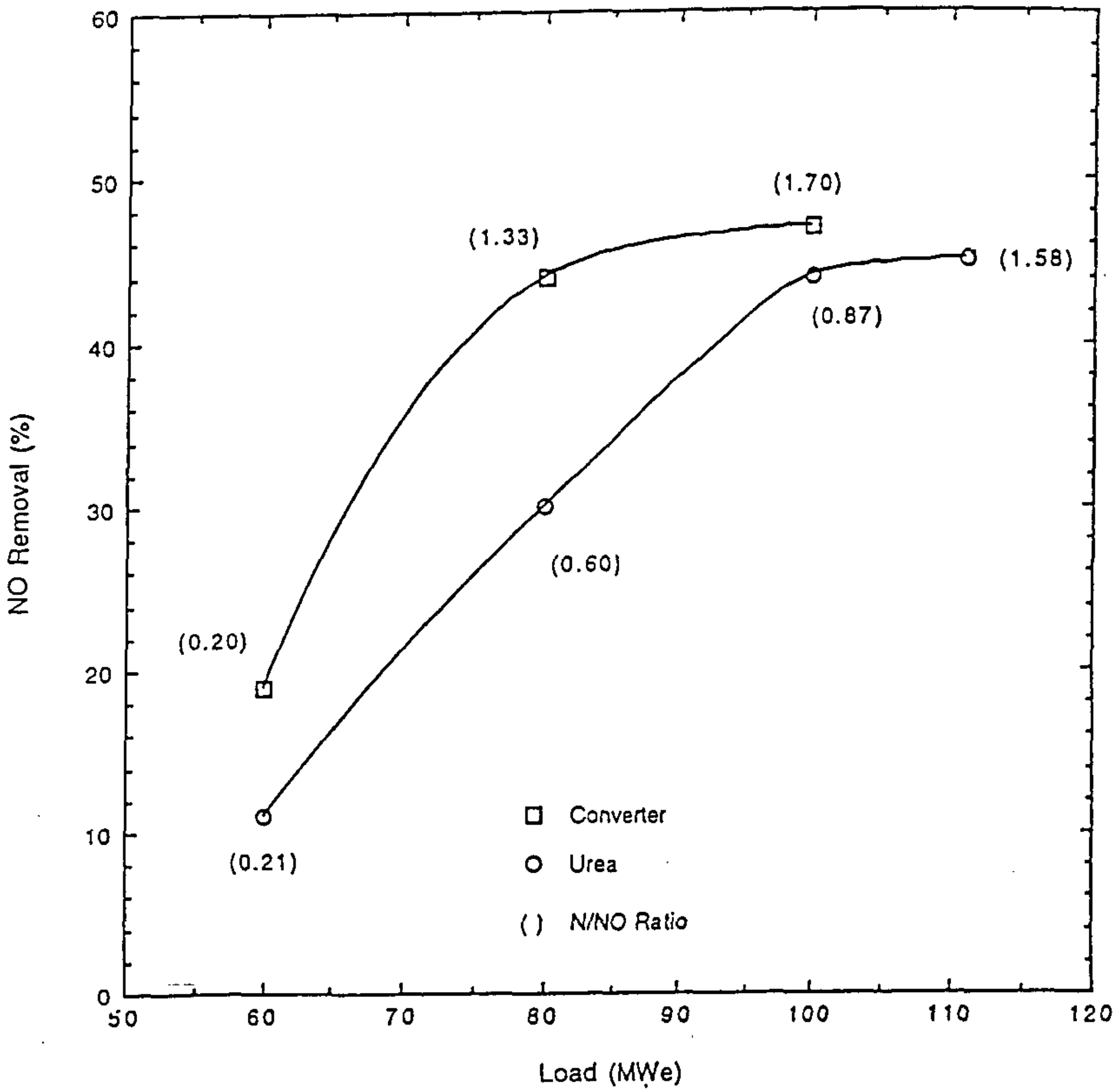


Figure 3-16. Comparison of NO Removals with Urea and Converted Urea for a Fixed NH_3 Slip Level of 10 ppm (Level 1 Injectors)

This test period was intended to assess the potential long-term SNCR performance possible without imposing operational constraints on the boiler. Gaseous emission data were collected automatically with the CEM from the stack location. The SNCR load following tests are compared to the previous long-term data collected with the retrofit low-NO_x combustion system alone in Figure 3-17. Each retrofit burner data point represents an hourly CEM average, while the retrofit burner/urea injection points are based on 10-minute averages. The data show that, with or without urea injection, there was a significant amount of scatter in the outlet NO_x levels across the load range.

The trends with urea injection show lower outlet NO_x level at higher loads, consistent with the higher target N/NO ratios that were designed for these loads. On average, long term, high load NO_x reductions were 35%, while 15 to 20% were achieved at mid-loads. At the lowest loads shown, there were little or no reductions, however, as was shown in Figure 3-16, the expected reduction at low load was only 11 percent.

3.5.3 Urea Lance Results

Retractable urea injection lances were installed to improve the low load SNCR performance. The lances were installed through existing, unused sootblower ports on the side of the unit and provided access to a higher temperature region of the furnace. A key advantage of the lances was the ability to rotate and inject the urea at various locations, in order to obtain optimum temperatures for urea injection over the load range. NOELL, Inc., initially proposed the use of the lances to extend the low load performance of the SNCR system. Their lances, called ARIL lances (Advanced Retractable Injection Lances) were used for the majority of the test program. A second lance design provided by Diamond Power Specialty Company (DPSC) was also evaluated. The DPSC lances were intended to overcome some mechanical design issues associated with the ARIL lance design.

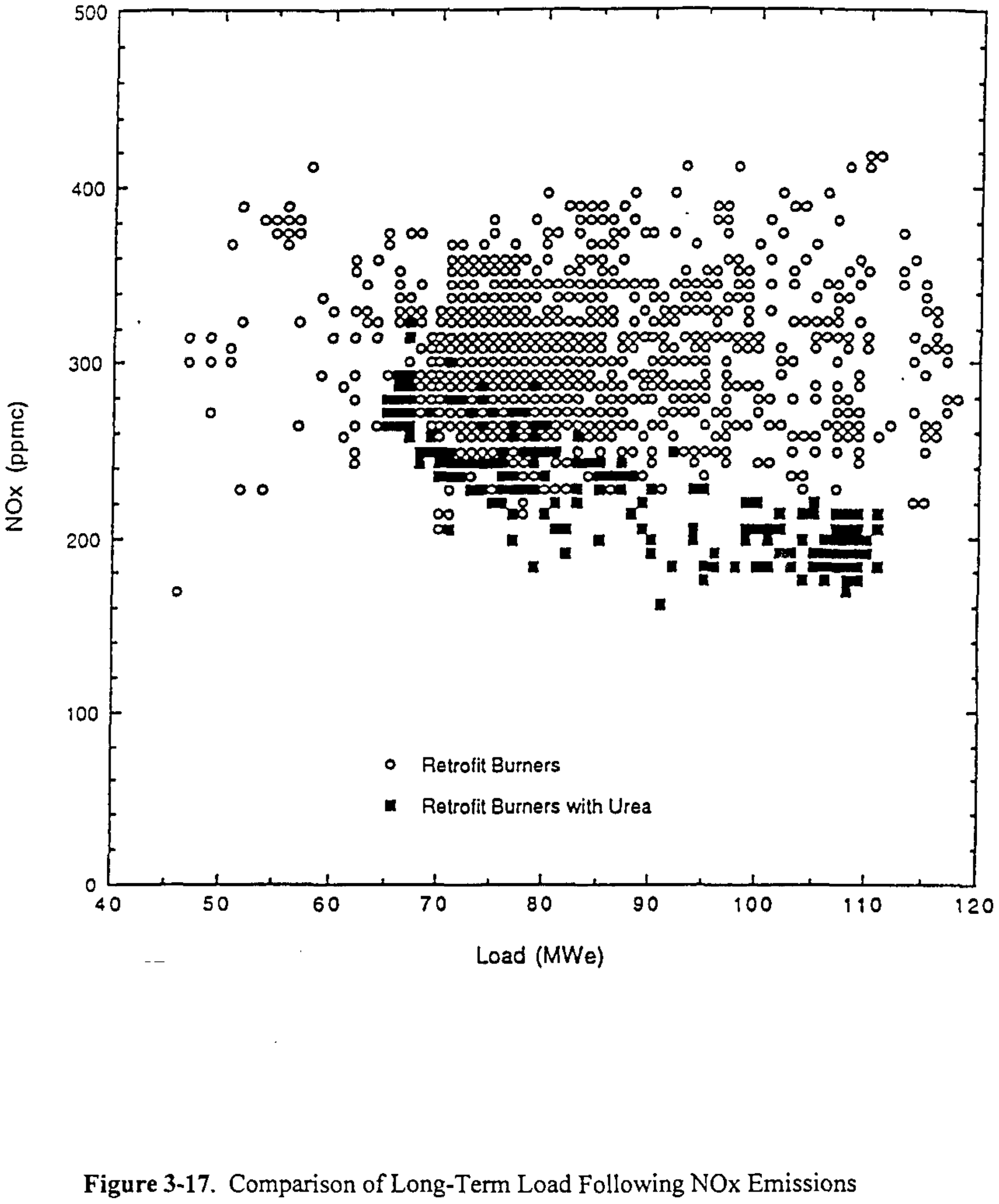


Figure 3-17. Comparison of Long-Term Load Following NOx Emissions with and without Urea Injection (Level 1 Injectors)

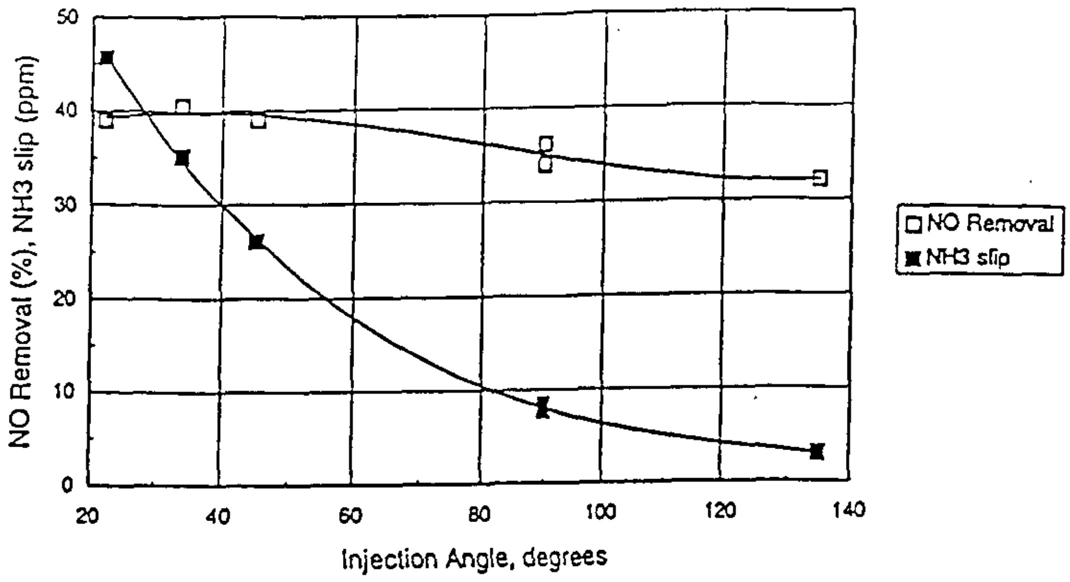
Each lance can rotate to inject urea into a different region of the furnace in order to follow the SNCR temperature window as the boiler load changes. The minimum injection angle is 22° (0° corresponds to injection vertically downward), at which point the chemical is injected parallel to the tube wall located below the lances. Larger lance angles correspond to injecting urea into hotter section of the boiler.

3.5.3.1 ARIL Lance Results

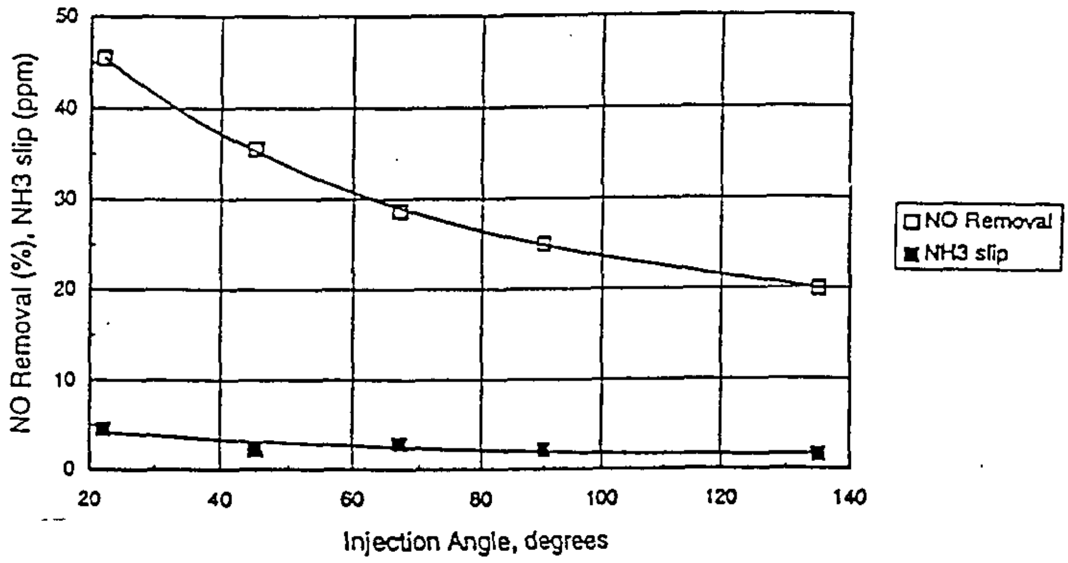
One of the primary attributes of the ARIL lance system is the inherent flexibility of accessing the optimum flue gas temperature location by simply rotating the lance. Figure 3-18 shows the effect of varying the lance injection angle at loads of 43 and 50 MWe. All of the tests shown in these figures were performed at a N/NO ratio of 1.0, with two mills in service. At 43 MWe, varying the injection angle had little effect on NO removal, and the maximum removal occurred at an angle of 35 degrees (Figure 3-18(a)). However, the lance angle had a large effect on NH_3 slip; decreasing from 46 ppm at an angle of 22° to under 5 ppm at an angle of 135°. This overall behavior at 43 MWe suggests that, on average, injection is occurring just on the high side of the SNCR temperature window. Since it is desirable to maintain the NH_3 slip less than 10 ppm, an injection angle of 90° is a more appropriate operating angle at this load.

At a slightly higher load of 50 MWe (Figure 3-18(b)), the effect of lance injection angle was markedly different. At this load, where the average flue gas temperature was higher, injection angle had little effect on NH_3 slip, however, lance angle had a large effect on NO removal. The relative insensitivity of the NH_3 slip and large sensitivity of the NO removal to lance angle suggests that at 50 MWe, chemical injection is occurring far on the high side of the SNCR temperature window for injection angles ranging from 22° to 135°. At this load, a 45° lance angle was considered as an appropriate operating point.

The results at 43 and 50 MWe illustrate how varying lance angle can be used to optimize the SNCR performance over the load range. As the load increases, the preferred injection angle will decrease, which corresponds to lower temperature zones.



(a) 43 MWe



(b) 50 MWe

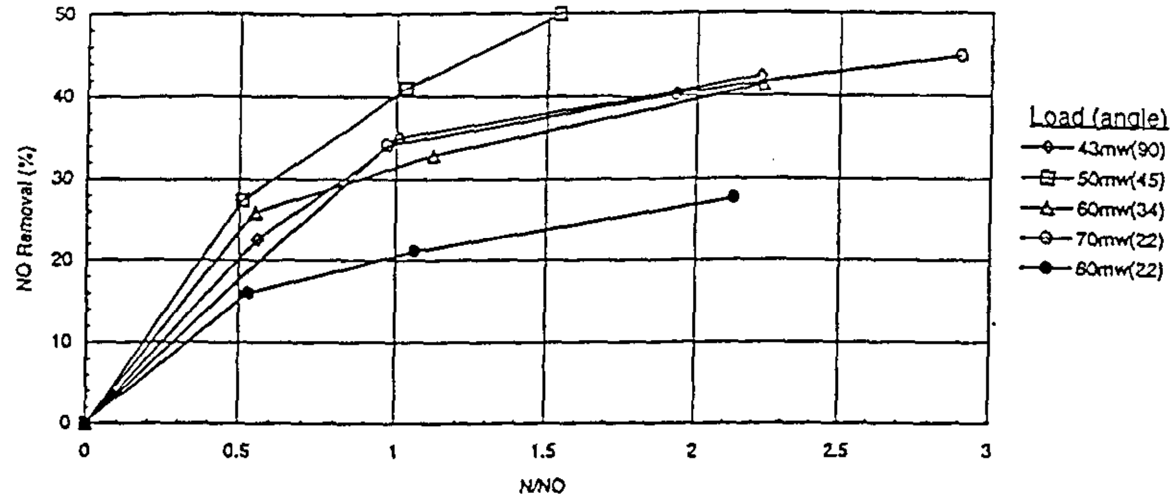
Figure 3-18. Effect of Injection Angle on NO Removal and NH_3 Slip
(Loads: 43 and 50 MWe, N/NO = 1.0)

The SNCR performance using the ARIL lances over the load range from 43 to 80 MWe is shown in Figure 3-19. For this particular lance location, the flue gas temperatures are too high for the lances to be effective above 80 MWe. As the load increases, the preferred lance angle decreases in order to inject the urea into a lower temperature region.

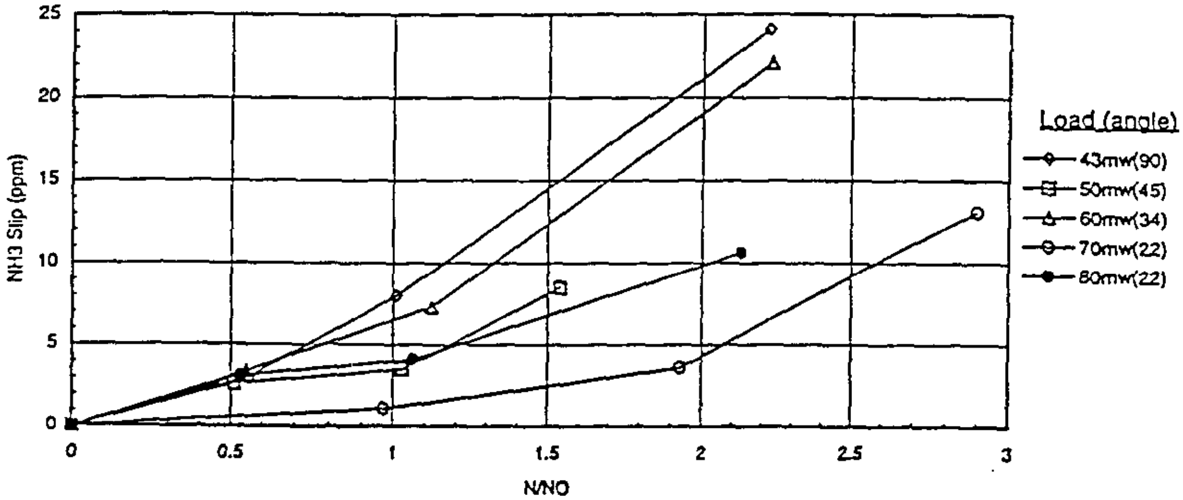
At 43 MWe with an angle of 90°, injection occurred on average just on the high temperature side of the window. At $N/NO_x = 1$, NO_x removals were 35% with less than 10 ppm NH_3 slip. At 50 MWe, a 45° injection angle was on average at a better location in the SNCR window, with NO_x removals of 40% and NH_3 slip less of 5 ppm at $N/NO_x = 1$. As the load increased to 60 MWe, a decrease in lance angle to 34° resulted in SNCR performance similar to a load of 43 MWe. At higher loads of 70 and 80 MWe, injection was clearly occurring on the high side of the temperature window. Comparing the ARIL lance performance with the low load wall injectors, clearly demonstrates the markedly improved low load performance of the SNCR system.

The parametric tests were used to develop settings for automatic control operation of the SNCR with the ARIL lances. These will be presented in Section 3.5.3.2 which compares the performance of the ARIL lances with the alternate DPSC lances. While the process performance of the lances at low load was good, the NOELL ARIL lances experienced some design shortcomings. The air cooling was marginal, resulting in a tendency for the lance to bend. During insertion and retraction, the NOELL design resulted in the atomizing air being injected through the nozzles which were outside the boiler. This creates a potential safety concern to personnel in the vicinity of the lance. Also, the NOELL ARIL lance utilizes a sliding telescopic mechanism between the lance and air supply. The seals of this telescope are subject to wear and accumulation of dirt and ash. This results in some air leakage and problems rotating the lance.

The long term performance of the SNCR system incorporating the ARIL lances is discussed in the section on integrated system performance.



(a) NO Removal



(b) NH_3 Emissions

Figure 3-19. ARIL Lance Performance Over the Load Range: 43 to 80 MWe

3.5.3.2 DPSC Lance Results

DPSC proposed a lance design that represented a simplification of the original ARIL design while at the same time overcoming the shortcomings of the ARIL lance design. Specifically, the atomization of the liquid stream would be accomplished with a single pressure atomized spray nozzle located in the air supply pipe ahead of the lance. Thus, the DPSC lance design had no internal liquid piping. The liquid spray at the lance inlet would provide evaporative cooling when the lance was inserted into the hot flue gas stream, and the chemical would be injected as a vapor. The evaporative cooling effect would supplement the air cooling, helping to reduce bending of the lance.

To assess the merits of the DPSC lance design a single DPSC lance was installed on the west side of Arapahoe Unit 4. This was followed by a two week test program in August of 1996, the results of which are documented in Muzio, et al., 1997. Overall, the DPSC lance performed well mechanically. The lance exhibited less bending and minimized air injection outside of the boiler.

However, the NO_x reduction and NH_3 slip performance were not quite as good as the ARIL lance. This was attributed to a maldistribution of urea along the lance due to the single atomizer at the inlet to the lance. Incomplete evaporation resulted in urea being carried to the end of the lance. In addition, the feed tube geometry of the DPSC lance created an additional pressure drop restricting the amount of cooling air. This resulted in less penetration of the jets; although this was partially compensated by the larger drop size of the unatomized portion carried farther into the furnace before decomposing and releasing reactive nitrogen components.

Overall, the results of the short two week test program were sufficiently positive that a second lance was ordered and installed on the east side of the boiler in November 1996. This section of the final report documents the results of a nominal three to four week test program of the SNCR system using two DPSC lances. This subsection will be somewhat longer than other results sections as this material has not been previously published.

The test program comprised a parametric series of tests at loads of 50, 60 and 70 MWe. These tests were designed to define the optimum lance operating conditions for automatic operation. The parametric test series was followed by a period of automatic operation of the lances. During this automatic operating period, the sodium based dry sorbent injection system was also on line in an automatic mode. This subsection documents the results of the DPSC parametric lance tests. Results of the long term operation with the DPSC lances will be presented in the subsection on integrated system performance.

With both DPSC lances installed, a series of parametric tests were conducted to both characterize the performance of the lances and to define the lance parameters for use during automatic operations. During the test period, the C pulverizer was out of service, so all three mill tests were performed with the C Mill out of service; two mill tests were performed with B and C mills out of service. Table 3-2 outlines the scope of the parametric tests and Appendix A contains the detailed data for this testing.

From prior SNCR tests with both the back wall injectors and ARIL lances, the mill out of service pattern has a major impact on the temperature distribution across the furnace (Smith, et al., 1994 and Muzio, et al., 1997). Ideally, the test program should have included mill pattern as a parameter. Again, this was not possible during the current test period since the C mill was inoperable.

The results of the parametric tests are discussed below for each load.

Load (MWe)	Pulverizer (OOS)	Lance Angle (degree)	Total Liquid Flow (gpm)	N/NO (molar)
50	B and C	35 - 90°	4	0 - 3
60	C	34 - 90°	4	0 - 3
70	C	45 - 65°	4	0 - 3

Table 3-2. Parametric Test Program

3.5.3.2.1 50 MWe Results

For extended periods at 50 MWe, Arapahoe Unit 4 operates with two of four mills in service. Unless specific mills are out of service for maintenance, it is preferred to operate with the A and D mills (i.e., B and C mill out of service). This provides a uniform heat input distribution with the coal input biased evenly to the east and west sides of the furnace. This mill pattern was used for the 50 MWe tests. Figure 3-20 shows the effect of injection angle for N/NO molar ratios of 1 and 2. At both N/NO ratios the injection angle had a modest effect on NO_x reduction. The NO_x reduction decreases by about 5 percentage points as the angle increases from 45 to 90 degrees. The minimum injection angle is 22 degrees, at which the urea is injected parallel to the screen tubes. As the injection angle increases, the urea is injected into a higher temperature region of the furnace. At N/NO=1 the NH_3 slip was less than 2 ppm. At the higher urea injection rate (N/NO=2) the NH_3 slip decreased from 35 ppm at an injection angle of 35 degrees to 13 ppm at an injection angle of 90 degrees.

Figure 3-21 shows the performance of the DPSC lances as a function of N/NO ratio at an injection angle of 45 degrees. At this injection angle, 43% NO_x removal was achieved with 10 ppm NH_3 slip at a N/NO ratio of 1.8.

3.5.3.2.2 60 MWe Results

The majority of the parametric tests were conducted at 60 MWe as this is the most prevalent low load operating point. Figure 3-22 shows the performance of the DPSC lances as a function of N/NO ratio for injection angles of 34, 45, and 65 degrees. A single line has been drawn through all of the NO_x reduction points in Figure 3-22 as injection angle had little effect on NO_x removal for this boiler operating condition. Looking at the individual data points, NO_x removal performance was slightly better at an injection angle of 45 degrees than at either smaller or larger angles.

While injection angle had little effect on NO_x reduction, the injection angle had a major effect on NH_3 slip. There was a relatively small change in NH_3 slip as the angle increased

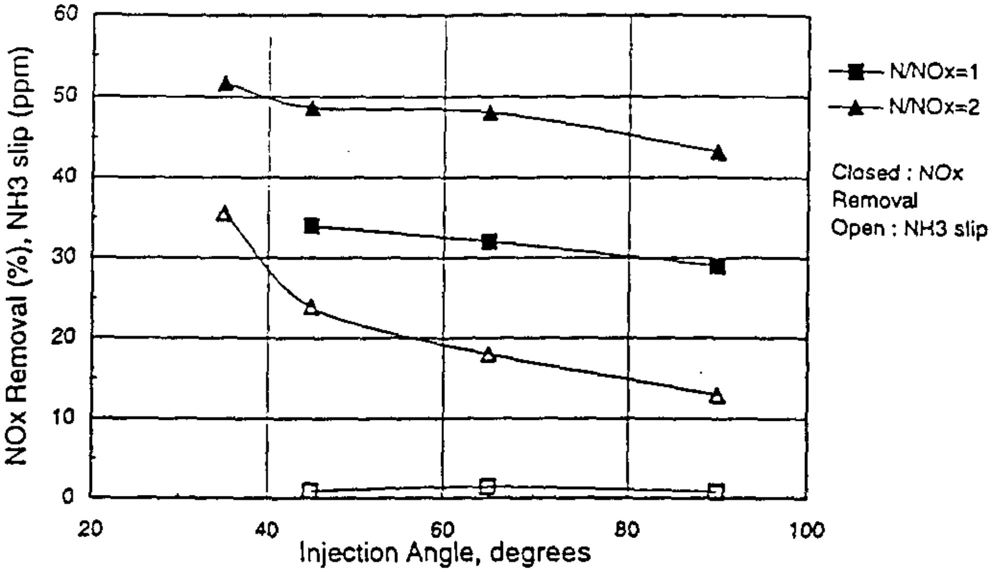


Figure 3-20. Effect of DPSC Injection Angle at 50 MWe
(Total Liquid Flow: 5 gpm, B and C mills OOS)

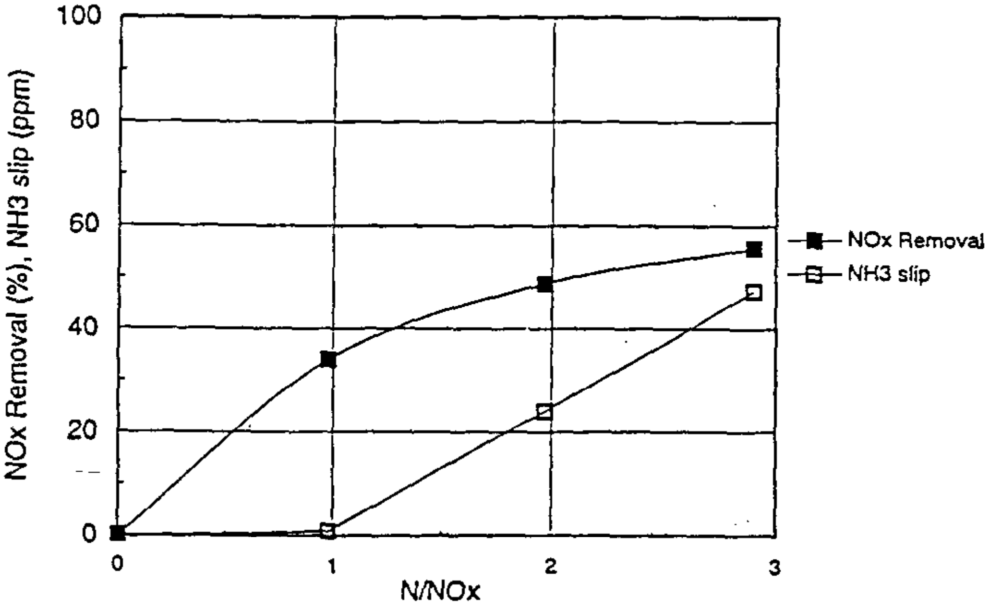


Figure 3-21. Effect of N/NO Ratio on DPSC Lance Performance
(Load: 50 MWe, B and C Mils OOS, Injection Angle: 45°, Total Liquid Flow Rate: 4 gpm)

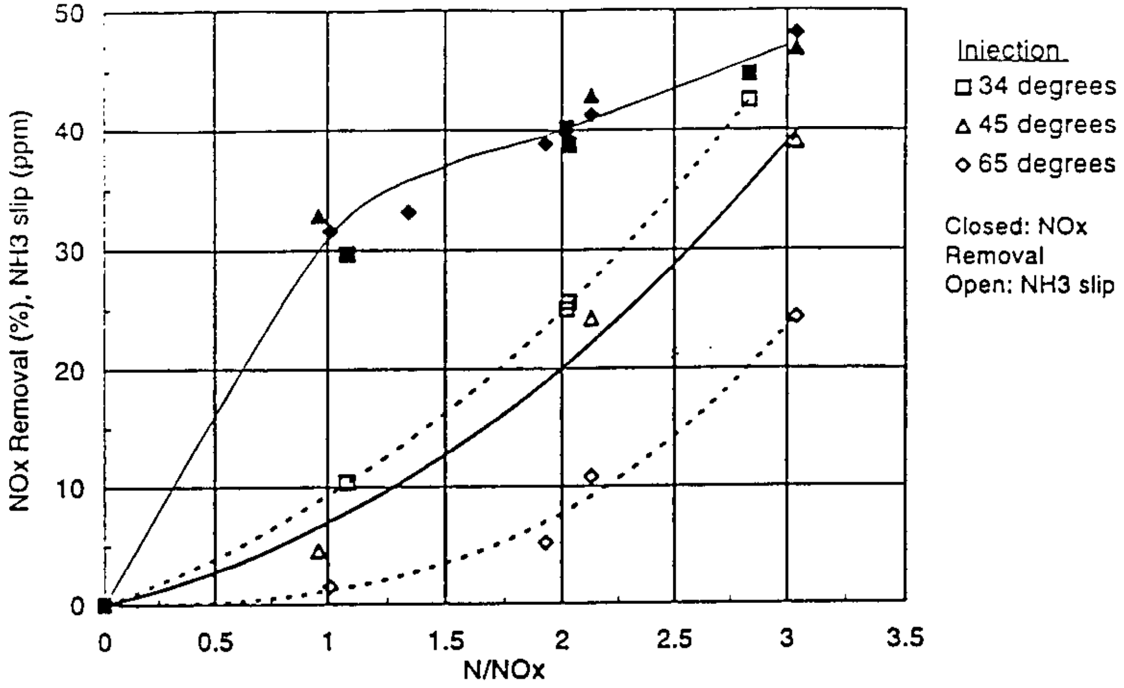


Figure 3-22. Performance of the DPSC Lances at 60 MWe (C Mill OOS, Total Liquid Flow Rate: 4 gpm)

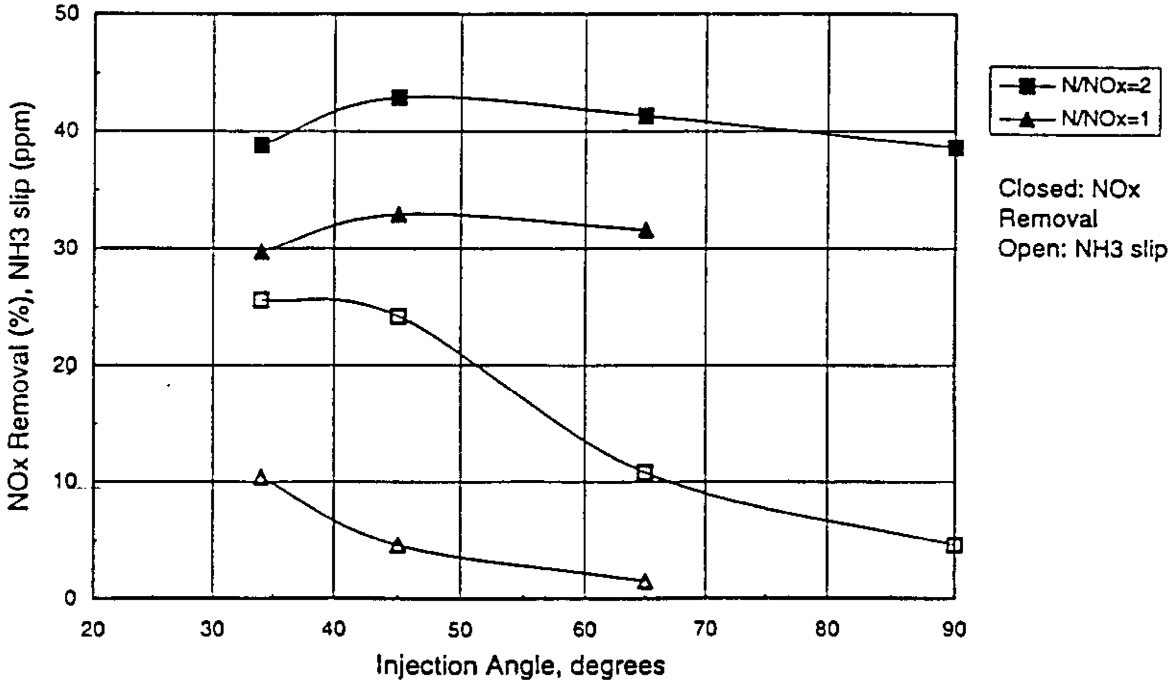


Figure 3-23. Effect of Injection Angle on DPSC Lance Performance at 60 MWe (C Mill OOS, Total Liquid Flow Rate: 4 gpm)

from 34 to 45 degrees. This small change in NH_3 slip along with the slight increase in NO_x reduction would suggest that at an injection angle of 34 degrees the injection was, on average, on the low temperature side of the SNCR window. The optimum injection angle in terms of NO_x removal is near an angle of 45 degrees. At the higher angle of 65 degrees, the NH_3 slip dropped quite dramatically with a NO_x removal of 42% at N/NO=2.2 with 10 ppm NH_3 slip. The effect of injection angle is shown more explicitly in Figure 3-23. Again, the decrease in NH_3 slip with increasing injection angle is evident.

With one coal mill out of service, the heat input to the furnace is unbalanced from side to side (east to west). Each coal mill feeds three burners, two on one side of the furnace and one on the other. For instance, with C mill out-of-service, two burners on the west side and one burner on the east side are removed from service. This will generally result in higher temperatures on the east side of the unit. This effect was investigated in detail during the ARIL lance tests, including possible approaches to deal with this temperature imbalance (Muzio, et al., 1997). Figure 3-24 shows the removals and NH_3 slips measured on the east and west sides of the furnace for a boiler load of 60 MWe and N/NO ratio of 2. The NO_x removals were fairly comparable on both sides; although NO_x removal was a little higher on the west side at injection angles of 45 and 65 degrees. The NH_3 slip was higher on the west side for all injection angles. The higher NH_3 slip on the west side was due to lower overall temperatures on the west side with C mill out of service. The prior work with the ARIL lances showed that the easiest way to deal with this imbalance was to have the operator bias the coal mills to compensate for the extra burner out of service on the west side. This was beyond the scope of the current test program.

3.5.3.2.3 70 MWe Results

With the current automatic control scheme, the injection lances are inserted when the load drops to 60 MWe and will retract when the load increases to 70 MWe. This overlap in the loads for insertion and retraction of the lances is necessary to prevent the lances from repeatedly being inserted and retracted during load following. Thus, there was need to

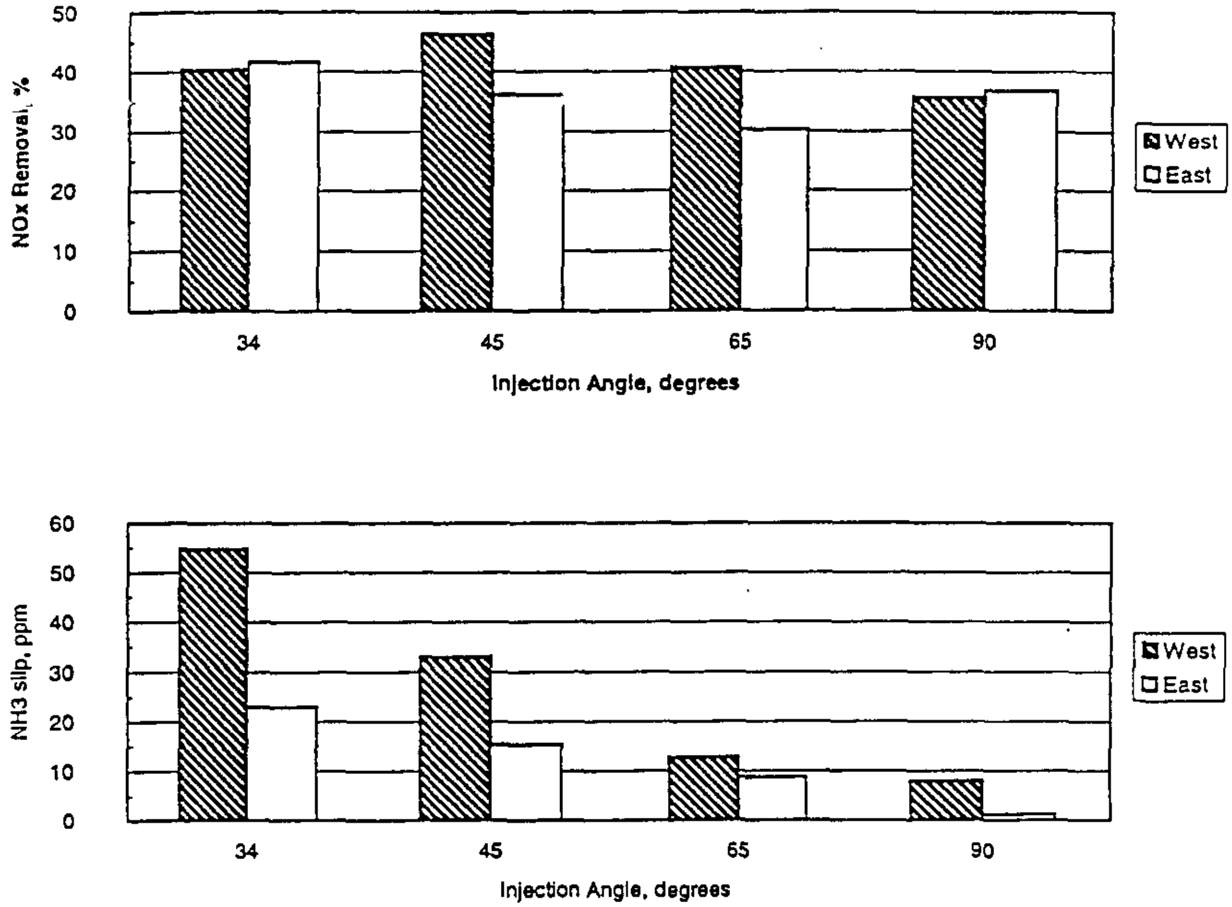


Figure 3-24. East-West Imbalances (Load: 60 MWe, C Mill OOS, N/NO = 2, Total Liquid Flow: 4 gpm)

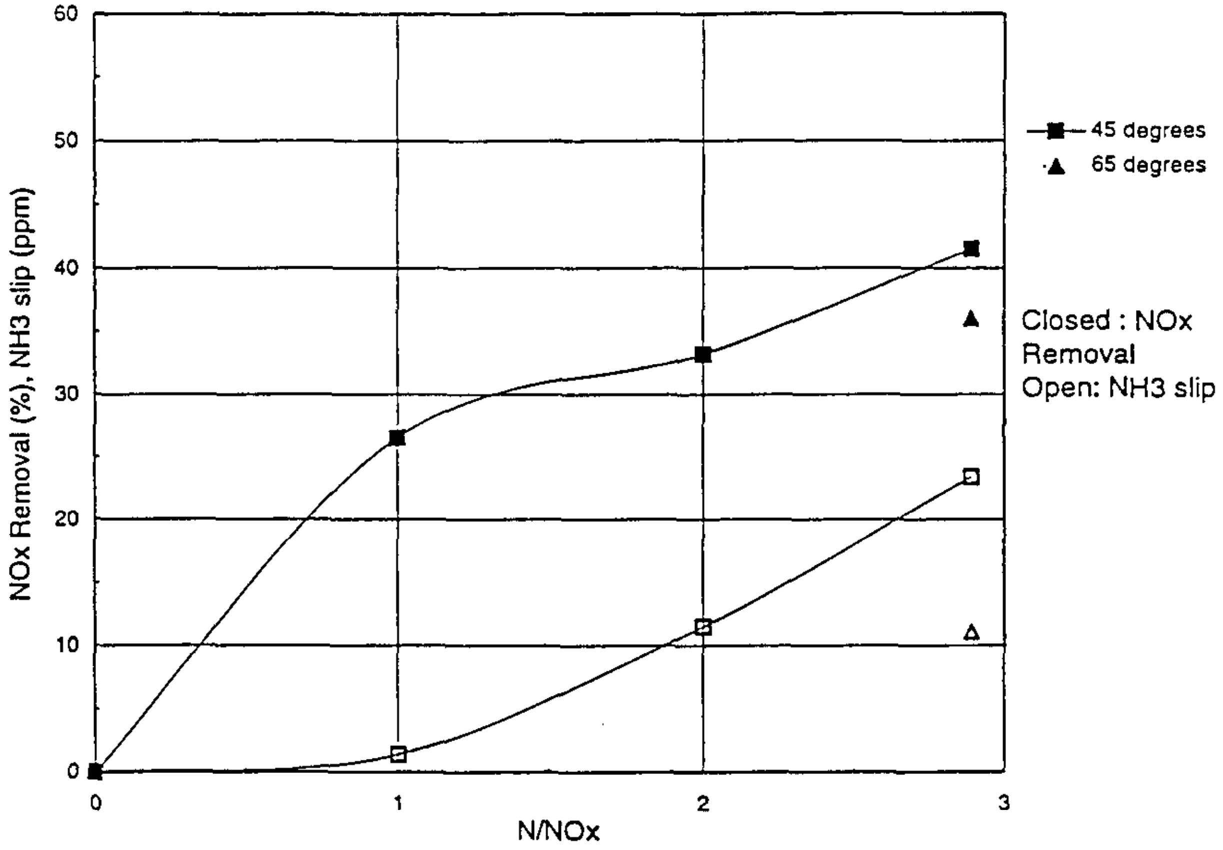


Figure 3-25. DPSC Lance Performance at 70 MWe
(C Mill OOS, Total Liquid Flow Rate: 4 gpm)

understand DPSC lance performance at loads up to 70 MWe. Figure 3-25 shows the performance of the DPSC lances at 70 MWe and injection angles of 45 and 65 degrees.

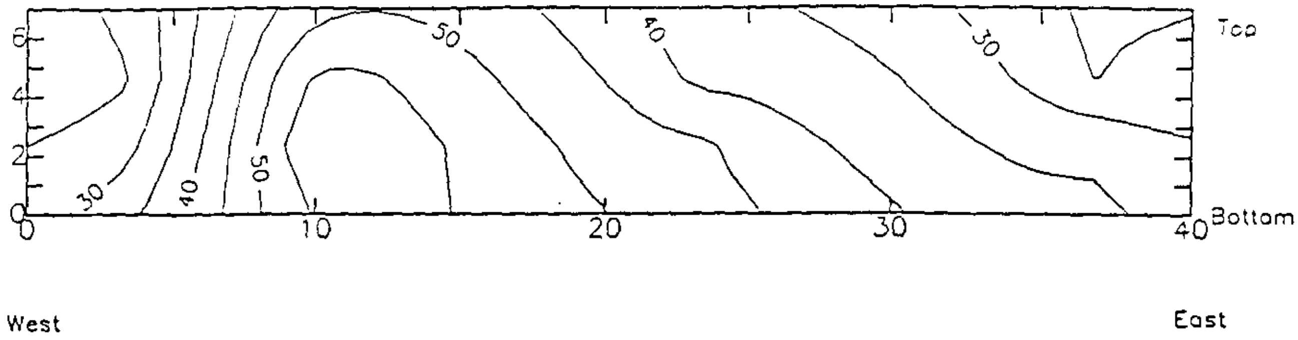
At an injection angle of 45 degrees, NO_x removal was 33% at N/NO=1.8 and an NH_3 slip of 10 ppm. Increasing the injection angle to 65 degrees resulted in injection into a higher temperature region with lower NO_x reduction and NH_3 slip for similar N/NO_x ratios. For a 10 ppm NH_3 slip limit, the NO_x removal increased to about 35% at the larger injection angle. However, this required a higher urea injection rate, N/NO_x=2.7, compared to N/NO_x=1.8 for a 45 degree injection angle.

3.5.3.2.4 Detailed Tests

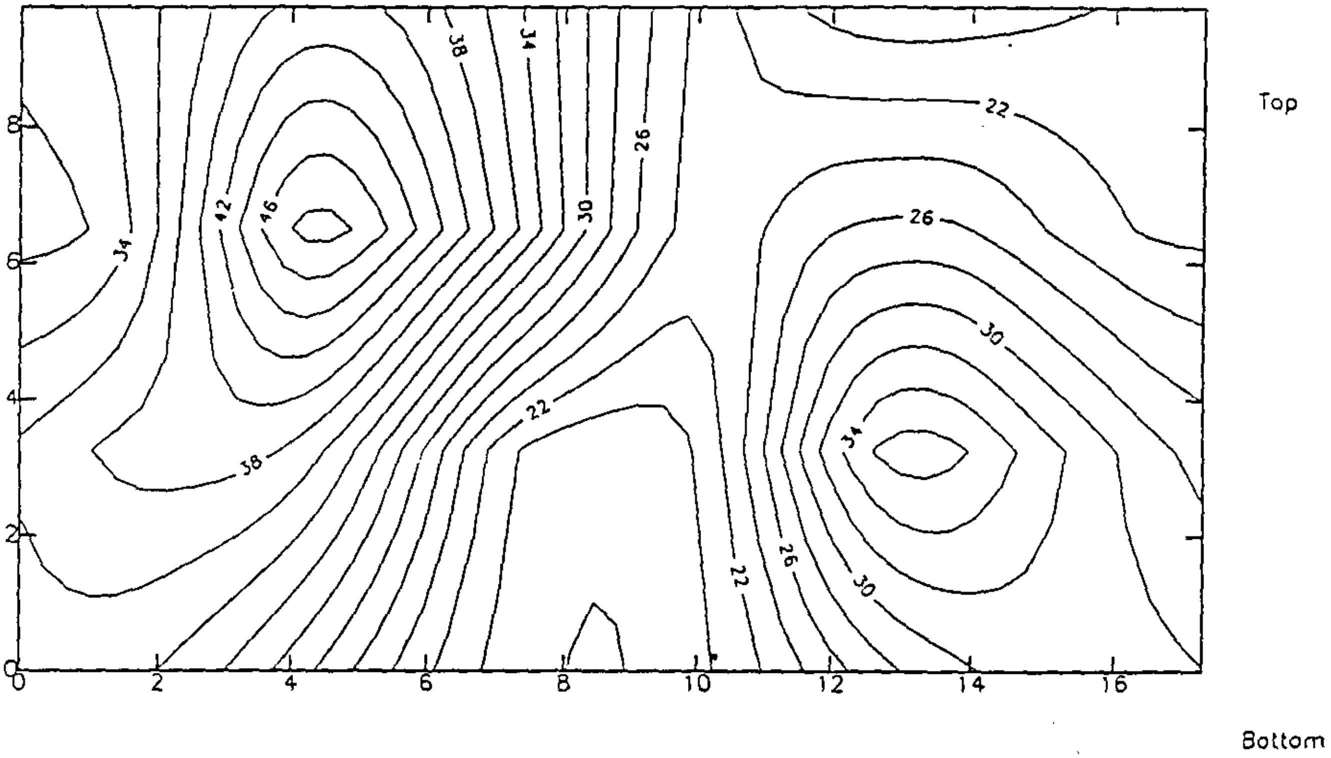
To gain a better understanding of the DPSC lance performance, a detailed test was performed at a boiler load of 60 MWe, injection angle of 45 degrees and N/NO=2. This test entailed point by point measurements of NO_x removal at the 12 point economizer exit probe grid; along with a 16 point NH_3 slip traverse at the air preheater exit. The resulting contour plots for NO_x reduction and NH_3 slip are shown in Figures 3-26(a) and (b), respectively. Before interpreting the contours in Figure 3-26, recall that changes in NO_x removal and/or NH_3 slip can be due to both temperature variations across the plane of urea injection and variations in urea distribution from the lances. Prior detailed tests with the ARIL lances tended to show relatively flat contours east to west with the primary variations being from the top to the bottom of the economizer duct.

Note that assuming plug flow of the flue gas from the lances to the economizer exit, the top of the duct corresponds to flue gas near the lances. The bottom of the duct corresponds to flue gas passing near the far wall away from the injectors. The prior tests with the ARIL lances showed lower NO_x removals at the bottom of the economizer duct indicating that the ARIL jets were not penetrating completely across the furnace (Muzio, et al., 1997).

The NO_x reduction results shown in Figure 3-26(a) show a somewhat different trend. With the DPSC lances, the stratification tended to be more west to east, rather than top to



(a)
NO_x Removal Contours at the Economizer Exit (12 Points)



(b)
NH_3 Slip Contours at the Air Preheater Exit (16 Points

Figure 3-26. Detailed NO_x and NH_3 Slip Contours with the DPSC Lances (Load: 60 MWe, C Mill OOS, N/NO = 2, Injection Angle 45°, Total Liquid Flow Rate: 4 gpm) bottom. Higher NO_x removals occurred toward the center of the furnace, away from the side walls, supporting visual observations that the unvaporized liquid tended to be carried toward the end of the lance.

The NH_3 slip contours in Figure 3-26(b) show two high NH_3 slip regions toward the centers on each of the west and east sides. On the west side, the region is toward the top of the duct. On the east side, the high NH_3 region is toward the bottom of the duct. Previous temperature measurements at the furnace exit showed a low temperature region at the center due to the furnace division wall. This low temperature region would tend to yield higher NH_3 slip. However, for this test, the center region of the duct exhibited the lowest NH_3 slip, suggesting that urea was not reaching the center, and the high NH_3 slip regions correspond to regions of locally high N/NO_x ratios. The NOx removal results on the west side, along with the NH_3 slip measurements, suggest that there was a tendency for the urea to be biased toward the center of each lance with a lesser amount being injected near the entrance and far end of the lance. Table 3-3 summarizes the point by point NO_x reduction and NH_3 slip measurements which were used to generate the contour plots in Figure 3-26.

3.5.3.3 DPSC and ARIL Lances: Performance Comparison and Automatic Control Settings

During the initial tests with the single DPSC Lance (Muzio, et al., 1997) and during the current tests, the DPSC lances operated with liquid dripping from nearly each injection hole. This occurred due to the atomized liquid drops impinging on the walls of the lances and essentially de-atomizing. A portion of this liquid literally dripped off the edge of the injection hole and a portion was entrained by the injection air and re-atomized. This re-atomized portion of the liquid should have a larger drop size distribution than the sprays from the ARIL lances. With a larger drop size distribution, it is expected that longer vaporization times are needed along with higher temperatures. Thus, for comparable performance, it was expected that the DPSC lance would require a larger injection angle

(a)

Economizer Exit; NO_x Reduction (%)

	West			East			
	28%	60%	52%	46%	38%	34%	Top Ave: 43%
	24%	55%	49%	38%	35%	24%	Bottom Ave: 38%
Average	26%	58%	51%	42%	37%	29%	
	West Average: 45%			East Average: 36%			

(b)

Air Preheater Exit: NH_3 Slip (ppm)

	40	33	15	16	34	34	Top Ave: 29
	34	47	--	--	47	20	Middle Ave: 37
	31	51	39	20	18	23	Bottom Ave: 30
Average	35	44	27	18	33	26	
	West Average: 34			East Average: 27			

Table 3-3. Point by Point NO_x Reduction and NH_3 Slip Measurements
(Load: 60 MWe, Injection Angle 45°, N/NO=2, Total Liquid Flow Rate: 4 gpm)

than the ARIL lance. Further, the portion of the liquid that drips toward the screen tubes should not result in much NO_x reduction; rather this liquid should be a source of NH_3 slip.

The ARIL and DPSC lance performances are compared in Figures 3-27 and 3-28 for loads of 60 MWe and 70 MWe, respectively. For both the DPSC and ARIL lance tests, the C mill was out of service and the total liquid flow rate was 4 gpm. At 60 MWe and an injection angle of 22 degrees, the NO_x reductions with the ARIL lance was a little lower than the DPSC lance at injection angles of 34-65 degrees. However, the NH_3 slip

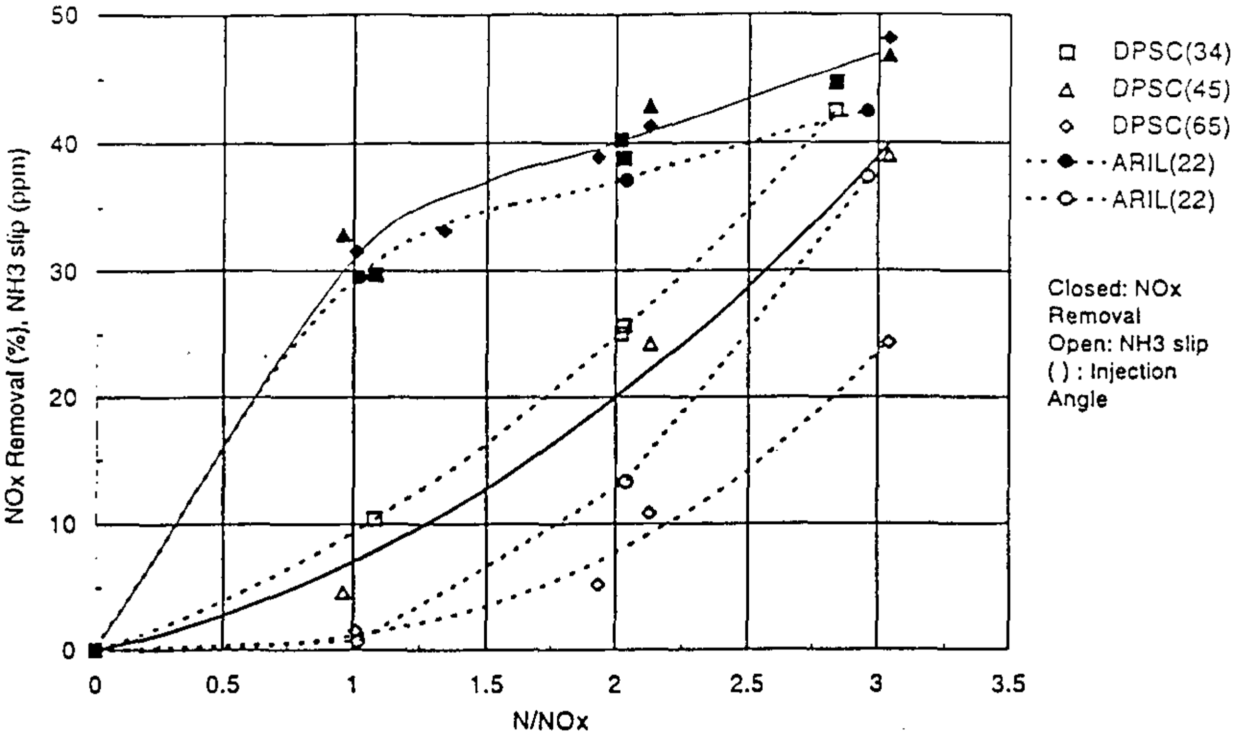


Figure 3-27. Comparison of the DPSC and ARIL Lance Performance at 60 MWe (C Mill OOS, Total Liquid Flow Rate: 4 gpm)

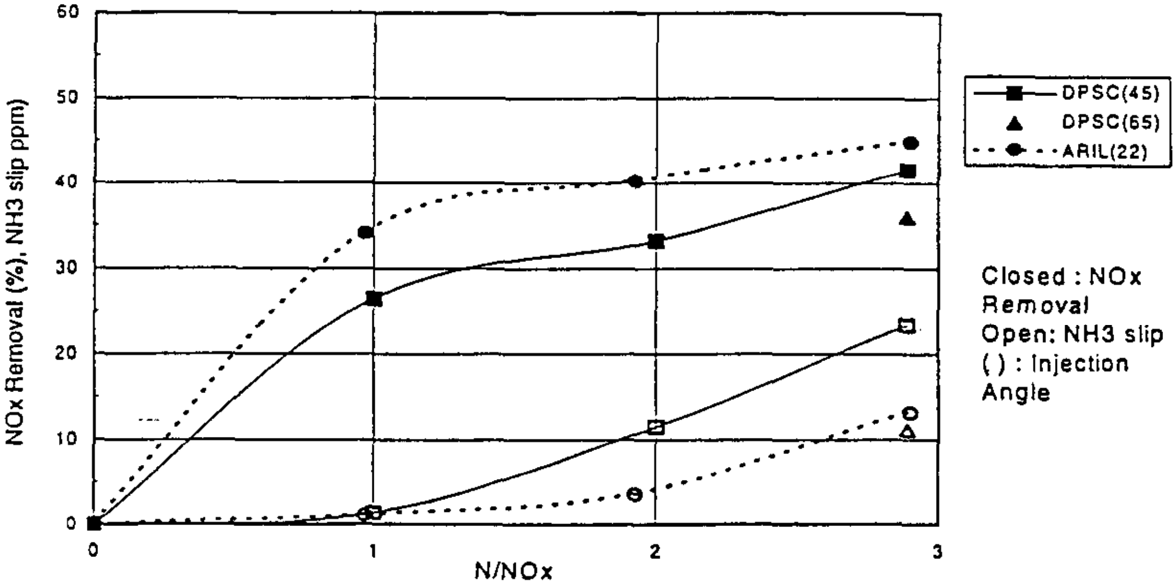


Figure 3-28. Comparison of the DPSC and ARIL Lance Performance at 70 MWe (C Mill OOS, Total Liquid Flow Rate: 4 gpm)

with the DPSC lance is higher than the ARIL lance. The DPSC lance required an injection angle between 45 and 65 degrees to produce the same NH_3 slip characteristics as the ARIL lance at 22 degrees. This supports the arguments above in terms of the coarser overall atomization with the DPSC lance, and the need to inject into a higher temperature region (i.e., larger injection angle).

Similar results are seen in Figure 3-28 for a boiler load of 70 MWe; except the NO_x reduction was higher with the ARIL lance at 22 degrees than the DPSC lance at 45 degrees. However, even at an injection angle of 22 degrees, the NH_3 slip was lower with the ARIL lances than the DPSC lance injection at 45 degrees.

The above comparisons were done at a common N/NO ratio and illustrate the general process temperature characteristics of the two different lances. For automatic operation, the real question is what NO_x reduction can be achieved at a specified NH_3 slip limit (i.e., 10 ppm) and at what urea injection rate (i.e., N/NO_x ratio)? This comparison is made in Table 3-4 using the data from Figures 3-27 and 3-28.

Lance (Angle)	Load			
	60 MWe		70 MWe	
	ΔNO_x (%)	N/NO (molar)	ΔNO_x (%)	N/NO (molar)
ARIL (22 degrees)	36	1.75	43	2.6
DPSC (34 degrees)	30	1.1	--	--
DPSC (45 degrees)	36	1.25	32	1.8
DPSC (65 degrees)	42	42	35	2,6

Table 3-4. Achievable NO_x Reduction at a 10 ppm NH_3 Slip Limit
(C Mill OOS, Total Liquid Flow Rate: 4 gpm)

At 60 MWe, Table 3-4 indicates that the DPSC lance can achieve comparable NO_x reduction at an angle of 45 degrees, compared to the ARIL lance at an injection angle of 22 degrees and at a lower N/NO ratio. At the higher load of 70 MWe, the ARIL lance can achieve 43% reduction at N/NO=2.7 compared to 35% for the DPSC lance operating at an angle of 65 degrees.

Overall, the NO_x reduction and NH_3 slip performance of both lances was quite good, and either lance design enhances the low load performance of the SNCR system. In general, the DPSC lance requires the urea to be injected into a higher temperature (i.e., larger injection angle) than the ARIL lance. Because of this difference in temperature characteristics, the relative performance depends on loads. At 60 MWe, the DPSC lance has a slight advantage being able to match the NO_x reduction of the ARIL lance, but at a lower N/NO_x ratio. However, at 70 MWe, the ARIL lance can achieve a higher NO_x reduction. Again, the relative performances of the two lance designs will also be dependent on the coal mill pattern, which could not be investigated during the current test program.

3.5.3.3.1 Recommended Lance Parameters for Automatic Operation

Based on the results of the parametric testing, settings for automatic control operation were developed for both the ARIL and DPSC lances. These parameters are shown in Tables 3-5 and 3-6 for the ARIL and DPSC lances, respectively. Note, tests of the DPSC lances have not been performed at loads less than 50 MWe, so the 43 MWe setting in Table 3-5 assumes that the N/NO ratio for the DPSC lances would have to be somewhat less than for the ARIL lances.

Load (MWe)	Injection Location	Lance Angle	N/NO Ratio	Total Liquid Flow Rate (gpm)	Atomizing Air Pressure (psig)
43	Lances	90°	1.15	4	10
50	Lances	45°	1.55	4	10
60	Lances	22°	1.60	4	10
70	Level 1	Retracted	0.65	2	8
80	Level 1	Retracted	0.85	2	8
90	Level 1	Retracted	0.75	4	8
100	Level 1	Retracted	0.95	6	8
111	Level 1	Retracted	1.55	6	8

Table 3-5. Recommended SNCR Settings for Automatic Control with ARIL Lances

Load (MWe)	Injection Location	Lance Angle	N/NO Ratio	Total Liquid Flow Rate (gpm)	Atomizing Air Pressure (psig)
43	DPSC Lance	90°	1.0	4	10
50	DPSC Lance	45°	1.5	4	10
60	DPSC Lance	65°	1.8	4	10
70	Level 1	Retracted	0.65	2	8
80	Level 1	Retracted	0.85	2	8
90	Level 1	Retracted	0.75	4	8
100	Level 1	Retracted	0.95	6	8
111	Level 1	Retracted	1.55	6	8

Table 3-6. Recommended SNCR Settings for Automatic Control with the DPSC Lances

Furthermore, it must be emphasized that the settings shown in Tables 3-5 and 3-6 are initial settings. These settings will be refined as continuous long-term operation proceeds. Also, the settings shown in Tables 3-5 and 3-6 are only starting points for the control system. The control system will increase, or decrease the urea flow rate to maintain a set point NH_3 slip limit at the FFDC exit. As such, the set point N/NO ratios (i.e., urea injection rate) are somewhat lower than the value expected to yield 10 ppm NH_3 slip. This was done to account for varying mill patterns and their effect on DPSC lance performance. It is preferable to have the control system trim the urea flow rate up, rather than down, which will avoid high excursions in NH_3 slip.

Based on the parametric test results and the settings shown in Tables 3-4 and 3-5, Figure 3-29 shows the expected average NO_x reductions over the load range for a 10 ppm slip limit for both the DPSC and ARIL lances. The curves shown in Figure 3-29 represent expected average performance. Varying boiler conditions can result in higher or lower NO_x reductions than shown in Figure 3-29. Both lances markedly improve the performance of the SNCR system below 80 MWe. In assessing the differences between the DPSC and ARIL lances shown in Figure 3-29, it needs to be reiterated that the 43 MWe point is just an estimate and the entire DPSC test program had to be performed with the C mill out of service. Some of these differences may disappear with further operation of the DPSC lances over a broader range of boiler conditions.

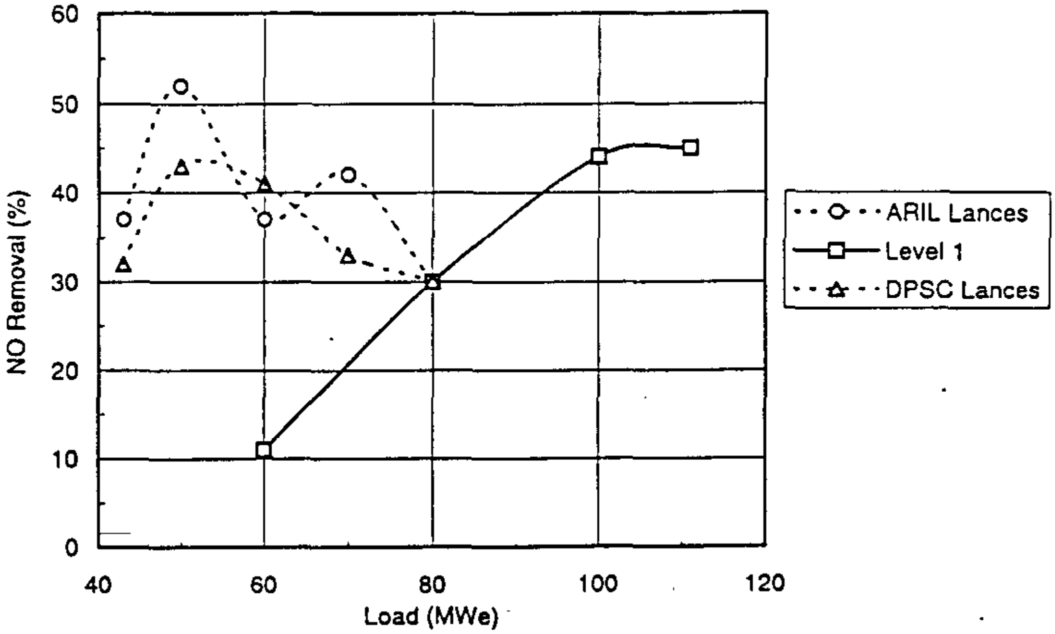


Figure 3-29. Projected NO_x Reductions Over the Load Range with 10 ppm NH_3 Slip

The results of long-term automatic operation of the ARIL and DPSC lances are presented in the subsection on integrated system performance.

3.5.4 SNCR Secondary Emissions and System Impacts

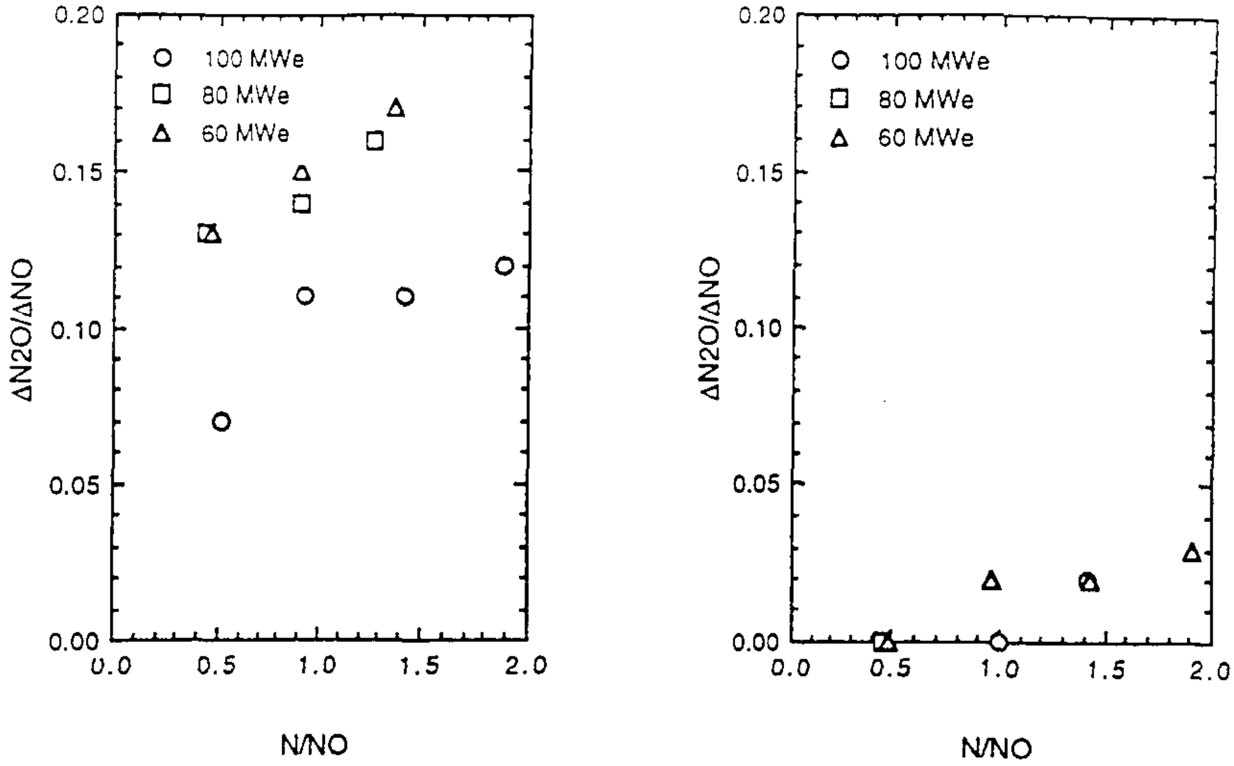
Secondary emissions resulting from SNCR processes primarily include N_2O and CO gaseous emissions. Other SNCR concerns include potential plume visibility, retention of ammonia on fly ash and other boiler impacts. These issues will be discussed as they pertain to the SNCR application at Arapahoe Unit 4.

3.5.4.1 Nitrous Oxide (N_2O) Emissions

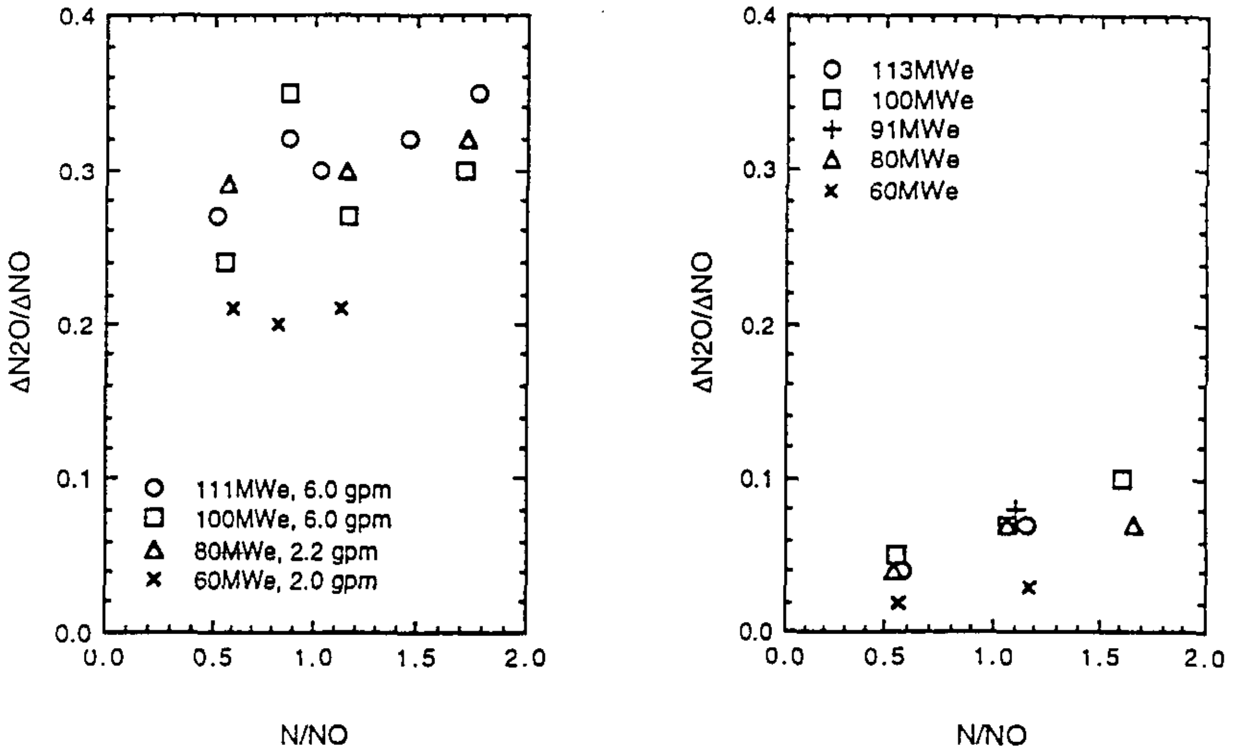
N_2O emissions are a byproduct of the SNCR process, and are dependent on the type of chemical reagent utilized, temperature and N/NO rates. N_2O emissions are shown as a function of N/NO ratio at various load for the baseline combustion system (urea and converted urea) in Figure 3-30. In these plots, the N_2O emissions are normalized by the amount of NO_x reduced by the SNCR system (i.e., the fractional the NO_x reduced that is converted to N_2O). N_2O emissions for the urea/baseline burner operation are shown in Figure 3-30(a). The N_2O conversion ranged from 7 to 17 percent and was consistent with previous urea studies. N_2O exhibits a temperature window similar to the NO_x reduction window with peak N_2O emissions occurring at nominally the same temperature as peak NO_x removals. Similar to the NO_x reduction results, the N_2O emissions are lower at corresponding 60 and 80 MWe loads. N_2O conversion also increases moderately with N/NO injection ratios.

Figure 3-30(b) shows the corresponding N_2O emissions for NH_4OH/baseline burner operation. Consistent with previous studies, N_2O emissions were significantly lower with NH_4OH injection and with less than 3 percent of the NO_x reduction converted to N_2O. The difference is due to the chemical paths for NO reduction for urea and aqueous NH_3.

Figures 3-30(c) and (d) show similar plots for the low NO_x combustion system with urea and converted urea. With the LNBs, the urea injection N_2O conversions increased to 20 to 35 percent, and because of the lower temperatures with the low NO_x combustion system, the highest N_2O occurs at the higher loads. Although higher on a percentage basis, the absolute N_2O levels were lower with the LNBs, due to the large change in NO_x



(a) Urea Injection with Baseline Burners (b) NH_4OH Injection with Baseline Burners



(c) Urea Injection with Low NO_x Burners (d) Converted Urea with Low NO_x Burners

Figure 3-30. SNCR N_2O Emissions

emissions between the baseline and retrofit burners. The reason for the large difference in the amount of. NO_x reduced that is converted to N_2O between the original and retrofit combustion system is not fully understood

Converted urea N_2O emissions with the low NO_x burners are significantly reduced to 2 to 10 percent, with no clear trend with boiler load. The converted urea significantly decreased N_2O formation, similar to the use of aqueous NH_3 that was demonstrated with the baseline burners. Relative to aqueous NH_3 operation, the converted urea N_2O conversion were higher on a percentage basis, which again may reflect the higher NO emissions of the baseline burners, or incomplete conversion through the catalyst.

For the ARIL and DPSC lances, the N_2O emissions were also dependent on lance injection angle. Again, varying injection angle varies the temperature experienced by the urea solution. For typical injection parameters, the N_2O emissions with the ARIL and DPSC lances were similar to the Level 1 injectors; N_2O varying from nominally 20 - 35% of the NO_x reduced.

3.5.4.2 Carbon Monoxide (CO) Emissions

Two mechanisms can lead to increased CO from the injection of urea. SNCR CO emissions may be enhanced from the partial oxidation of carbon contained in the urea First, the carbon in the urea may only be partially oxidized. Second, the SNCR chemistry can inhibit the oxidation of combustion generated CO in the vicinity of the injection process. In general, increases in CO emissions were low; for the baseline burners and urea at a N/NO ratio of 1.0, the maximum measured increase was 32 ppm. CO emissions decreased with higher boiler loads and lower urea injection rates. With aqueous ammonia and the baseline burners, the CO increase was lower, always less than 20 ppm.

The increase in CO emissions with the retrofit low NO_x burners was lower than baseline operation and remained under 20 ppm at all test conditions. With converted urea operation increasing, CO emissions were also low and were less than 20 ppm CO. There was no measurable increase in CO with the lance injection systems.

3.5.4.3 Plume Visibility

NH_3 slip from the SNCR system can react with HCl or SO_2 after the flue gas leaves the stack. Depending on the concentrations of NH_3, HCl, SO_2 and the temperature, this can lead to a detached visible plume. For typical flue gas concentrations of HCl and NH_3 solid ammonium chloride (NH_4Cl) will tend to form when the plume entrains air and the temperature drops below 250°F. SO_2 and NH_3 can react in the plume to form solid ammonium sulfite $(NH_4)_2SO_3$. For typical stack conditions, the NH_3/SO_2 reactions will only occur if the ambient air entrained into the plume is less than 32°F. At Arapahoe Unit 4, maintaining the stack NH_3 concentration below 10 ppm was generally sufficient to prevent visible plume formation. Although, there were occasions during the winter months when a visible detached plume occurred, presumably due to SO_2/NH_3 reactions forming an ammonium sulfite aerosol.

3.5.4.4 Fly Ash NH_3 Adsorption

Depending upon the fly ash chemistry, ammonia may be absorbed into the fly ash, which can cause ash handling, odor or ash salability impacts. With SNCR operation alone, conditions producing 10 ppm NH_3 slip at the air heater resulted in ash ammonia contents of 100 - 200 ppm (wt. basis) in the FFDC fly ash. With the SNCR system operating alone, no problems were encountered with NH_3 odors when handling the ash. As will be discussed in the section on integrated system performance, this was not the case when sodium was present.

3.5.4.5 Other Boiler Impacts

As discussed previously, a number of boiler operating parameters can affect the performance of the SNCR. Specifically, any boiler parameter that affects overall furnace exit temperatures, or the temperature distribution of the flue gas across the plane of the injectors. The previous discussion of the results showed how the SNCR parameters could be used to compensate for these changes (i.e., higher dilution water flow for local cooling, lances to compensate for the decrease in furnace exit gas temperature following the burner retrofit, biasing coal mill to compensate for a mill out-of-service, etc.).

Conversely, the SNCR system can also affect the boiler operations. The air used for injection and the evaporation of the aqueous urea solution can affect steam attemperation rates. At low loads, this could impact the ability to achieve required steam temperatures.

Another potential impact is the reaction of NH_3 and SO_3 in the air heater leading to deposition and plugging. Deposition and plugging will depend on the NH_3 slip and SO_3 concentration. At Arapahoe Unit 4, the SO_3 levels are less than 1 ppm and the unit uses a tubular air heater. Very long term operation would be required to evaluate air heater effects under these conditions. During the course of the demonstration, no detrimental air heater impacts were noted.

3.6 Environmental Performance

This section briefly summarizes the results of the environmental monitoring performed during the testing of the SNCR system after the installation of the low-NO_x combustion system. These results are reported in the *Environmental Monitoring Report: Low-NO_x Combustion System SNCR Test Period,* a copy of which is included in Appendix E. Environmental monitoring was completed according to the *Environmental Monitoring Plan for the Integrated Dry NO_x/SO_2 Emissions Control System,* dated February 1992 and its addendum dated July 1993.

Generally, the testing went well and there were no significant environmental events during the test period. Except for opacity, there were no excursions of any requirements during the tests. Opacity was in compliance 99.9% of the time during the testing of the SNCR system.

A significant amount of supplemental monitoring was completed to determine the emissions while operating and testing the SNCR system. During this testing, it was found that the SNCR system could substantially reduce NO_x emissions, but that it could also increase two emissions with potential negative effects: NH_3 and nitrous oxide (N_2O).

baseline testing included mercury (Hg) and chromium (Cr) speciation tests, a repeat sampling for VOC emissions, and measurements for dioxins and furans. Analytical laboratory problems, however, caused the contamination of the dioxin and furan samples and the results are not presented in this report. The dioxin and furan tests were repeated during the calcium-based dry sorbent injection test period.

In general, the air toxics data from this testing is comparable to the air toxics data obtained during the baseline testing and are reported in the *Environmental Monitoring Report: Low-NO_X Combustion System Retrofit Test Period.* The FFDC removed an average of 97% of the trace metals. The SNCR system did not affect the trace metal emissions, but, as expected, it did increase NH_3 emissions. The mercury speciation tests measured ionic-mercury (Hg^{+2}) and methyl-Hg in equal ratios. The chromium speciation tests found that approximately 4% of the total-Cr was hexavalent chromium (Cr^{+6}).

As the detailed data and results from the air toxics data is only published in the associated environmental monitoring report, the air toxics section of the reports are contained in the appendices of this report. Appendix B contains the baseline air toxics testing results for the baseline low-NO_x combustion system testing. Appendix C contains the air toxics testing results for the low-NO_x SNCR system testing.

4 SODIUM-BASED DRY SORBENT INJECTION

This section describes the technology used by sodium-based DSI systems to reduce SO_2 emissions and the DSI system at Arapahoe Unit 4. It also describes the objectives, methodology, and results of the test program. Section 5.0 describes calcium-based DSI with and without flue-gas humidification.

4.1 Description of Sodium-Based Dry Sorbent Injection Technology

DSI systems inject dry sorbents (reagents) into the flue-gas to control SO_2 emissions. The reagents are either calcium- or sodium-based. Generally, calcium reagents are injected into the flue-gas duct before the economizer; sodium- or calcium-based reagents are injected between the air heater and the particulate control device. Through a series of complex reactions, the reagents react with the gaseous SO_2 in the flue-gas to form a calcium- or sodium-based solid that can be removed by the particulate control device (FFDC or electrostatic precipitator).

DSI systems are simple, easily retrofitted to existing units, and have low capital costs. DSI systems include equipment for storing, conveying, pulverizing and injecting sodium- or calcium-based reagents into the flue-gas ductwork. They produce a dry, solid product that can be handled by conventional fly ash systems, but the use of DSI increases the amount of fly ash and adds soluble compounds to it. Because of the increase in fly ash, existing fly ash handling equipment may be inadequate. Because of the soluble compounds, the fly ash may not be slurried or sold as a concrete additive.

4.1.1 SO_2 Removal Chemistry of Sodium-Based Dry Sorbent Injection

The chemistry of sodium-based reagents to scrub SO_2 consists of a series of complex reactions. The following sections briefly summarize these reactions for the injection of the sodium-based reagents into the duct.

Sodium-based DSI systems inject one of two reagents into the flue-gas: sodium bicarbonate ($NaHCO_3$) or sodium sesquicarbonate ($Na_2CO3 \cdot NaHCO_3 \cdot 2H_2O$). Sodium bicarbonate is a refined form of nacholite and sodium sesquicarbonate is a refined form of trona. The injected reagent decomposes endothermically into soda ash (Na_2CO_3). The soda ash then reacts with the SO_2 in both the flue-gas duct and in the FFDC. Although it appears that it would be more efficient to inject soda ash directly, tests have shown that it is not effective at removing SO_2. It may be that directly injecting soda ash is not effective because it has much less surface area than the soda ash formed by the decomposition of the reagents.

In addition to SO_2, the sodium reagents also react with NO. It is not well understood how, but the injection of sodium-based reagents converts a small portion of the NO in the flue-gas to NO_2. Some of the NO_2 is removed as a solid so this decreases the overall concentration of NO_x, but increases the concentration of NO_2, a brownish orange gas. Thus, even though sodium-based DSI significantly reduces the stack emissions of pollutants, it can cause the stack emissions to become visible. The variables that affect the formation of NO_2 and a colored plume are not well understood, but they include the initial SO_2 concentration, the SO_2 removal rate, and the flue-gas temperature.

The decomposition of sodium bicarbonate and sodium sesquicarbonate into soda ash is complex and not well understood. The following equations show the generally accepted overall reactions for the decomposition of sodium bicarbonate (Eqn. 4-1) into soda ash and its subsequent reaction with SO_2 (Eqn. 4-2):

$$2NaHCO_3 \rightarrow Na_2CO_3 + H_2O + CO_2 \qquad \text{(Eqn. 4-1)}$$

$$Na_2CO_3 + SO_2 + \frac{1}{2}O_2 \rightarrow Na_2SO_4 + CO_2 \qquad \text{(Eqn. 4-2)}$$

The following equations show the generally accepted overall equations for the decomposition of sodium sesquicarbonate into soda ash (Eqn. 4-3) and its subsequent reaction with SO_2 (Eqn. 4-4):

$$2(Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O) \rightarrow 3Na_2CO_3 + CO_2 + 5H_2O \quad \text{(Eqn. 4-3)}$$

$$Na_2CO_3 + SO_2 + \frac{1}{2}O_2 \rightarrow Na_2SO_3 + CO_2 \quad \text{(Eqn. 4-4)}$$

4.1.2 Design Concerns of Sodium-Based Dry-Sorbent Injection

This section briefly summarizes the design concerns for sodium-based DSI systems. *Volume 1* more fully describes these concerns. The main criteria for designing a DSI system is the injection rate of the reagent. Once this rate is determined, the sizes of the subsystems may be determined. During the design stage, normalized stoichiometric ratio (NSR) and utilization data from other applications may be used to estimate the NSR and utilization at a specific unit.

Generally, sodium sesquicarbonate performs best in flue-gas temperatures below 300°F and sodium bicarbonate performs best at flue-gas temperatures above 300°F. As many factors affect the performance of a reagent, the effectiveness of the reagents should be tested at a prospective site.

Generally, sodium-based regents are injected into the flue-gas duct between the air heater and the particulate control device. The reagent may also be injected before the air heater where the flue-gas is hotter, but the reagent may cause plugging problems in the air heater.

The longer the distance between the air heater and the particulate control device, the longer the residence time for the reagent to react. In addition, if the particulate control device is an FFDC, the reagent collected in the FFDC continues to react with SO_2, lengthening the residence time from seconds to hours and improving both SO_2 removal and sorbent utilization.

The higher the initial concentration of SO_2 at the air heater, more reagent must be used, more NO_2 is produced by the reaction, and chances are more likely that a brown plume may form. As sodium-based DSI creates NO_2, high initial concentrations of NO_2 limit the flowrate of reagent and the SO_2 removal rate. The choice of sodium sesquicarbonate or sodium bicarbonate for duct injection depends on many site-specific factors.

Once the reagent injection rate is determined, the design of DSI storage systems for calcium- and sodium-based DSI systems depends on the reliability and frequency of the delivery of the reagent and the existing storage facilities at the site.

The fineness of the reagent particle affects how well the reagent reacts with the SO_2 in the flue-gas. Most sodium-based reagents require pulverizing. However, hydrated lime is very fine and does not require pulverizing. Decreasing fineness increases SO_2 capture but also increase pulverizing costs.

The effectiveness of both calcium- and sodium-based DSI systems also depends on the mixing of the reagent and the flue-gas. As with SNCR and OFA, since the total flow is constant, the more injectors the wider the dispersion of the reagent but the shallower the penetration. The higher the velocity of the injected reagent, the deeper the penetration, but the narrower the dispersion. The velocity and flow patterns of the flue-gas also affect mixing. The faster the flue-gas travels through the duct, the faster the reagent must be injected to reach the center of the duct or boiler before the flue-gas enters the economizer or particulate control device.

4.2 Sodium-Based DSI at Arapahoe Unit 4

Arapahoe Unit 4 uses two DSI systems to provide the capacity required for high sorbent flowrates and redundancy for low sorbent flowrates. Except for the splitters and injectors, the systems are identical and separate. The systems can inject calcium-based sorbents into the boiler before the economizer or into the flue-gas duct between the air heater and the FFDC. The systems were sized for sodium-based reagents, but the size was appropriate for hydrated lime at an NSR of 2.0. This section describes the storage, transport, pulverizing, and injection subsystems at Arapahoe Unit 4. Figure 4-1 shows a simplified P&ID of the DSI system.

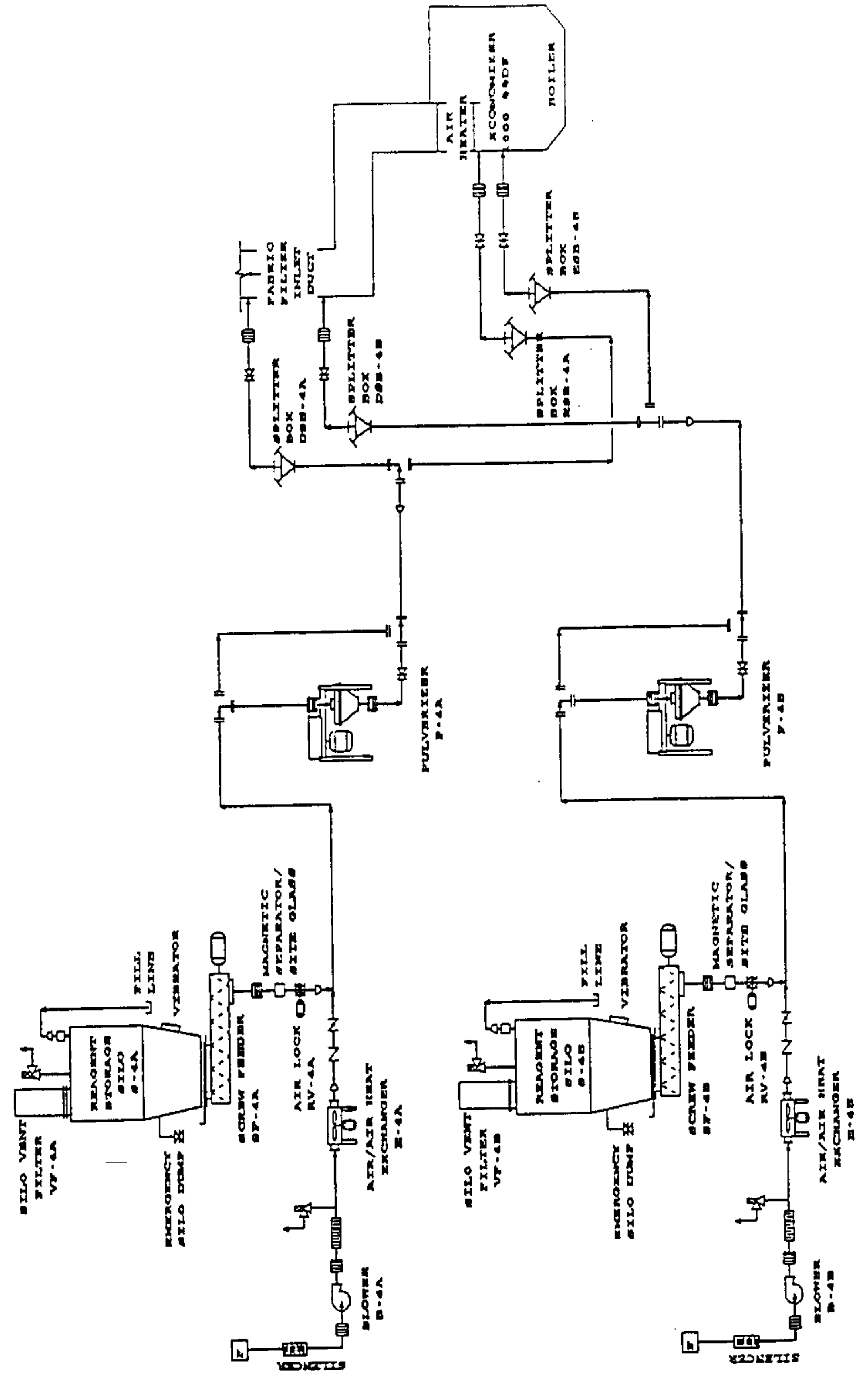


Figure 4-1. Simplified P&ID of DSI System at Arapahoe Unit 4

4.2.1 Storage

Each of the parallel DSI systems uses a silo to store either calcium- or sodium-based reagents. Each silo holds approximately 150 tons of reagent, enough for about 5 days use. Trucks deliver the reagents in granular form. Each truck holds approximately 25 tons and is equipped with blowers to fill the silos pneumatically. Each silo hopper is constructed of polished stainless steel and has steep angles (60°) to promote mass flow of the reagent from the silo. In addition, each silo is equipped with two vibrators to promote reagent flow when blockages occur. An ultrasonic level indicator measures the height of reagent in the silo.

4.2.2 Transport

A volumetric screw feeder meters the reagent and discharges it to the pneumatic conveying system through a constant-speed rotary airlock. The airlock provides a pressure boundary between the conveying pipeline at approximately 9 psig and the storage silo and the screw feeder at atmospheric pressure. Any air leakage is directed back to the silo through the bin vent filter.

The screw feeder is driven by a variable-speed motor and can be controlled automatically by the distributed control system (DCS) or manually. In automatic mode, the feeders are controlled as a function of the desired percent SO_2 removal. The DCS also uses feedback from the CEM to maintain the required feedrate of reagent. If unacceptable emissions of NO_2 exist, a second control loop is used. This loop limits the SO_2 removal to the maximum that can be obtained without generating a visible plume of NO_2 at the stack.

4.2.3 Pulverizing

Each DSI system uses a pulverizer manufactured by Entoleter. These pulverizers are rugged, compact machines that include a body, motor, rotor, liner, and discharge hopper. Over a feed range of 0.25 to 2 t/h, each pulverizer is designed to grind the reagents so that approximately 90% of if it will pass through a 400 US standard mesh sieve, or a mean diameter of 18 μm. A 60-HP motor drives each pulverizer. Generally, the pulverizers are used only for the sodium-based reagents, which are delivered granulated and then pulverized before they are injected into the flue-gas stream. The DSI system, however, is also designed to bypass the pulverizers while injecting hydrated lime since additional pulverizing is not expected to increase its utilization.

4.2.4 Injection

This section describes the DSI system's injection of sodium-based reagent into the duct before the FFDC. The length of the duct from the injection point to the FFDC is about 103 ft. long and the duct is fairly constant in cross section. The piping from each pulverizer connects to a splitter located on top of the duct. Each splitter separates the flow to the 6 injectors.

The injectors enter the duct and separate to form a 2-high by 6-wide grid of 12 nozzles. The nozzles from each of the systems are alternated so that the systems may be operated separately or together and still evenly distribute the reagent. The nozzles are oriented to inject reagent with the flue-gas flow. Although the DSI system is designed to obtain up to a 70% SO_2 removal rate with only one of the parallel systems injecting sodium-based reagents, using both systems results in a more uniform distribution of reagent in the duct.

4.2.5 Equipment Modifications Since Issuing Final Report, Volume 1

Two notable modifications were completed to the DSI system in order to address problems that developed during the test program. These included changing the airlock to a screw pump and modifications to the injection piping.

The original airlock was designed to allow limited leakage of the conveying air into the silo. It was discovered during the initial test stages that this leakage was higher than expected and caused an increase in the pressure below the screw feeder that affected the flow of sodium reagent from the silo. The test methods were revised to ensure accurate feed rata data was available, but the leakage become an operating concern during long term operation. Subsequent to the final long term test of sodium injection, the original airlocks on both systems were replaced with screw pumps designed by the Applied Performance Group located in Denver, Colorado. The screw pump is a small screw feeder that is mounted inside a pipe. The design is such that the conveyed material is used for form a solid plug of the conveyed material to provide an air seal and significantly reduce the air leakage. This equipment was much more effective than the rotary air lock and basically eliminated the problem of air leakage and its affect on the sodium feed rate during the long term testing.

The most common operating problem of the DSI injection system was pluggage of the injectors and piping located downstream of the splitter. The piping was insulated to prevent the possibility of condensing moisture from the conveying air. This provided a notable decrease in pluggage but did not solve the problem. The initial piping downstream of the splitter consisted of nominal 2" diameter carbon steel piping with standard long radius elbows. This piping was then connected to the injectors located in the duct elevation view as shown in figure 4-2. The sodium reagent would plug in all piping downstream of the splitter including the injectors. The piping after the splitter was modified so that the standard long radius elbows were replace with 3x radius elbows. The injectors located inside the duct were also cutoff just before the 90 degree elbows. This combination of modifications eliminated injector pluggage and greatly reduced pluggage at the splitter.

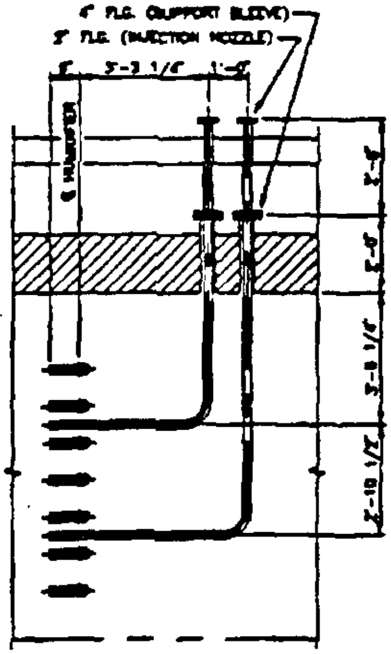


Figure 4-2. DSI Injection piping in duct

4.3 Sodium-Based DSI Test Program Objectives

The objectives of the sodium dry sorbent test program were to develop the performance data for sodium sesquicarbonate and sodium bicarbonate, in terms of SO_2 removal, NO_x removal, NO_2 emissions, and demonstrate long-term performance of the system.

The primary sorbent injection location was downstream of the air heater, at the inlet of the FFDC, although, some tests were performed injecting the sodium sorbents at higher temperature location ahead of the air heater. Humidification was briefly tested with sodium sesquicarbonate.

4.4 Sodium-Based DSI Test Program Methodology

The primary operating parameter for the sodium injection processes was the amount of sorbent injected, or the normalized stoichiometric ratio (NSR). The NSR is expressed as 2Na/S (molar basis), since the chemical reactions require two molecules of sodium to react with each molecule of sulfur (SO_2). Parametric variations of the 2Na/S ratio, sorbent type, and boiler load were performed for the sodium injection tests. In the cases when humidification was utilized, the primary operating variable of the humidification system was the approach to adiabatic saturation temperature of the flue gas over a range from 50 to 90°F.

The sodium DSI tests involved both short-term parametric tests and long-term tests. Long-term operation was primarily performed with sodium sesquicarbonate injection, which provided experience with normal boiler, load following operation and long-term FFDC performance. The parametric tests were performed with steady sorbent injection and humidification system conditions.

4.4.1 Instrumentation

The gas analysis instrumentation, as described previously, was utilized for the sorbent injection/humidification tests. SO_2 removals and NO_x removals were determined using the gaseous measurements at the economizer exit, air heater exit and FFDC exit. The FFDC exit measurements were used to assess NO_2 emissions.

4.4.1.1 FFDC Compartment Gas Measurements

In addition to the gas sample measurements at the economizer, air heater and FFDC exit, additional gas measurements were obtained from the exit of the individual FFDC compartments. A separate FFDC gas sample stream was added to the FERCo sample system and subsequently analyzed with the Altech CEM. Since accurate SO_2 emissions would be required from the FFDC compartment samples, a non-bubbling condenser and water dropout were added to the sample line just outside of the compartment sample location. During a boiler outage, a Teflon line was installed in the top of each compartment that was used to obtain a sample from the center of the compartment clean gas outlet opening. A fitting was installed on the door of each compartment to access this compartment gas sample. The compartment gas samples were acquired manually and required that the sample line and water dropout be moved and reconnected to each compartment during this measurement. This data was utilized to analyze the SO_2 removals and indirectly determine the sorbent distribution on a compartment-by-compartment basis.

4.4.1.2 Approach to Saturation Temperature

Please refer to Section 5.4.1 for a discussion of how the approach to adiabatic saturation temperature was determined.

4.4.1.3 Sorbent Feed Rate Measurement

The sorbent feed rate was an important measurement during the parametric tests. The project was intended as a full-scale commercial demonstration, with the equipment design reflecting a commercial configuration. As such, the sorbent feed system utilized volumetric feeders. The lack of an instantaneous gravimetric sorbent feed rate posed some problems in determining an accurate stoichiometric ratio (2Na/S) for the short-term parametric tests.

A calibration was performed by shutting off the rotary air lock, and opening up an access port and then calibrating with the discharge at atmospheric pressure. This raised a concern that when operating in the normal mode, the back pressure and the sorbent loss through the vent line could affect the feed rate, relative to the atmospheric calibration. A second calibration procedure was performed while the system was on-line, for each individual injector downstream of the sorbent distributor. A fabric filter bag was attached to the flexible hose downstream of the splitter, and a sorbent sample was collected and weighed from each injector line. Typically, this procedure yielded a feed rate approximately 10 to 20 percent less than the atmospheric calibration of the screw feeder for the sodium sesquicarbonate. Although, for sodium bicarbonate, there was no measurable difference between the two calibration methods. All data presented in this report are based on the injector calibration procedure.

4.4.2 FFDC Compartment Solids Sampling and Analysis

Samples of the sorbent and fly ash mixture were collected separately from the individual FFDC compartments in an effort to assess any variation in sorbent distribution and utilization within the FFDC. The solids analysis would also provide a means to check the 2Na/S ratio calculated from the sorbent feed rate. Initial sampling was performed by initiating sorbent injection, followed by a FFDC cleaning cycle to remove the untreated ash in the FFDC. The FFDC system was put in manual to prevent cleaning during the sorbent injection test. At the end of a test, an initial sample was collected which should represent material that fell into the hopper, or spent little or no time on the bags. The hoppers were then evacuated, a second set of compartment samples was obtained, which represented material that resided on the bags.

To obtain a representative sample from each hopper after the cleaning cycle, the following procedure was developed. This involved cleaning the FFDC in a normal fashion, and then manually evacuating each hopper one at a time while taking a sample from the bottom of the hopper at regular (one minute) intervals. This method provided a series of small samples which were representative of the vertical distribution of material in the hopper. Once the hopper was completely evacuated, the individual samples were composited into a single sample for that particular compartment. Samples were collected from all twelve compartments in a similar manner.

4.4.3 Test Methods

Parametric testing was performed by carefully controlling the various sorbent injection humidification and boiler variables in a systematic manner, to determine their effect on system operation, SO_2 removal, NO_x removal and NO_2 emissions. Key system variables include:

- Boiler load
- Sorbent Injection Rate (2Na/S ratio; 0 - 2.5)
- Humidification (Approach temperature; 50 - 90°F)
- Coal Type

For the parametric tests, the system was allowed to stabilize at the desired test conditions to insure steady state operation. During the test period, documenting system operation was performed by completing boiler control room, sorbent injection and humidifcation data sheets from the DCS control screens. Composite gas emissions at the economizer exit and FFDC exit locations were also obtained. Additional test data obtained for specific tests could include:

- Detailed gas or FFDC compartment emissions
- Sorbent samples
- FFDC hopper ash samples

Following completion of a single test, additional adjustments to sorbent injection or humidification variables were performed and the process repeated. The long-term tests were conducted with the system operating in an automatic control mode. Data was logged by the DCS and the CEM system.

4.4.4 Quality Assurance/Quality Control

4.4.4.1 Gas Measurements

The continuous emission monitor system was calibrated dailing using normal quality assurance requirments contained in CFR Part 60. Sample system integrity was checked before the first parametric test each day by verifying that the SO_2 emissions at the inlet agreed with the stack SO^2 emissions before beginning sodium injection.

4.4.4.2 FFDC Compartment Gas Measurements

The accuracy of the sample methodology for the FFDC compartment gas measurements was verified by a comparison between the CEM stack sampling location and the average of the compartment samples. These measurements showed very good agreement and indicated that the compartment gas sampling technique was valid.

4.5 Sodium-Based DSI Results

The results of the sodium DSI tests will be presented in the following subsections. The properties of the sodium reagents will be presented, followed by the sodium sesquicarbonate test results, sodium bicarbonate test results, and finally the CSM bench scale study.

4.5.1 Sorbent Characteristics

The sodium sesquicarbonate used during the test program was obtained from Solvay Minerals, Inc. of Green River, Wyoming. The sodium bicarbonate was obtained from NaTec Resources, Inc., Houston, Texas (solution-mined in Western Colorado). The chemical composition and physical characteristics of the two materials are shown in Table 4-1.

Material	Sodium Sesquicarbonate	Sodium Bicarbonate
Chemical Formula	$NaHCO_3 \bullet Na_2CO_3 \bullet 2H_2O$	$NaHCO_3$
Supplier	Solvay Minerals, Inc.	NaTec Resources, Inc.
Composition:		
Na_2CO_3	45.8%	--
$NaHCO_3$	36.3%	99.5%
Percent Na by Weight	29.8%	27.2%
Bulk Density	49 lb/ft^3	64 lb/ft^3

Table 4-1. Sorbent Characteristics

The particle size distributions for two sodium sesquicarbonate samples are shown in Figure 4-3. The mass mean diameter (MMD) particle size for the raw and pulverized (4000 rpm mill speed) sodium sesquicarbonate samples were 27.8 and 17.0 microns, respectively. The particle sizes were determined by sedimentation after the sample was ultrasonically dispersed in a liquid medium.

Pulverized sodium bicarbonate samples were analyzed for mill speeds of both 4000 and 5000 rpm. The results (Figure 4-4) showed that the MMDs for the raw, 4000 rpm, and 5000 rpm samples were 61.5, 24.3, and 18.8 microns, respectively. The data indicate that the reduced pulverized speed resulted in a slightly larger particle size distribution.

In addition to pulverizer speed, the particle size is dependent on the mass flow rate through the mill. Table 4-2 shows the MMDs measured for samples collected at four different sodium sesquicarbonate feed rates. The results indicate that at a pulverizer speed of 4000 rpm, particle size was not highly dependent on the sorbent feed rate.

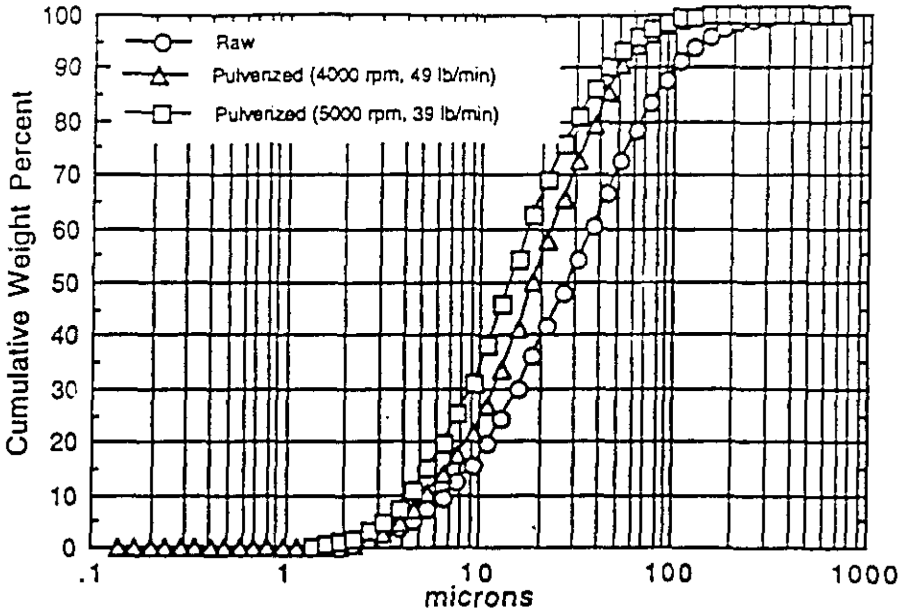


Figure 4-3. Sodium Sesquicarbonate Particle Size Distribution for Raw and Pulverized Samples

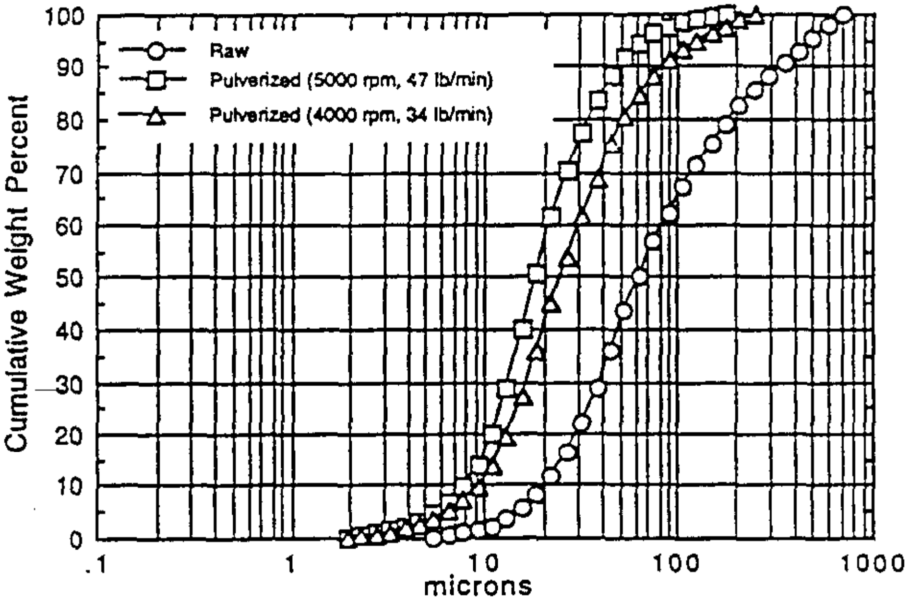


Figure 4-4. Sodium Bicarbonate Particle Size Distribution for Raw and Pulverized Samples

Feed Rate (lb/min)	2Na/S Ratio (nom. @ full load)	MMD (microns)
16.1	0.43	15.1
25.5	0.65	19.6
49.0	1.26	19.8
58.4	1.91	17.0

Table 4-2. Effect of Sodium Sesquicarbonate Feed Rate on Pulverizer Performance (Pulverizer Speed: 4000 rpm)

4.5.2 Sodium Sesquicarbonate Results

4.5.2.1 Injection at the FFDC Inlet

The majority of the sodium sesquicarbonate tests were run with sorbent injection ahead of the FFDC. A few tests were also run with humidification, since the equipment was already in place from the calcium test phase. The injection location was then moved to a higher temperature region at the air heater inlet. In addition, sodium sesquicarbonate injection tests were performed during a long-term evaluation and with the boiler operating with a Powder River Basin coal.

In general, the results with sodium sesquicarbonate showed that once injection had begun, SO_2 removals increased rapidly and reached steady state in a relatively short time period. The steady-state SO_2 removal results of many tests conducted during the program are presented as a function of sorbent injection rate at the FFDC inlet (2Na/S ratio) in Figure 4-5. Variations in boiler load were expected to have little effect on SO_2 removal, and the data confirm this expectation. At nominal 2Na/S ratios of 1.0 and 2.0, SO_2 removals range from 44 to 56 percent and 64 to 78 percent, respectively. Alternatively, the 2Na/S ratios required to achieve the target SO_2 removal of 70 percent ranged from 1.6 to 2.2. The FFDC outlet temperature at Arapahoe Unit 4 routinely varies from 230 to 280°F depending on load, time of day, and ambient temperature. Temperature had no effect on SO_2 removal over this temperature range.

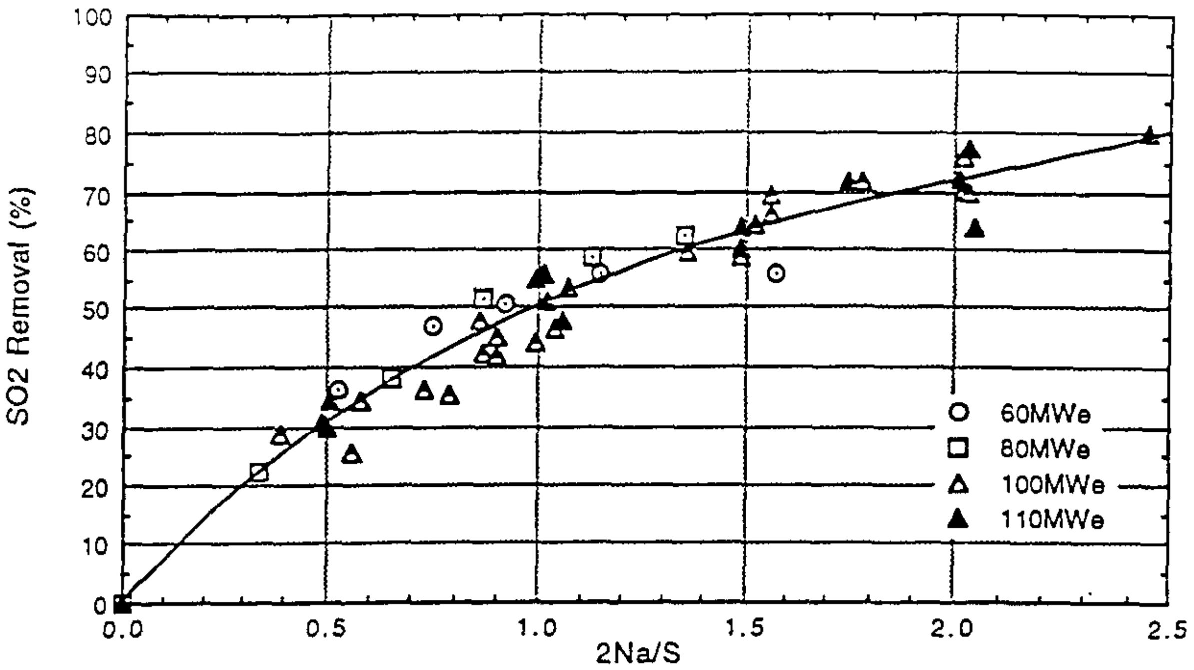


Figure 4-5. SO_2 Removal as a Function of Stoichiometric Ratio for Sesquicarbonate Injection Ahead of the FFDC

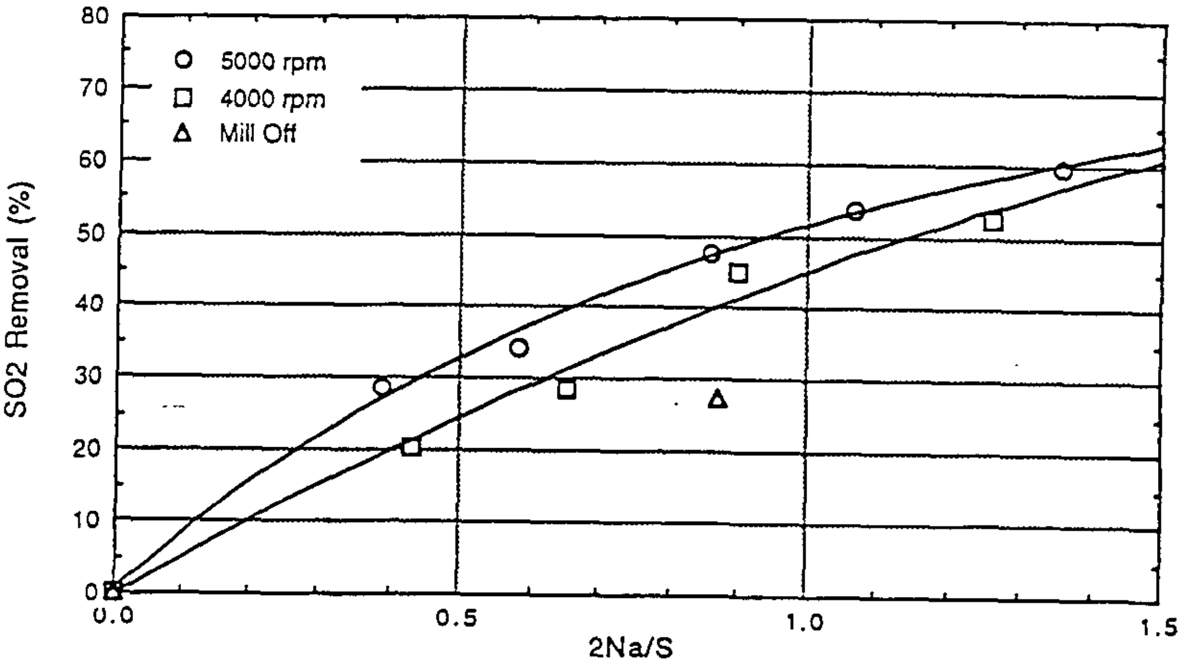


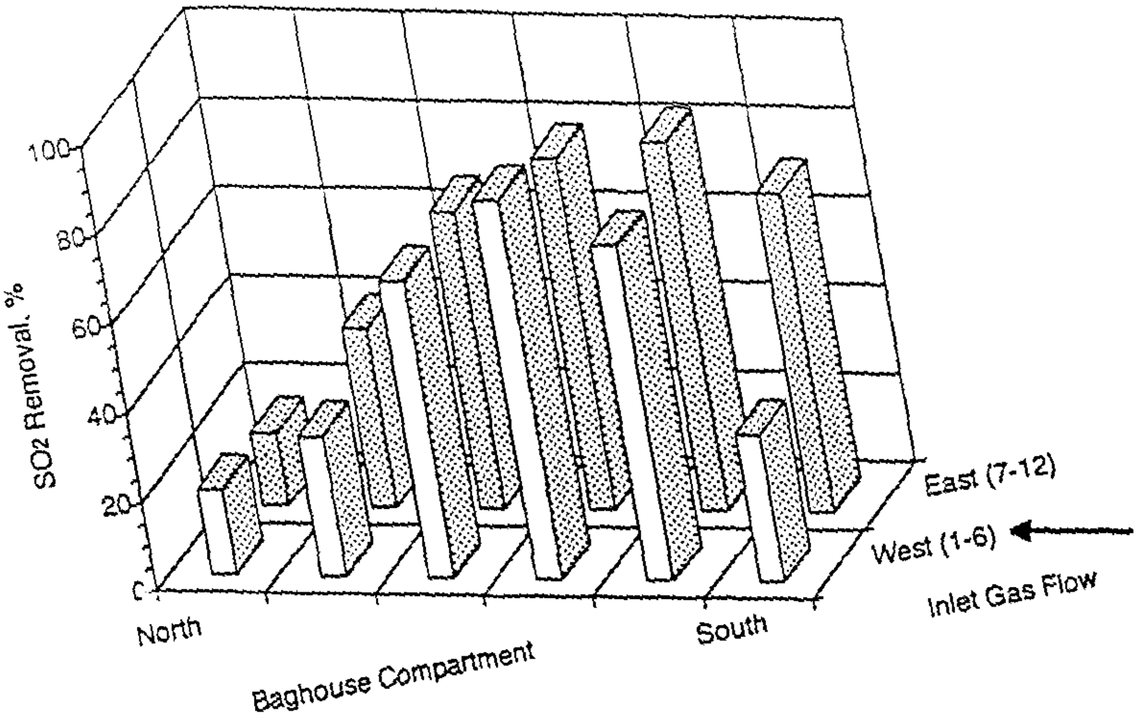
Figure 4-6. Effect of Pulverizer Speed on SO_2 Removal for Sesquicarbonate Injection Ahead of the FFDC

Figure 4-6 shows the effect of pulverizer speed on SO_2 removal for sesquicarbonate injection ahead of the FFDC. The pulverizers were run for a short time at 4000 rpm and the data show that the lower pulverizer speed results in approximately a seven percent decrease in SO_2 removal at a 2Na/S ratio of 1.0 from the normal run speed of 5000 rpm. The "mill off" point in Figure 4-6 is a single test run when the pulverizer was shut down while continuing injection. This test represents injecting unpulverized reagent. At 5000 rpm, the normal run speed, the mill reduces the particle MMD from 28 to 17 microns and the data show that this size reduction results in an increase in SO_2 removal from approximately 27 to 48 percent at a 2Na/S ratio of 0.9. Thus, pulverizing the sodium reagent increases efficiency substantially on Arapahoe 4.

4.5.2.2 FFDC Compartment Measurements

Compartment-by-compartment SO_2 removals were measured during a typical test with sodium sesquicarbonate injection. The boiler load was 100 MWe and the sorbent injection (2Na/S) was 1.5. These results, as well as the calculated utilizations for each compartment, are shown in Figure 4-7. The peak SO_2 removals occur in the central compartments of each side of the FFDC. The rear compartments had the lowest SO_2 removals of 15-20%. These results further support the observation that most of the sodium was deposited in the center compartments, and very little reaches the back compartments. The arithmetic average of the compartment SO_2 removal data was 55.9 percent. This compares very well to an overall SO_2 removal of 60.8 percent measured across the FFDC, indicating that the gas flow was balanced compartment-to-compartment.

Sorbent utilization was determined from the compartment SO_2 measurements and ash analyses. In general, the sorbent utilization data indicate that the material deposited in the rear compartments was more highly utilized than that deposited in the front. However, the sulfate and sodium ash analysis data indicate that more of the sorbent was deposited in the front compartments than in the rear. This resulted in higher 2Na/S ratios in the second and third compartments of the FFDC. While the SO_2 removals were high in these



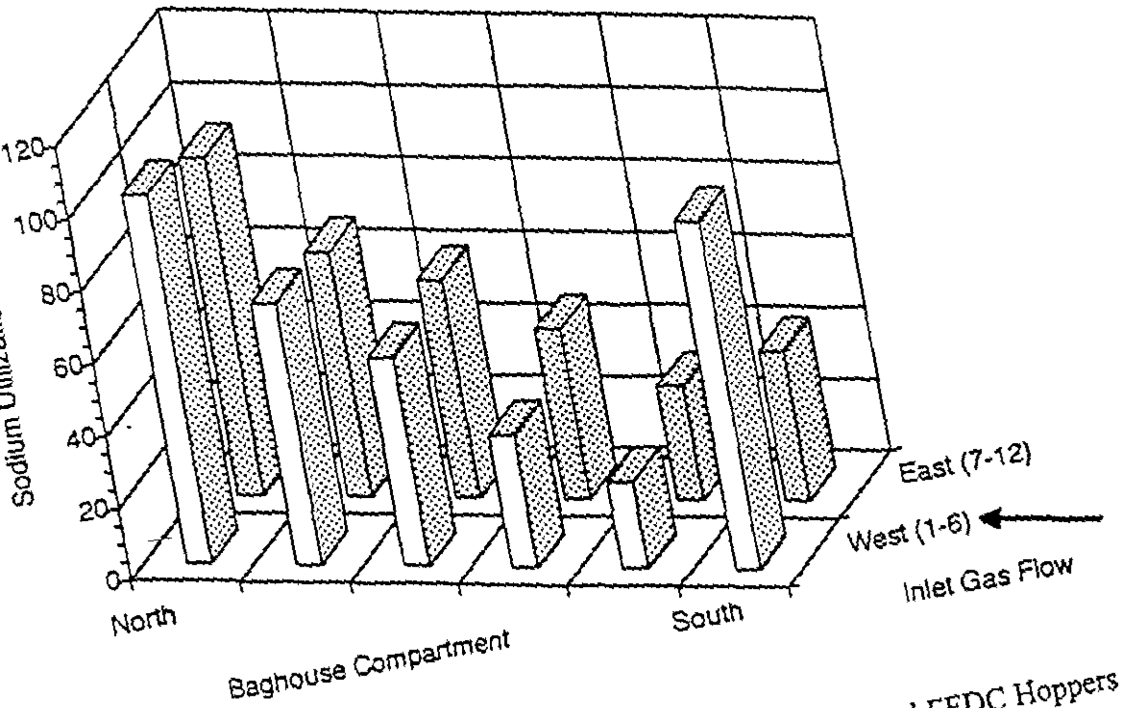


Figure 4-7. SO_2 Removal and Utilization Calculations for Individual FFDC Hoppers

compartments, the sodium utilization was low. The rear compartments, which had low SO_2 removal, also had high utilization rates, indicating that the sodium (2Na/S) delivered to this area was low.

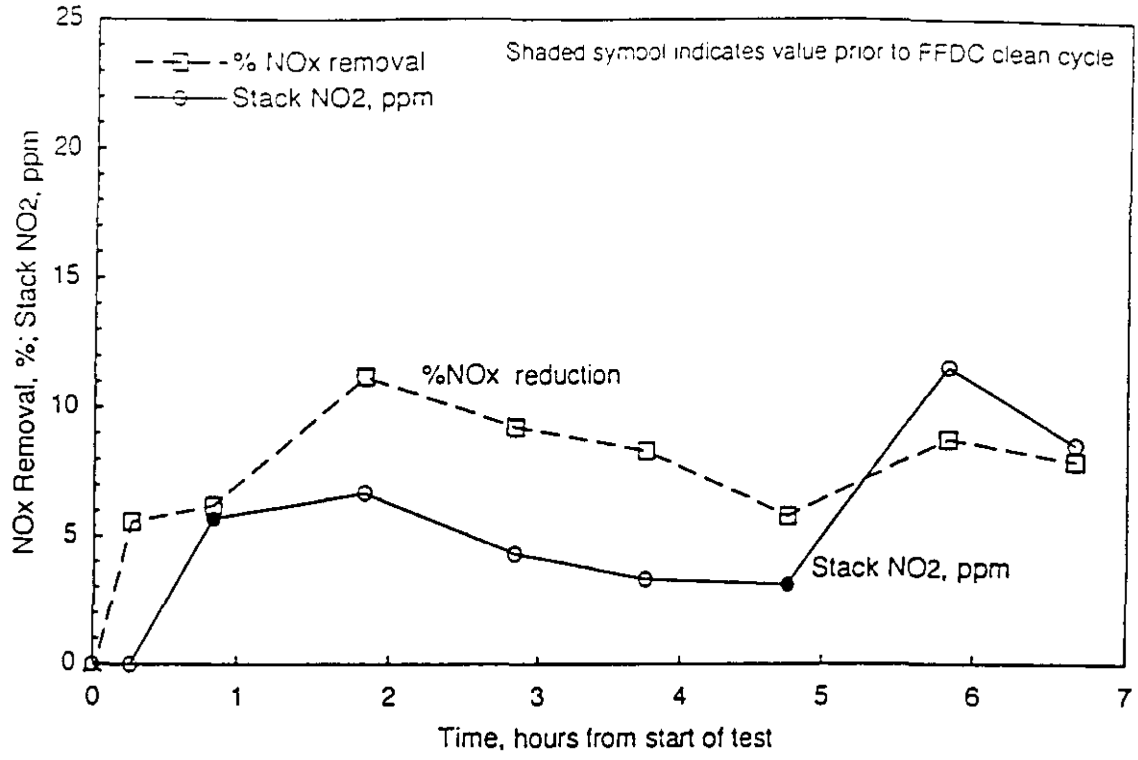
4.5.2.3 Injection at the Air Heater Inlet

Although injection at the FFDC inlet was the main focus of the sodium sesquicarbonate tests, limited tests were also performed at the higher temperature air heater inlet location. Comparing the average results between FFDC inlet and air heater inlet injection indicate that there was little difference in the steady-state SO_2 removals. However, the SO_2 removals, as a function of time for the two injection locations were found to be quite different. The initial SO_2 removal response time at the air heater injection location was much longer, and the level to which the SO_2 removal drops after a cleaning cycle was also lower. These observations indicate that the response time of the overall SO_2 removal process is slower when injecting sodium sesquicarbonate at the air heater inlet.

4.5.2.4 NO_x Removals and NO_2 Emissions

Previous studies showed that sodium-based sorbents also remove a small amount of NO_x as well as oxidize a portion of the NO to NO_2. During the current test program, NO_x removals and NO_2 emissions were characterized with both sodium sorbents.

Figure 4-8(a) shows both the NO_x removal and NO_2 emission traces recorded during the 7-hour test with sodium sesquicarbonate injection ahead of the FFDC at a load of 107 MWe. The NO_2 trace shows an interesting trend that was not reported previously, where NO_2 emissions increase sharply after each cleaning cycle. After the initial increase, there is a slow decrease in NO_2 emissions until the second cleaning cycle begins. This behavior was also seen during the long-term sodium bicarbonate injections tests, and will be discussed in more detail during the presentation of those results. It is currently thought that this behavior is due to an interaction between NO_2 and the fly ash on the bags. The peak NO_2 level achieved during the test shown in Figure 4-8(a) was 12 ppm. However, data points immediately after each cleaning indicate an increasing trend, and it



(a) NO_2 and NO_x Removal

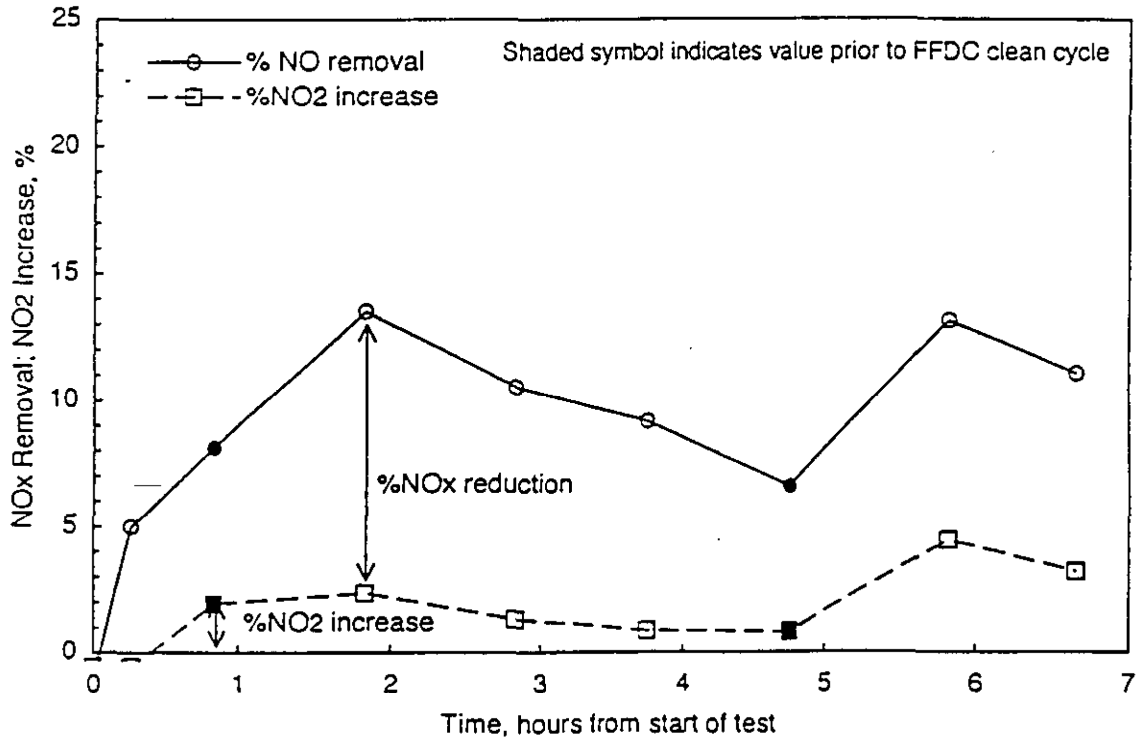


Figure 4-8. NO_x Removal and NO_2 Emissions versus Time for Sodium Sesquicarbonate Injection Ahead of the FFDC (Load: 107 MWe, 2Na/S: 1.5)

is possible that the peak level would have been higher if the test had been run for a longer time period. The NO_x removals shown in Figure 4-8(a) also indicate an increasing trend with time, but unlike the NO_2 emissions, there does not appear to be an effect of FFDC cleaning cycle. The range of 10 to 15 percent NO_x removal shown in Figure 4-8(a) is consistent with the levels observed during previous sodium dry sorbent studies. (Muzio, et al., 1994, Fuchs, et al., 1989).

The increase in NO_2 levels following a FFDC cleaning cycle are quite interesting and as mentioned above have not been reported in previous studies of DSI. The effect is due to an interaction between NO_2 and the fly ash on the bags. More specifically, it is currently thought that the interaction is with the carbon in the fly ash. Following the low NO_x combustion system retrofit while the carbon content of the ash did not increase, it did appear to change physically. Even though the ash carbon contents were still at the pre-retrofit levels, the ash visually appeared black. This suggests the possibility that the low NO_x combustion system may form some small soot particles that coat the ash particles. This fine coating of carbon on the ash could be more reactive than an equivalent amount of carbon more uniformly distributed through an ash particle. How the fly ash, or fly ash carbon interacts with the sodium generated NO_2 is currently not known. Possible mechanisms include physical absorption of the NO_2 by the carbon, catalytic oxidation of $NaNO_2$ to $NaNO_3$, or catalytic reduction of NO_2 to NO. The specific mechanism is currently not known; and the results indicate that the overall NO_x chemistry associated with dry sodium injection is even more complex than outlined at the beginning of this section.

Figure 4-8(a) showed the NO_2 levels and NO_x removal that occurred during the 7-hour test with sodium sesquicarbonate. As discussed previously, the chemical mechanism is thought to involve the formation of an unstable intermediate sodium compound, $NaNO_2$, and NO_x removal. This is shown in Figure 4-8(b) for the data in Figure 4-8(a). In Figure 4-8(b) the total height of the line plotted with the "circles" represents the total change in NO due to the sodium reactions. The dotted line represents the conversion of NO to NO_2. For instance, for the data point just before 2 hours, the total change in NO was about

13%; the NO_x removal was 11%, and the NO_2 emissions only represent 2% of the initial NO_x. Even after the second cleaning cycle, which started just before 5 hours, when the NO_2 increased from 3 ppm to 11 ppm, the majority of the NO that reacted was still manifest as NO_x removal.

Figure 4-9 summarizes the NO_2 emission measurements as a function of injection rate (2Na/S) and location for all of the sodium sesquicarbonate tests performed during the current study. There is a general increase of NO_2 with increasing sorbent injection rate, although there is a large amount of data scatter. The NO_2 emissions range from approximately 5 to 25 ppm with a 2Na/S ratio of 2.0. As discussed above, the NO_2 emissions depend not only on the injection rate, but also on the FFDC cleaning cycle, however there has been no attempt to correlate the data with respect to cleaning cycle timing.

Figure 4-10 summarizes the NO_x removals with sodium sesquicarbonate injection ahead of the FFDC. While there is scatter in the data, the NO_x removals ranged from 2 to 18 percent at a nominal 2Na/S ratio of 2.0.

4.5.2.5 Sodium Sesquicarbonate Injection with Humidification

A limited number of sodium sesquicarbonate tests were run with humidification in order to see if the SO_2 removals could be increased. Five tests were performed with an approach to saturation temperature of approximately 60°F, and one each with approach temperatures of 50 and 90°F. The data show that humidification results in increased SO_2 removals at higher sorbent feed rates (2Na/S ratios in excess of 1.0). At a nominal 2Na/S ratio of 2.0, the removals were increased from approximately 70 to 90 percent with an approach to saturation temperature of nominally 60°F. Data obtained at a 2Na/S ratio of 1.0 indicate that humidification had little effect.

Compartment-by-compartment gaseous emissions measurements were made during one of the humidification tests at an approach temperature of approximately 60°F with a nominal 2Na/S ratio of 1.0. With humidification, the SO_2 removals are relatively equal

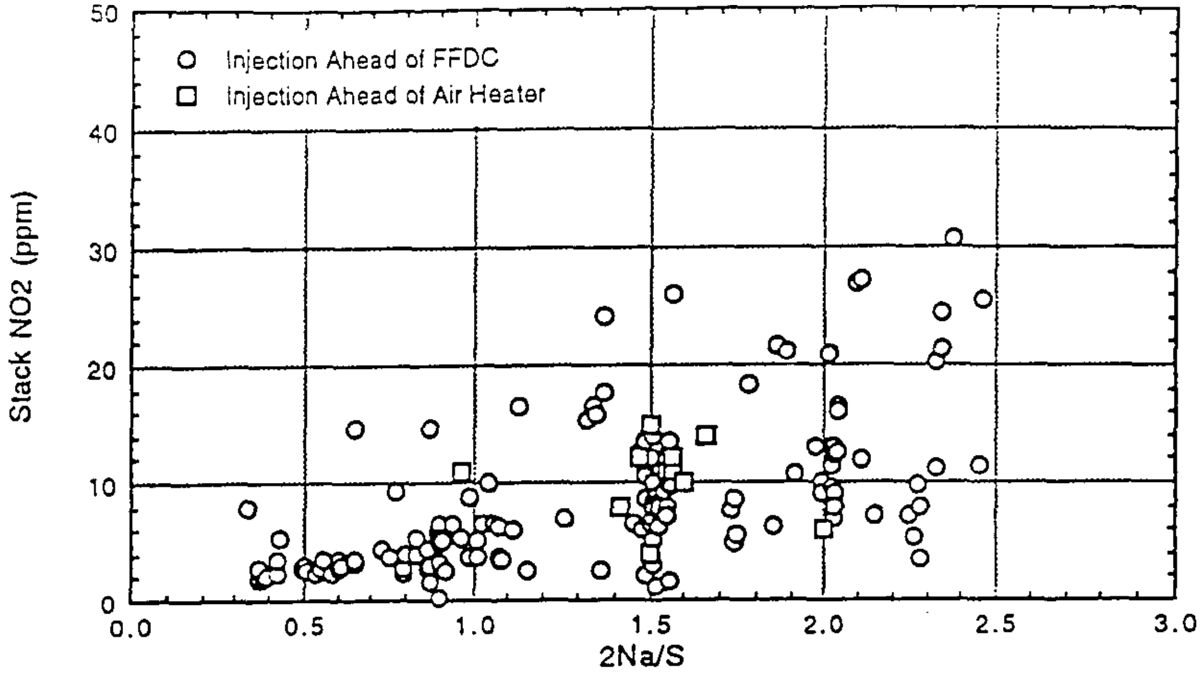


Figure 4-9. Summary of NO_2 Emissions with Sesquicarbonate Injection

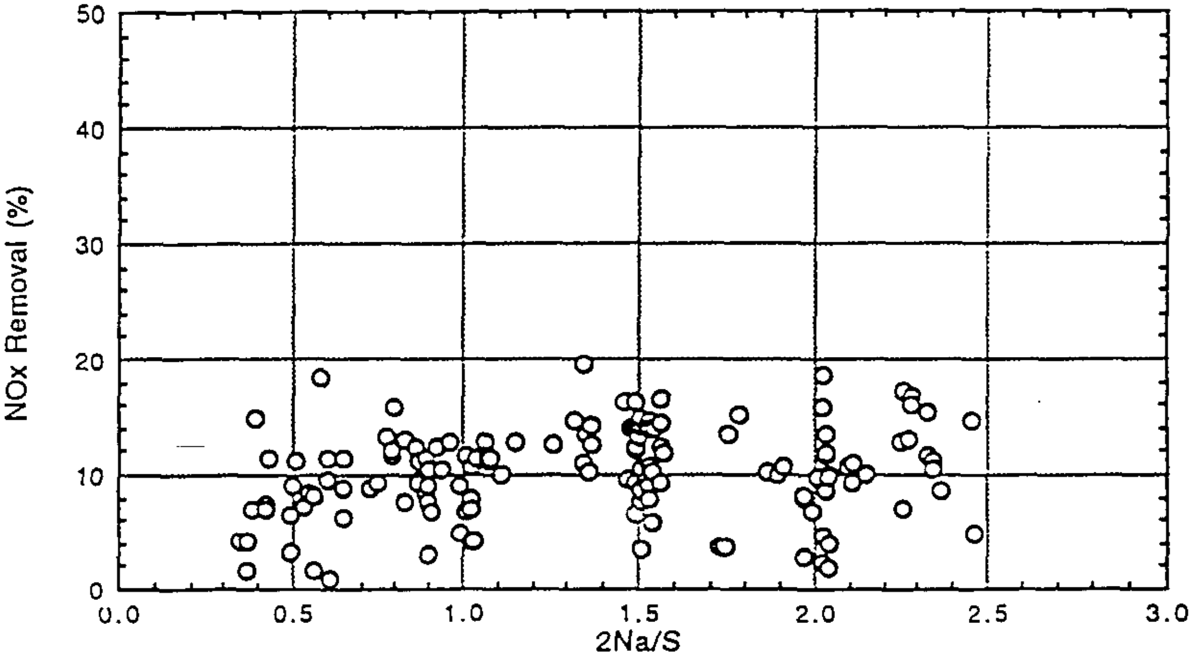


Figure 4-10. Summary of NO_x Removal with Sesquicarbonate Injection Ahead of the FFDC

among the compartments suggesting that more of the SO_2 removal occurred in the duct upstream of the FFDC. Moisture becoming associated with the sodium particles during the humidification process would be expected to increase the overall reactivity with SO_2, *thus allowing more of the SO_2 removal process to occur ahead of the FFDC.*

4.5.2.6 Alternate Coal Test with Sodium Sesquicarbonate

PSCC conducted a test burn of a sub-bituminous Powder River Basin (PRB) coal at the Arapahoe Station. The effect of the PRB coal on the performance of the DSI system was assessed over a period of two days. The sodium sesquicarbonate was injected into the duct at the FFDC inlet location with no humidification at rates corresponding to 2Na/S ratios of 1.0 and 1.5, and at loads of 65 and 80 MWe, respectively. The level of SO_2 removal reached at the conclusion of the 2Na/S = 1.0 test was 42 percent, while 59 percent removal was achieved at the higher sorbent feedrate. Figure 4-11 shows that these levels of SO_2 removal compare well with the results presented earlier in this report for the test with the bituminous Cyprus coal normally fired at the station.

Figure 4-12 shows the NO_2 emissions as a function of time for the two sodium-injection tests with the PRB coal. Data from a test with the normal Cyprus coal at 2Na/S = 1.5 is also included and shows a NO_2 emission spike after each FFDC cleaning cycle, followed by a slow decrease between cleanings. However, with the PRB coal, the NO_2 increased immediately and reached levels well in excess of those seen during the Cyprus test. The difference in behavior supports the hypotheses regarding the interaction between NO_2 and fly ash carbon in the FFDC, because the carbon content (LOI) of the PRB fly ash was lower than that for the normal Cyprus coal. With the Cyprus coal and nominal 2Na/S ratio of 1.0, the majority of the NO_2 levels were within the range of 2 to 7 ppm, and increase to a range of 5 to 15 ppm at 2Na/S = 1.5. With the PRB coal, these ranges increased to ranges of 20 to 26 ppm and 25 to 35 ppm, respectively.

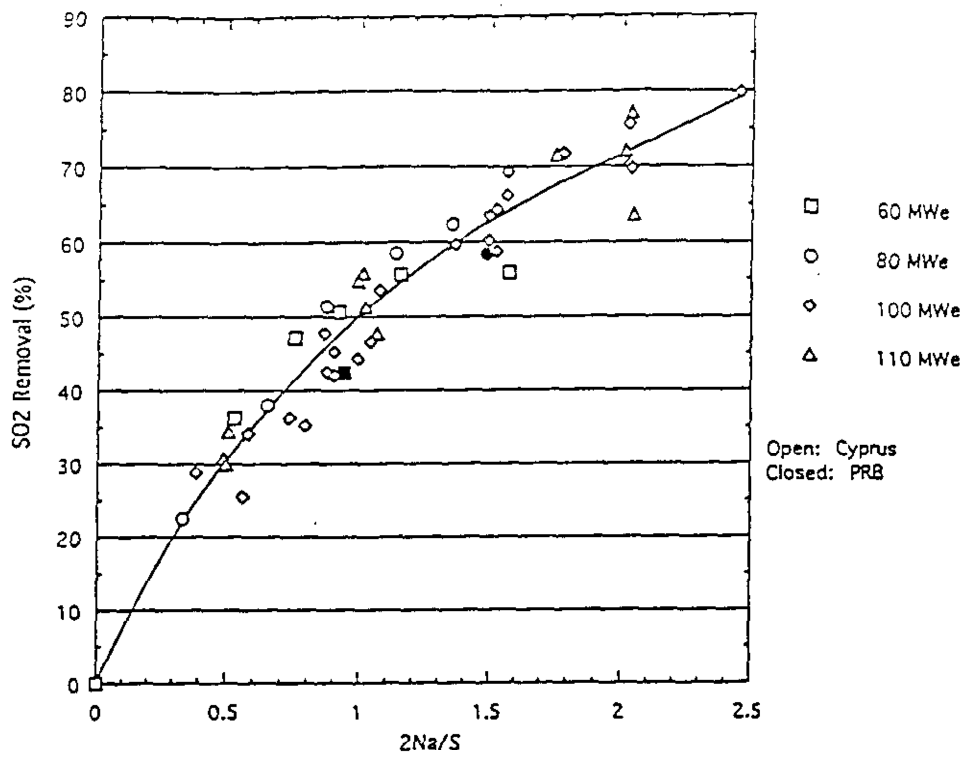


Figure 4-11. Comparison of SO_2 removals with Sodium Sesquicarbonate Injection Ahead of the FFDC for Cyprus and Powder River Basin Coals

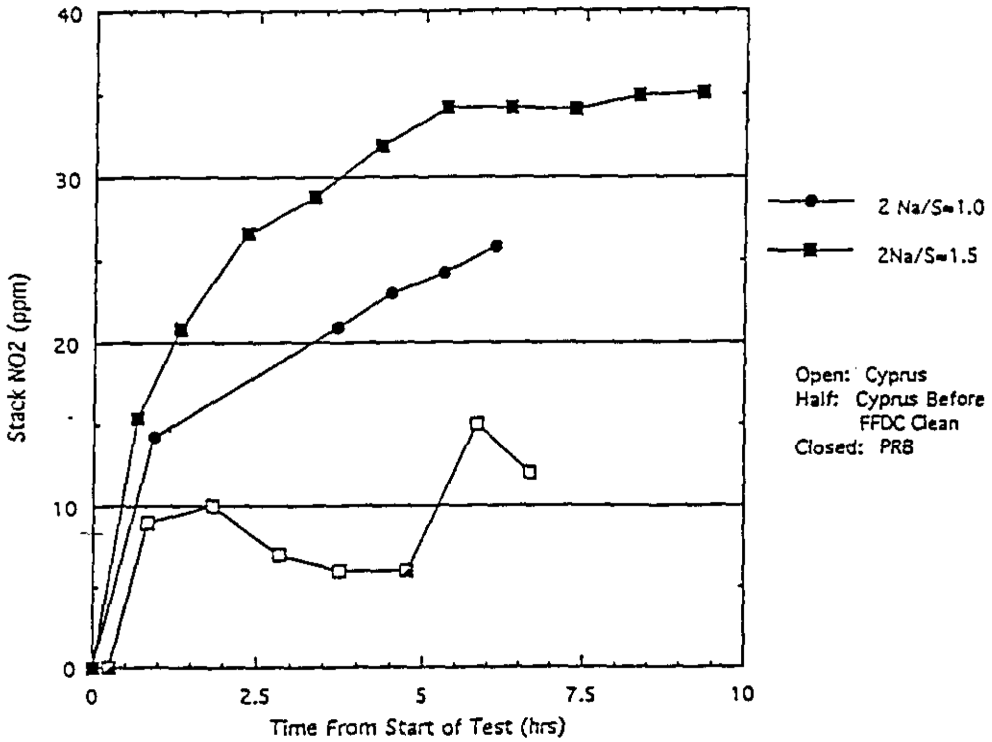


Figure 4-12. NO_2 Emissions versus Time with Sodium Sesquicarbonate Injection Ahead of the FFDC for Cyprus and Powder River Basin Coals

4.5.2.7 Long-Term Load Following Test Results

A long-term test was conducted with sodium sesquicarbonate injection ahead of the FFDC with the boiler in a normal load following mode. The goal was to maintain an average SO_2 removal of 40 percent for a period of time, then increase the set point to 70% SO_2 removal for another time period. Due to equipment problems, system operation at 70 percent SO_2 removal was only possible for a shorter test period.

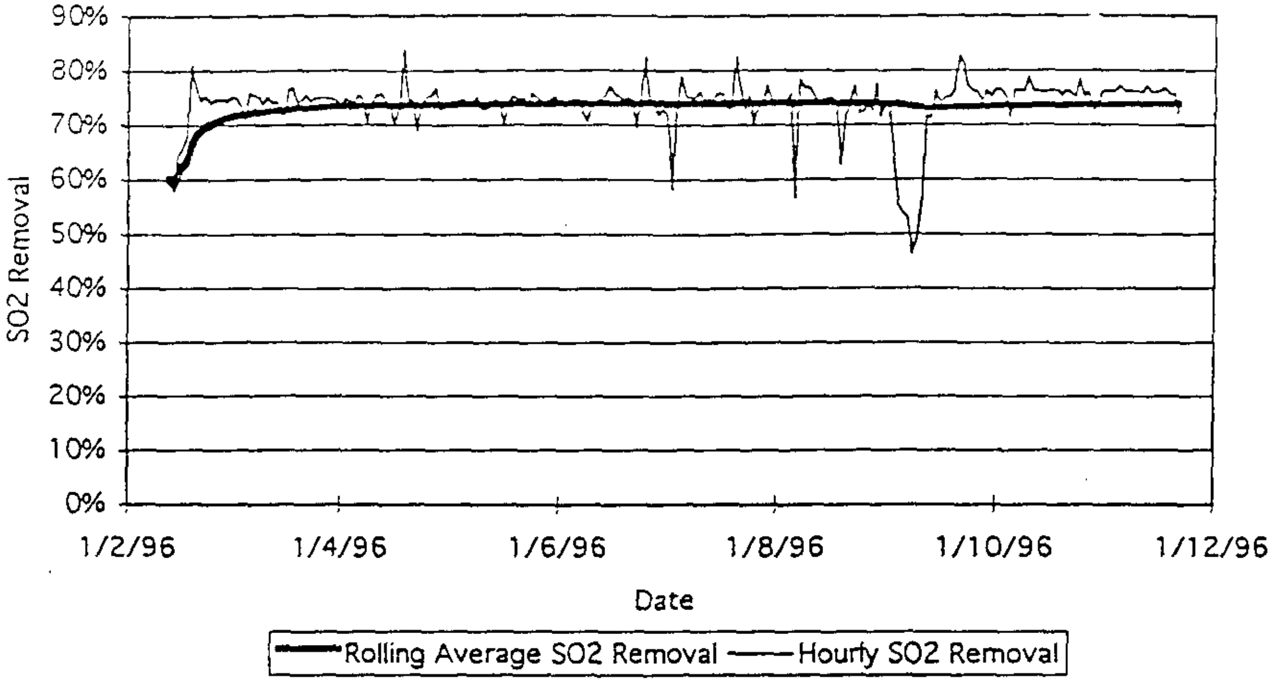
Throughout the long-term test, with a 40% set point, the rolling average SO_2 removal was easily maintained at, or above, 40 percent. However, there were brief periods when the DSI system was off-line due to line plugging or system maintenance. The NO_2 emissions during the long-term test increased sharply after each cleaning cycle, and then slowly decreased until the next cleaning cycle. Although the NO_2 emissions were variable, they were generally less than 10 ppm, and averaged 6.7 ppm for the 4 month test duration.

Following the four month test with a 40 percent set point, the set point was increased to 70% SO_2 removal and the system was operated for an additional one month period. Due to equipment problems during the DSI test period, the rolling average SO_2 removal was 67.9 percent, just short of the 70% goal. During this one month period, the NO_2 emissions averaged 15 ppm and a plume was visible on some occasions. NO_2 emissions tended to be highest and the visible plume was more prevalent during extended periods of low load operation.

Figure 4-13 shows the hourly averages of SO_2 removal and NO_2 emissions for a second ten day long-term test with a 70% SO_2 removal set point. The rolling average SO_2 removal for this period was 74 percent. While the NO_2 emissions varied over the range from 0-30 ppm, the average for the ten day test period was 12 ppm.

4.5.3 Sodium Bicarbonate Results

The sodium bicarbonate tests were performed ahead of the FFDC, at the same location utilized for the sodium sesquicarbonate tests. In addition, a series of tests were also run with a second set of injectors located ahead of the air heater.



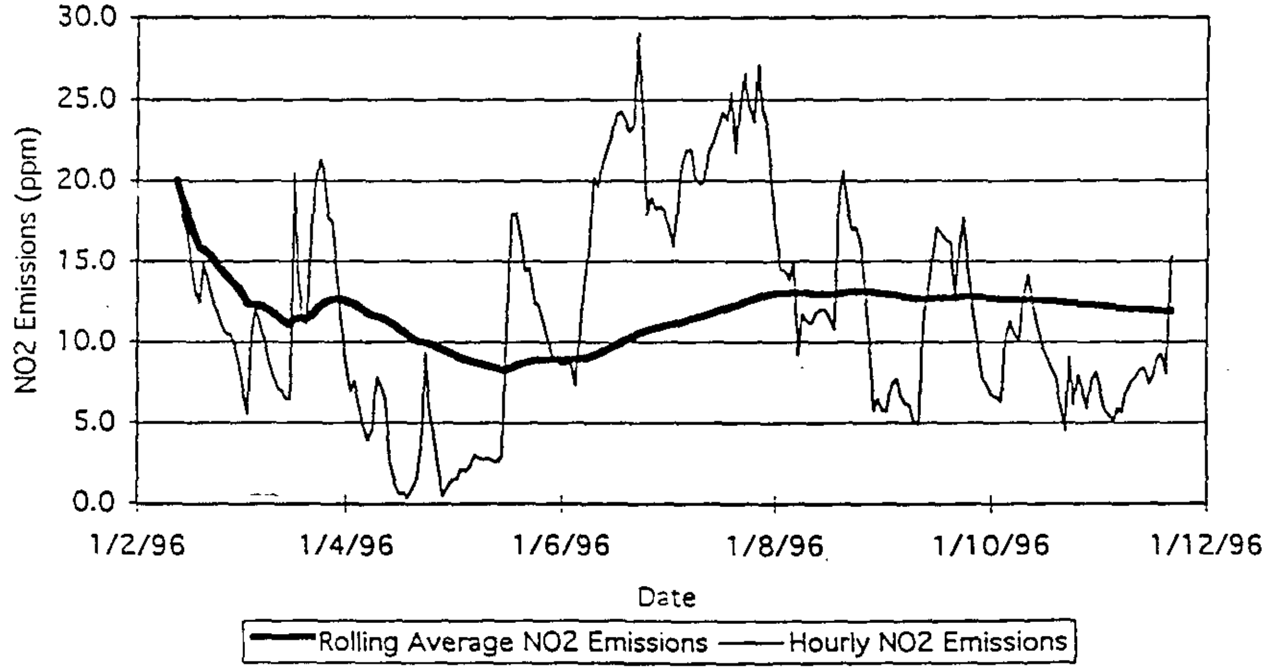


Figure 4-13. Long-Term Test Results with Sodium Sesquicarbonate Injection (SO_2 Removal Set Point at 70%)

4.5.3.1 *Injection of Sodium Bicarbonate at the FFDC Inlet*

With sodium bicarbonate injection ahead of the FFDC, nearly nine hours were required for the SO_2 removal to reach 50 percent, and the removals had still not reached a steady-state level. Flue gas temperatures entering and exiting the FFDC slowly climbed throughout the day but the exit gas temperature never exceeded 285°F. The slowly increasing trend in SO_2 removal was likely due to a combination of the slow increase in FFDC temperature and the accumulation of unreacted sodium on the bags.

The FFDC exit temperature at Arapahoe Unit 4 normally ranges from 230 to 270°F, and seldom reaches 290°F. A key step in the sodium process is the endothermic decomposition of sodium bicarbonate. At temperatures below 300°F, the decomposition reaction becomes very slow. In order to better understand the dynamics of the SO_2 removal process at these lower temperatures, the DSI system was run 24 hours a day for a period of five days. The sorbent injection rate was manually controlled to maintain a 2Na/S ratio of 1.0. The results show that the SO_2 removals drop dramatically after each FFDC cleaning cycle. However, after the FFDC had been "conditioned" through a few cleaning cycles, the SO_2 removals often reached a relatively steady state level after only a couple of hours. At a nominal 2Na/S ratio of 1.0, SO_2 removals ranged from 65 to 85 percent. The sorbent utilizations computed for the data from the series of tests also range from 65 to 85 percent.

During this test, gas measurements were made at the exit of each FFDC compartment in order to characterize the distribution of sorbent in the FFDC. The results of the compartment-by-compartment measurements showed high levels of SO_2 removal (80 to 90 percent) in the first three compartments on each side of the FFDC. This was followed by a rapid decrease down to levels of only 10 to 20 percent in the rear compartments. As with the sodium sesquicarbonate, the majority of the sorbent is deposited in the front half of the FFDC.

The average NO_x removal for the five day test was 10 percent with no discernible correlation with either FFDC cleaning cycle or temperature. The NO_2 emissions also varied widely during the test, ranging from 6 to 33 ppm, with an average of 16 ppm. Two trends were observed in the NO_2 data. First, there was a sharp increase in NO_2 emissions after a FFDC cleaning cycle, followed by a slow decrease in emissions until the next cleaning. This again is attributed to an interaction between NO_2 and the carbon in the fly ash on the bags. Secondly, the data indicate that there was a general increasing trend in NO_2 emissions throughout the duration of the five-day test. No explanation can be offered for this observation.

Overall, these test results indicated that the FFDC temperature was too low to effectively utilize sodium bicarbonate when injected ahead of the FFDC at Arapahoe Unit 4.

4.5.3.2 Sodium Bicarbonate Injection at the Air Heater Inlet

Reduced reactivity of sodium bicarbonate at low FFDC temperatures, can be compensated for by injecting at higher temperatures, such as at the air heater inlet (Muzio, et al., 1984). Four injectors were installed in the top of the duct between the economizer and air heater. SO_2 removals measured at both the FFDC inlet and stack showed that the SO_2 removal response time improved over injection at the FFDC inlet. The initial response time was reduced to approximately 1-1/2 hours, and the recovery time after a cleaning cycle was reduced to less than 30 minutes. The more rapid decomposition of sodium bicarbonate at the higher air heater inlet temperatures was likely responsible for the temperature sensitivity.

Figures 4-14 and 4-15 show the effect of 2Na/S ratio on SO_2 removal and sorbent utilization for injection ahead of the air heater. Data for both the 4000 and 5000 rpm pulverizer speeds show that at 2Na/S ratios up to approximately 1.0, pulverizer speed has little effect on SO_2 removal. However, at 2Na/S ratios in excess of 1.5, the SO_2 removals at 5000 rpm continue to increase, while the 4000 rpm data begins to level out. As the sorbent loading increases, the 4000 rpm speed cannot process the material and the particle size increases, resulting in SO_2 removal decreases.

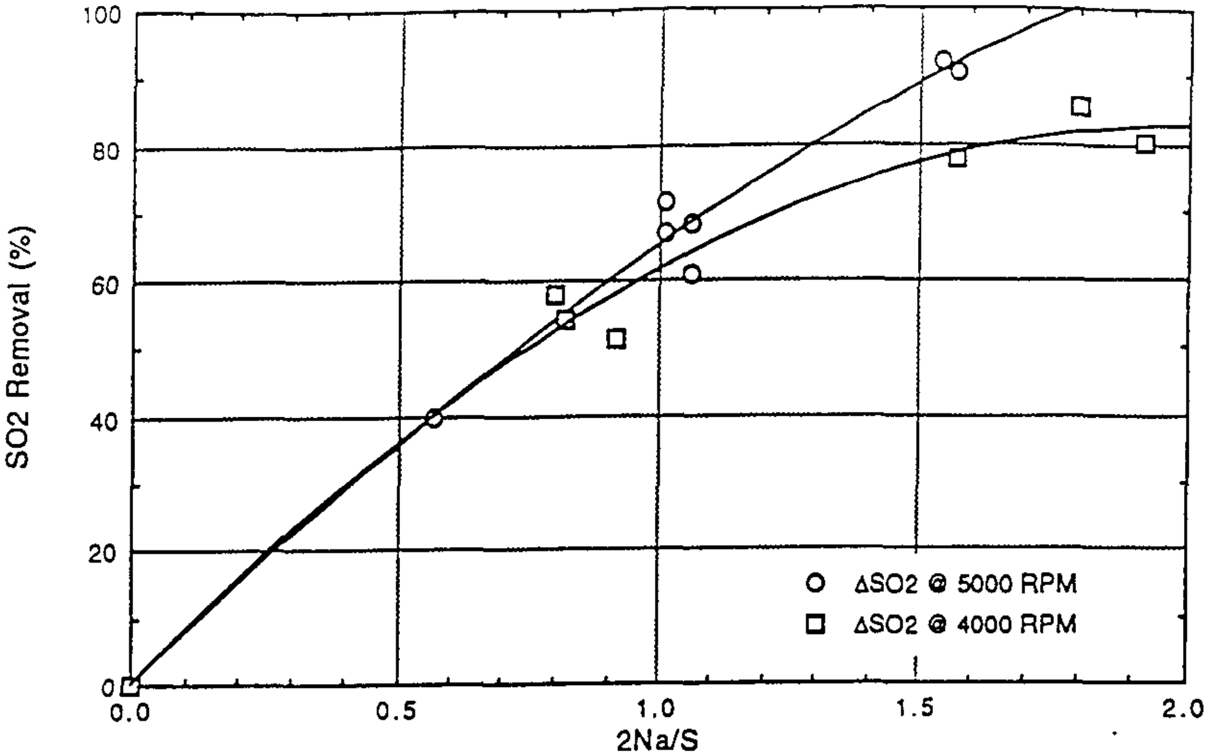


Figure 4-14. Utilization as a Function of 2Na/S Ratio for Sodium Bicarbonate Injection Ahead of the Air Heater

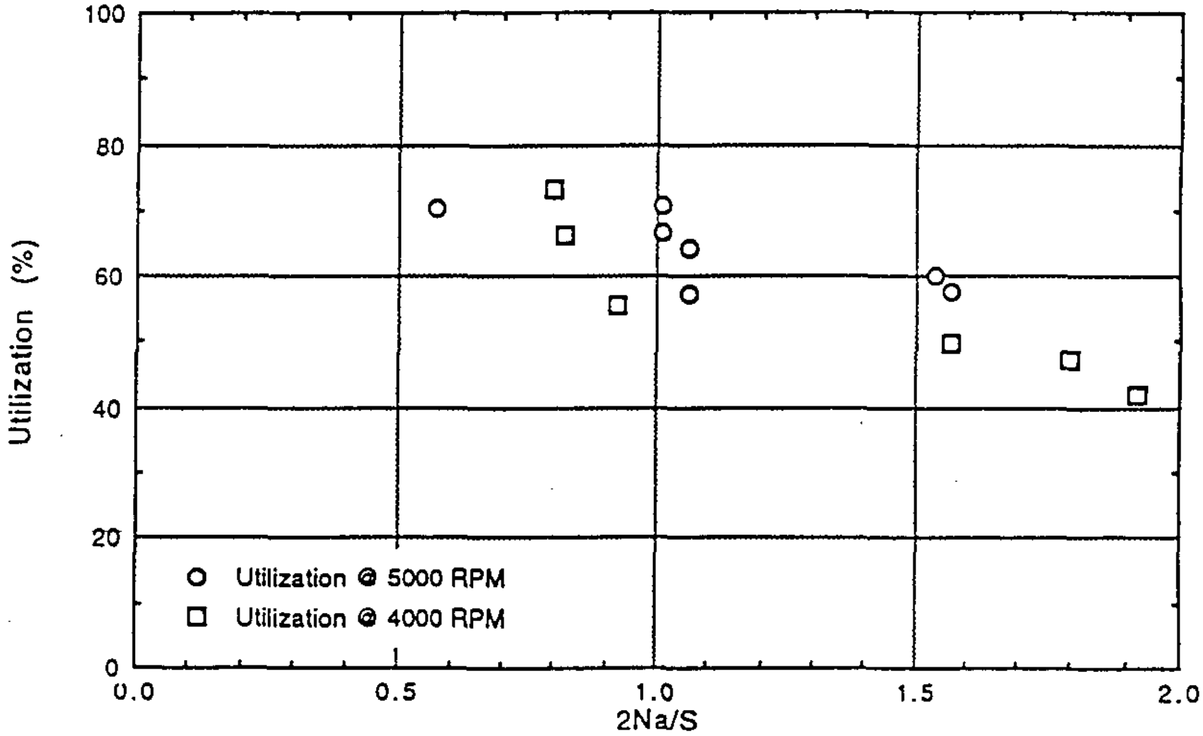
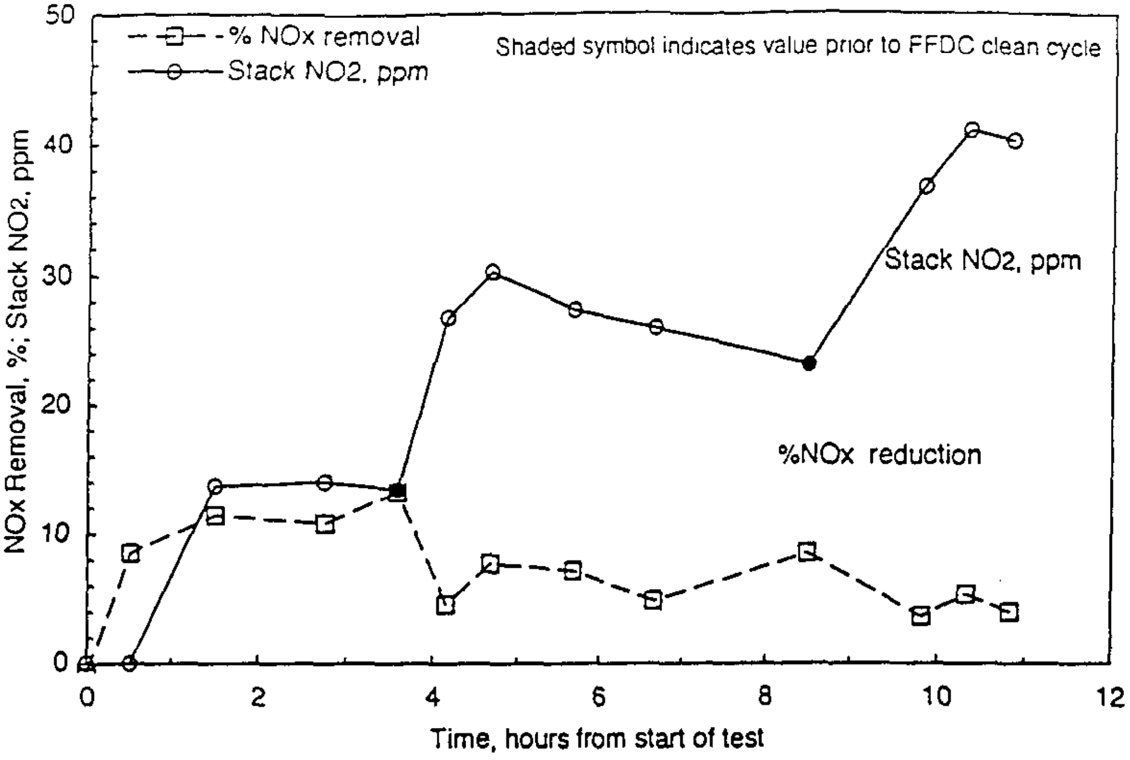


Figure 4-15. Utilization as a Function of 2Na/S Ratio for Sodium Bicarbonate Injection Ahead of the Air Heater

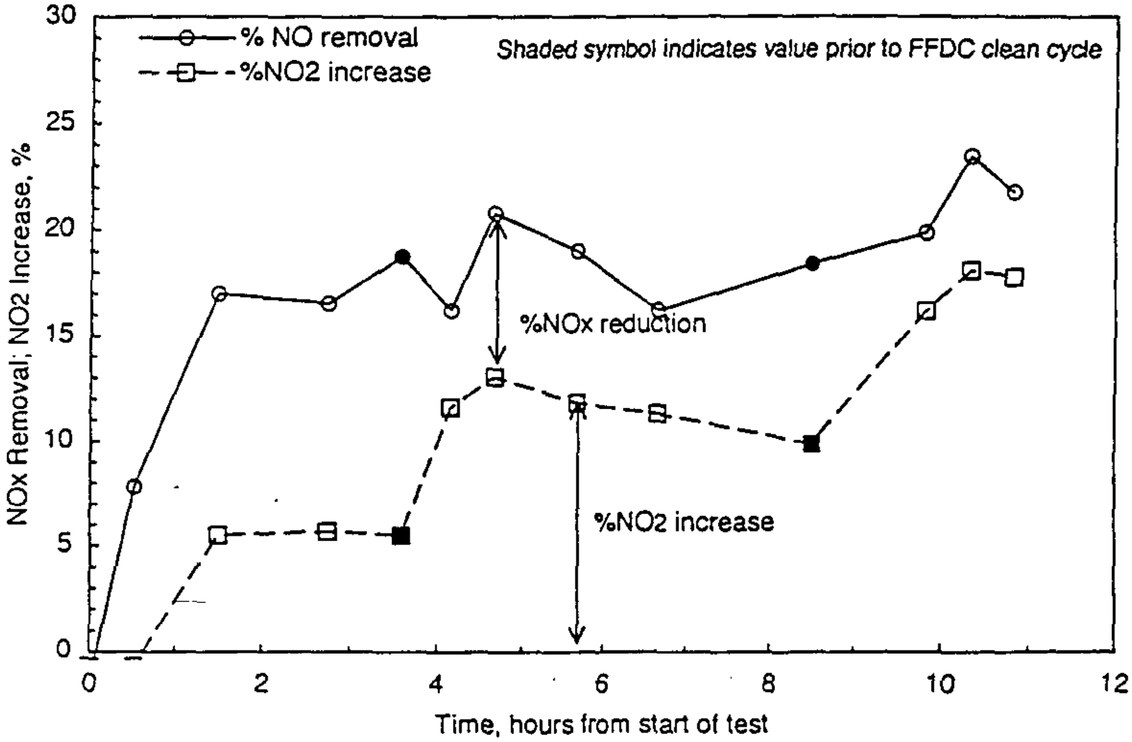
The 5000 rpm SO_2 removals for injection at the FFDC inlet are slightly higher than those for injection ahead of the air heater (approximately 75 percent versus 66 percent at a 2Na/S ratio of 1.0). During bicarbonate decomposition, the evolution of H_2O and CO_2 creates a high surface area Na_2CO_3 particle. The decomposition reaction occurred quickly at the higher air heater inlet temperatures, and was likely complete by the time the sorbent reached the bags and the sulfation reaction occurred (i.e., the decomposition and sulfation took place in series). When the sorbent was injected at the inlet of the FFDC, the decomposition and sulfation reactions occurred simultaneously.

The compartment-by-compartment gaseous emission measurements for sodium bicarbonate injection ahead of the air heater was similar to that seen for injection at the FFDC inlet, indicating that the majority of the sorbent is deposited in the forward compartments.

Figure 4-16(a) shows the NO_x removal and NO_2 emission traces for an 11 hour bicarbonate injection test at the air heater inlet. The NO_2 emissions increase after each cleaning cycle, however, the NO_2 levels were decreased slightly between cleaning cycles. On the average, the NO_2 emission level continued to increase throughout the duration of the test. The average NO_x removal for the entire test was 8 percent, but the removals decrease with time in accordance with the increases in NO_2 emissions. Figure 4-16(b) shows the partitioning of the reacted NO between NO_x reduction and NO_2 formation. Early in the test, the majority of the NO that reacted resulted in NO_x reduction, rather than NO_2 emissions. As the test proceeded through two cleaning cycles this trend changed. While there was a continued increase in the overall amount of NO that reacted (17% after 1 1/2 hours up to 23% after 10 hours), NO_x reduction decreased and the majority of the NO that reacted showed up as NO_2 emissions. This is different than the test reported previously for sodium sesquicarbonate (Figure 4-8(b)). It is not clear if these differences are due to the differences in the two sorbents or differences in the ash characteristics on the bags for the two tests.



(a) NO_2, ppm; ΔNO_x Percent



(b) Partitioning of ΔNO between NO_2 and ΔNO_x

Figure 4-16. NO_x Removal and NO_2 emissions versus Time for Sodium Bicarbonate Injection Ahead of the Air Heater

The NO_2 emissions for all of the sodium bicarbonate tests at both injection locations (ahead of the FFDC and ahead of the air heater) are summarized in Figure 4-17. Again, the scatter in the data is attributable to the dependence of NO_2 emissions not only on the amount of sodium injected, but also on the fly ash and FFDC cleaning cycle. As seen with sodium sesquicarbonate, there is no clear difference in the amount of NO_2 produced at each injection location. The data in the 2Na/S range of 0.9 to 1.1 have been replotted in Figure 4-18 as a function of the time from the end of a FFDC cleaning cycle. This presentation of the data shows that the large variations in NO_2 shown in Figure 4-16 occur just after a cleaning cycle. At longer time periods after a cleaning cycle, the NO_2 levels trend toward a steady-state level of 10-20 ppm.

4.5.3.3 Sodium Bicarbonate Injection NO_x Removals

The NO_x removals with sodium bicarbonate are summarized in Figure 4-19 for both injection ahead of the FFDC and ahead of the air heater. Again, a fair amount of scatter in the data is seen, which is attributed to the process dynamics. Overall NO_x removal at a nominal 2Na/S ratio of 1.0 ranged from 0 to 20 percent, and averaged approximately 10 percent

4.6 Environmental Performance of Sodium-Based DSI

4.6.1 Sodium-Based DSI

This section briefly summarizes the results of the environmental monitoring performed during the testing of the sodium-based DSI system. The environmental monitoring was completed according to the *Environmental Monitoring Plan for the Integrated Dry* NO_x/SO_2 *Emissions Control System*, dated February 1992 and the *Environmental Monitoring Plan Addendum for Air Toxics*, dated July 1993.

Generally, the testing went well and there were no significant environmental events during the testing of the sodium-based DSI system. Except for opacity, there were no excursions of any compliance monitoring. Opacity was in compliance 99.92% during the

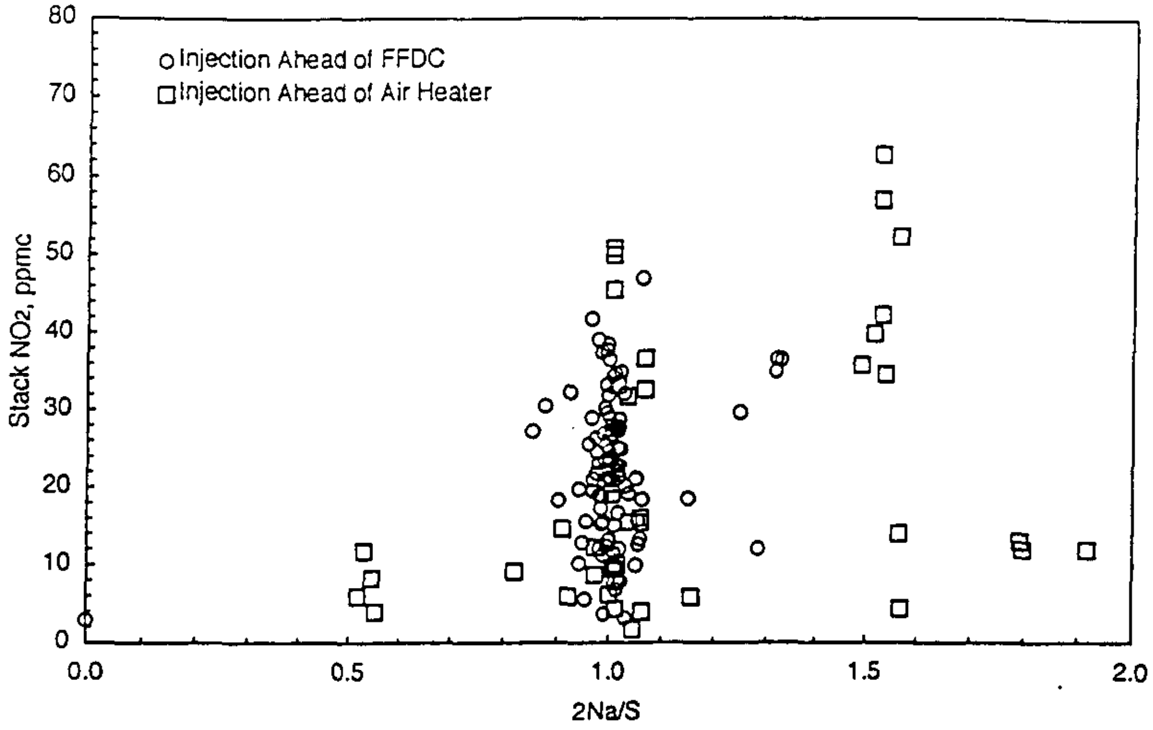


Figure 4-17. Summary of NO_2 Emissions with Sodium Bicarbonate Injection

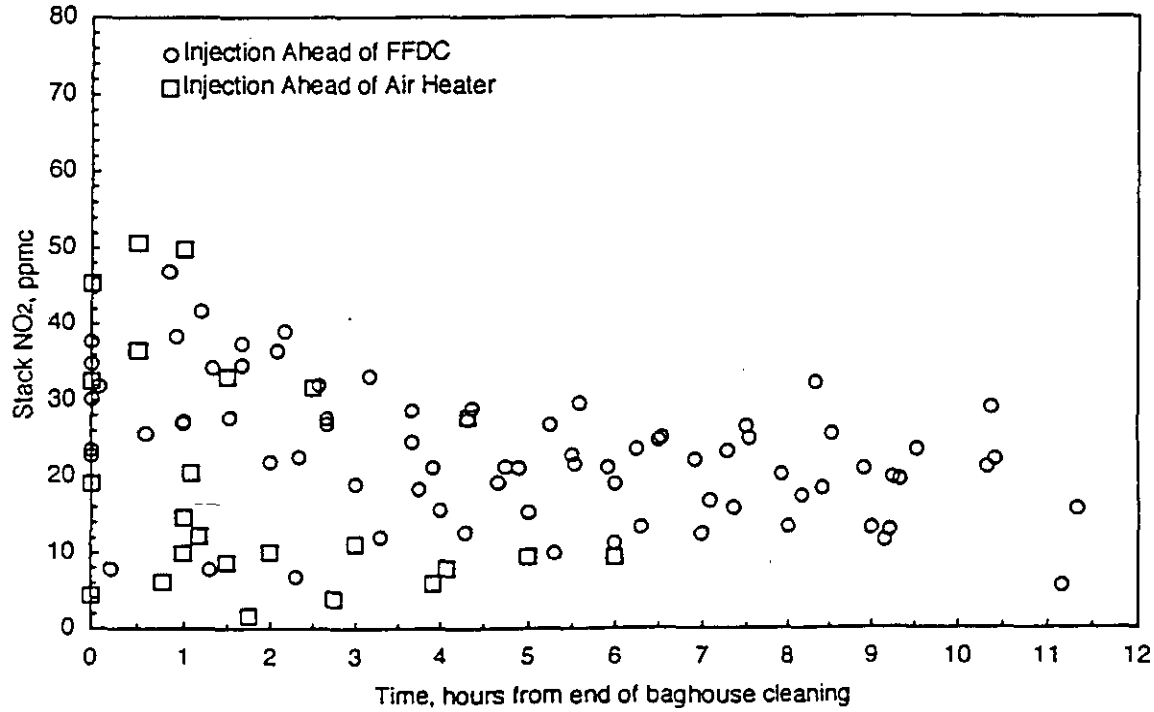


Figure 4-18. NO_2 emissions and FFDC Cleaning with Sodium Bicarbonate (2Na/S 0.9 to 1.1)

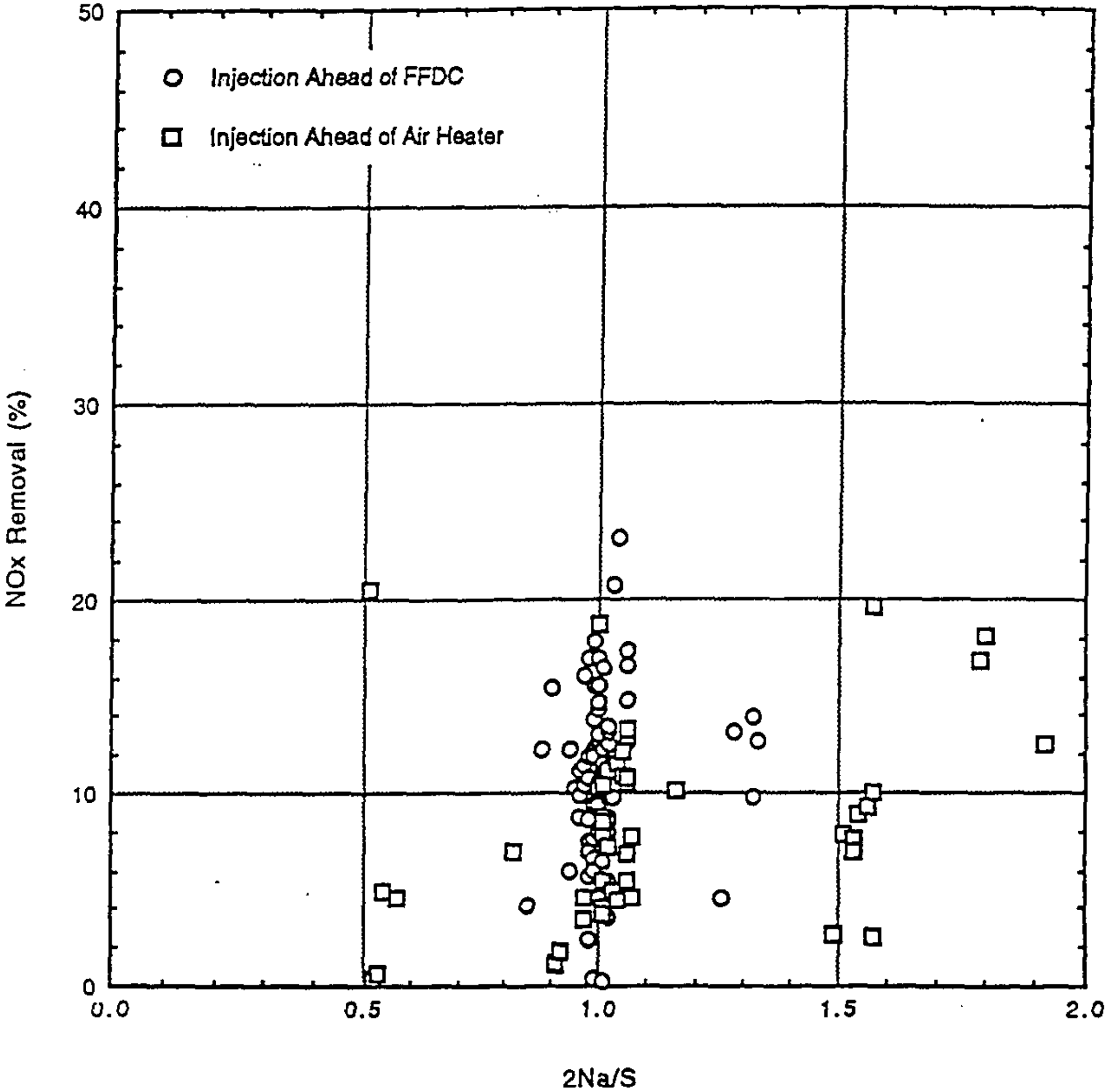


Figure 4-19. NO_2 emissions and FFDC Cleaning with Sodium Bicarbonate (2Na/S 0.9 to 1.1)

test period and none of the opacity excursions that occurred during the testing were related to the sodium-based DSI system. The average opacity ranged from 3 to 8%.

A significant amount of supplemental monitoring was conducted to determine the emissions while operating and testing the DSI system with sodium-based reagents. The major effect was the benefit of reduced SO_2 emissions. Additional supplemental monitoring to collect 21 potential air toxics was completed during the sodium-based testing. Sampling for this testing was conducted October 15-16, 1993. Trace metals removal was similar to other test program and greater than 97.2%. The only major difference during the sodium injection air toxics testing was a large increase in the fluoride reduction. Details of the air toxics test program and a comparison of all four air toxics tests are contained in Appendix D.

4.6.2 Summary of WRI Report

The Western Research Institute (WRI) was contracted to investigate the potential impact of Clean Coal Technology (CCT) fly ash waste materials (sodium injection, calcium injection, and urea injection with low NO_x burners) on the permeability and stability characteristics of clay liner materials and the stability of synthetic liner materials. Tests were conducted using the waste materials overlying clay liner and synthetic liner materials under wet/dry cycles, freeze/thaw cycles and over 120-day periods.

The impact of CCT materials on the characteristics of clay liner materials studied in this project was minimal. The hydraulic conductivity (HC) measurements of the waste/clay liner systems were similar to the water/clay liner systems. HC decreased for clay liners compacted at moisture levels slightly higher than optimum (standard Proctor) and increased for liners compacted at moisture levels lower than optimum (standard Proctor). Although some swelling was evident in the sodium injection materials, these materials did not have a negative impact on the integrity of the liners over 120-day tests. Wet/dry cycles tended to result in lower HC values, while freeze/thaw cycles substantially increased HC for the liners tested.

Sustained increment changes in the measured physical properties of the synthetic materials over time were not observed. Some abrupt changes in strength were found at several times during the testing period. However, these aberrations seemed more indicative of isolated changes in the conditioning methods or test procedures and could be related to flaws or changes in the materials due to manufacturing conditions. After 120 days of conditioning, none of the measured physical properties varied significantly form those for the untreated liner materials. This was true for all samples regardless of the conditioning solution used. It is apparent from the results of this study, that the high-density polyethylene (HDPE) liner material would be expected to perform better than the very low-density polyethylene (VDPE) and polyvinyl chloride (PVC) liner materials due to its higher strength characteristics.

The volatiles and extractables tests for the HDPE and VDPE materials indicated that the waste materials had little influence on their overall structure. However, the extractables data suggest that PVC liner material might decompose in the waste environments evaluated. The PVC liner material reacted similarly for all treatments with about a 30% weight loss.

A complete copy of the report *The Impact of Leachate From Clean Coal Technology Waste on the Stability of Clay Liners and Synthetic Liners* can be found in Appendix E.

4.7 Bench Scale DSI

4.7.1 Objectives

As part of the project, a fundamental study of the SO_2/NO_x chemistry was conducted by the Colorado School of Mines by Professor Victor F. Yesavage and Mr. Yi-chi Lai. The objectives of this fundamental bench scale study were as follows:

- Develop overall reaction rate data for the reaction between sodium bicarbonate, sodium sesquicarbonate and SO2.

- Develop a better understanding of the detailed chemistry between SO2, NOx and the sodium compounds in terms of reaction paths leading to the formation of NO2 and the removal of NOx by sodium.

A detailed description of the bench scale work is contained in the report documenting the sodium injection test results (Smith, et al., 1997). The complete report is contained in Appendix F.

4.7.2 Methodology

To address the objectives of this activity, a bench scale study was conducted at the Colorado School of Mines. This study included a series of time resolved batch experiments in a batch-fed reactor supported by chemical kinetic modeling.

To address the first objective, the time rate of change of SO_2 in the reactor was monitored as a function of the type of sodium sorbent, amount of sodium sorbent and temperature.

To address the second objective, tests were designed to help distinguish the mechanisms leading to NO_2 formation. Two different mechanisms have been proposed for the production of NO_2 during the sodium/SO_2 reactions. One was developed by work supported by EPRI (EPRI, 1990) and the other is work done by Solvay (Verlaeten, et al., 1993). The mechanisms shown below are for sodium bicarbonate, although parallel mechanisms could be written for sodium sesquicarbonate.

4.7.2.1 EPRI Mechanism

Sodium Bicarbonate Decomposition

$$2NaHCO_3 \rightarrow Na_2CO_3 + CO_2 + H_2O \tag{1}$$

SO2 Removal

$$Na_2CO_3 + SO_2 + 1/2O_2 \rightarrow Na_2SO_4 + CO_2 \tag{2}$$

NO Removal and NO2 Formation

$$NO + 1/2\ O_2 \xrightarrow{Na\ /\ SO_2} NO_2 \tag{3}$$

$$Na_2CO_3 + 3NO_2 \rightarrow 2NaNO_3\ NO + CO_2 \tag{4}$$

The EPRI mechanism proposes sodium carbonate (Na_2CO_3) as the primary reactant leading to SO_2 removal. NO_2 is proposed to form via reaction (3) along with some undetermined intermediate steps. NO_x removal then occurs by a reaction between sodium carbonate and NO_2 forming sodium nitrate, reaction (4).

4.7.2.2 Solvay Mechanism

The Solvay mechanism incorporates a direct reaction between the undecomposed sodium materials and SO_2.

SO2 Removal

$$NaHCO_3 + SO_2 \rightarrow NaHSO_3 + CO_2 \tag{5}$$

$$2NaHSO_3 \rightarrow Na_2S_2O_5 + H_2O \tag{6}$$

With the sodium sulfite ($NaHCO_3$) and sodium pyrosulfite ($Na_2S_2O_5$) intermediates, Solvay has an alternate interpretation of the NO_x removal that involves the intermediate sodium pyrosulfite compound.

NO Removal

$$Na_2S_2O_5 + 2NO + O_2 \rightarrow NaNO_2 + NaNO_3 + 2SO_2 \tag{7}$$

$$2NaHSO_3 + 2NO + O_2 \rightarrow NaNO_2 + NaNO_3 + 2SO_2 + 2H_2O \tag{8}$$

In the Solvay mechanism the NO_2 would be formed by decomposition of one of the products from reaction (7) and/or (8). Tests in the batch feed reactor investigated NO_2 formation using sodium sulfite and sodium pyrosulfite as reactants. Chemical kinetic modeling was also used to evaluate the mechanism.

4.7.3 Instrumentation

The experiments were conducted in a bench-scale batch-fed reactor. The apparatus consists of SO_2 and NO feed systems, a neutralization bottle containing 1M NaOH solution designed for trapping SO_2 and NO_x acid gases, a system for feeding background gas containing 3% oxygen and 97% nitrogen, a batch reactor with a heating control unit, and a gas analysis system.

A schematic of the bench-scale system is shown in Figure 4-20. The basic components are a 12,864 ml batch reactor which contains the reaction mixtures, the dry sorbent, a heating control unit which keeps the reaction temperature constant between 200 to 570°F, and a propeller-type mixer designed to eliminate temperature and mass transfer gradients surrounding the dry sorbent particles.

The batch reactor is made of stainless steel with four fittings on the top cover. The first fitting is a control valve utilized for either gas or sorbent powder injection. The second fitting is a control valve, used for draining the unreacted acid gases to a neutralization bottle containing a 1M NaOH solution. The third fitting is a sampling port swagelock fitting, equipped with a 9 millimeter diameter septum. The fourth fitting is an injection port with a septum, which is identical to the sampling port. Both, sampling and injection ports, are used for withdrawing the reacting gas mixtures and for injecting acid gases, SO_2 and NO.

A stirring motor is used to drive a propeller type mixing device with a variable speed ranging from 0 to 700 rpm. A Teflon-type Conax seal is used to seal the rotating rod at ambient pressure in the reactor.

The major components in the heating control unit are a 1800 watt Watlow mica band heater, and an Omega Series 920 temperature controller.

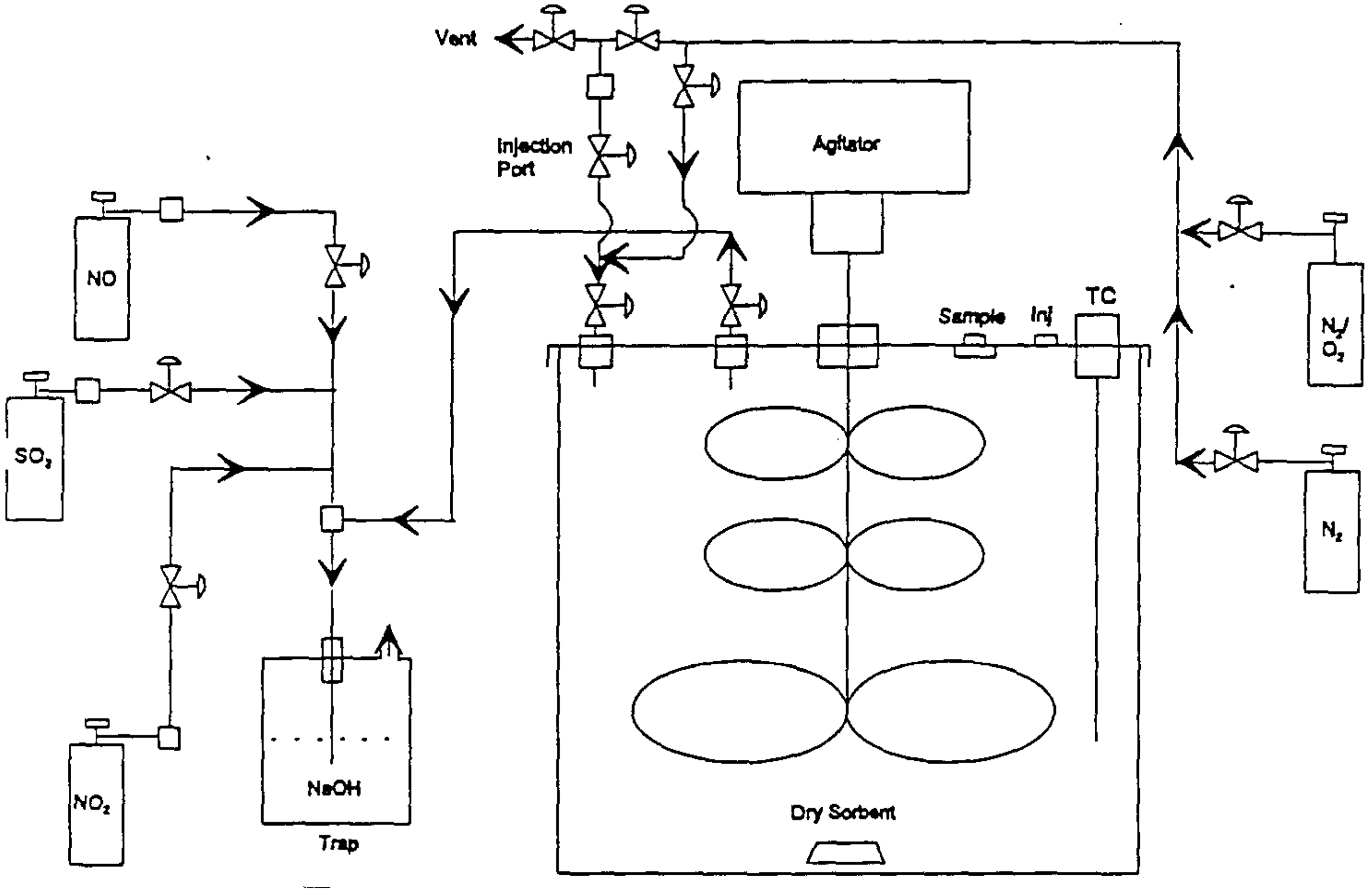


Figure 4-20. Dry Sorbent Scrubber System Bench Scale Apparatus

Analytical techniques include the analysis of syringe samples for SO_2, NO_x and NO. SO_2 was measured using a Hewlett Packard model 5890 gas chromatograph equipped with a thermal conductivity detector, and a 8' x 1/4" Supelco Porapak Q glass column with particle size 80/100 at a temperature of 70°C. NO and NO_x was analyzed using a chemiluminescent analyzer.

4.7.4 Test Methods

Two basic types of experiments were conducted during the study. The first group of experiments were conducted to develop overall reaction rate data for SO_2 reactions with sodium bicarbonate and sodium sesquicarbonate. These experiments were conducted with the following range of parameters:

– Sodium Sorbents :	– sodium bicarbonate, sodium sesquicarbonate
– Particle Size :	– 53 μm < d < 63 μm
– NSR :	– 0 , 0.85, 3.4, 13.5
– Temperature :	– 260°F, 300°F
– so2 :	– 1800 ppm
– NO :	– 1800 ppm
– H_2O, O_2 :	– 5%, 3%, (balance N_2)
– Reaction Times :	– 0 - 30 minutes

During these tests, time resolved histories of SO_2, NO, and NO_x were measured.

The next group of experiments sought to provide a better understanding of the detailed chemistry between SO_2, NO_x and the sodium compounds. These latter experiments involved varying the water content of the gas; as well as studying the reaction of potential intermediate compounds (i.e., $NaHSO_3$ and $Na_2S_2O_5$) with SO_2 and NO_x.

4.7.5 Quality Assurance

Quality assurance for this activity involved ensuring that the sorbents used for the experiments were of high quality and that the experimental measurements from the batch reactor were providing valid concentrations.

All sorbents were reagent grade chemicals with purities of greater than 99%; the exception being the sodium pyrosulfite that had a purity of 97%. The materials were ground with a mortar, sieved and stoned in a desiccated container.

Initially, the NO_x measurements were to be performed with a gas chromatograph along with the SO_2 determinations. This was not successful and a chemiluminescent NO-NO_x analyzer (TECo Model 44) was used to measure NO_x. The chemiluminescent analyzer is normally used in a continuous sampling mode. For this study, a technique was developed and validated to use the chemiluminescent analyzer to analyze batch syringe samples taken from the batch reactor.

Also, during the course of the study, it was shown that this gas chromatographic procedure lead to errors in the SO_2 concentration due to the presence of NO_x in the reaction mixture. This effect was thought to be due to a reaction sequence that forms N_2O (Muzio, et al., 1988). To eliminate the effect, it was necessary to perform the SO_2 analysis immediately upon obtaining a sample.

4.7.6 Results

In this section, the basic experimental results with sodium bicarbonate and sodium sesquicarbonate will be presented. This will be followed by a discussion of the results of the experiments addressing the detailed chemistry.

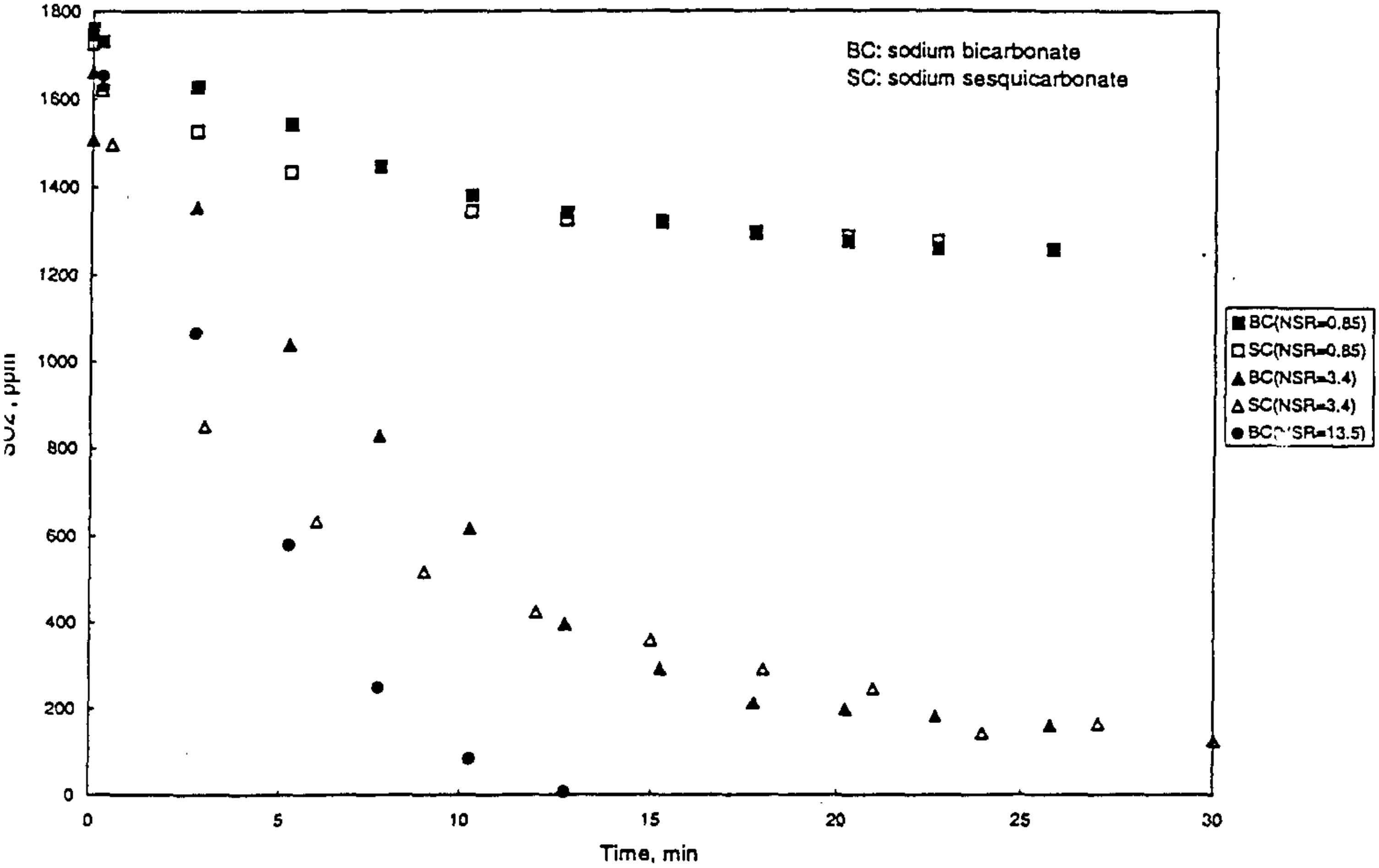


Figure 4-21. SO_2 Time Histories in the Bench Scale Apparatus

4.7.6.1 Overall Reaction Rates

The SO_2 time histories for both sodium bicarbonate and sodium sesquicarbonate are shown in Figure 4-21. As expected, SO_2 removals increase with increasing stoichiometric ratios (2Na/S) for both sorbents. The short time data (i.e., less than 5 minutes) are consistent with the full-scale data in that the sesquicarbonate reacts faster than the bicarbonate. At 2Na/S ratios of 0.85 and 3.4, the overall level of SO_2 removal is similar for both sorbents. This is quite surprising, particularly at the lower value of 0.85. The current full-scale tests at Arapahoe Unit 4, as well as previous full-scale demonstrations (Fuchs, et al., 1989; Muzio, et al., 1984) show that sodium bicarbonate will yield higher overall SO_2 removal than sodium sesquicarbonate for a given amount of sodium. This may have been the case had the experiments shown in Figure 4-21 been extended to longer time periods.

The NO_2 production as a function of reaction time is shown in Figure 4-22 for both sodium bicarbonate (2Na/S=0.85, 3.4, and 13.5) and sodium sesquicarbonate (2Na/S=0.85, and 3.4). For both sorbents, there does not appear to be a strong effect of stoichiometric ratio on the amount of NO_2 produced, as the scatter in the data is as great as any perceptible 2Na/S effect. The NO_2 results do indicate that sodium bicarbonate (solid symbols) tends to produce higher levels of NO_2 than sodium sesquibicarbonate (open symbols) which is consistent with the full-scale test results at Arapahoe Unit 4. With sodium sesquicarbonate the NO_2 levels were generally 200 ppm (11% of the initial NO levels).

The time histories of NO_x removal are shown in Figure 4-23 for both sodium bicarbonate and sodium sesquicarbonate. The open symbols are data for sodium bicarbonate and the solid symbols for sodium sesquicarbonate. For both sorbents, the level of NO_x removal increases with increasing stoichiometric ratio. At 2Na/S ratios of 0.85 and 3.4, the ultimate level of NO_x removal was similar for both sorbents. Although consistent with the initially higher reaction rate of sodium sesquicarbonate, the rate of NO_x removal with

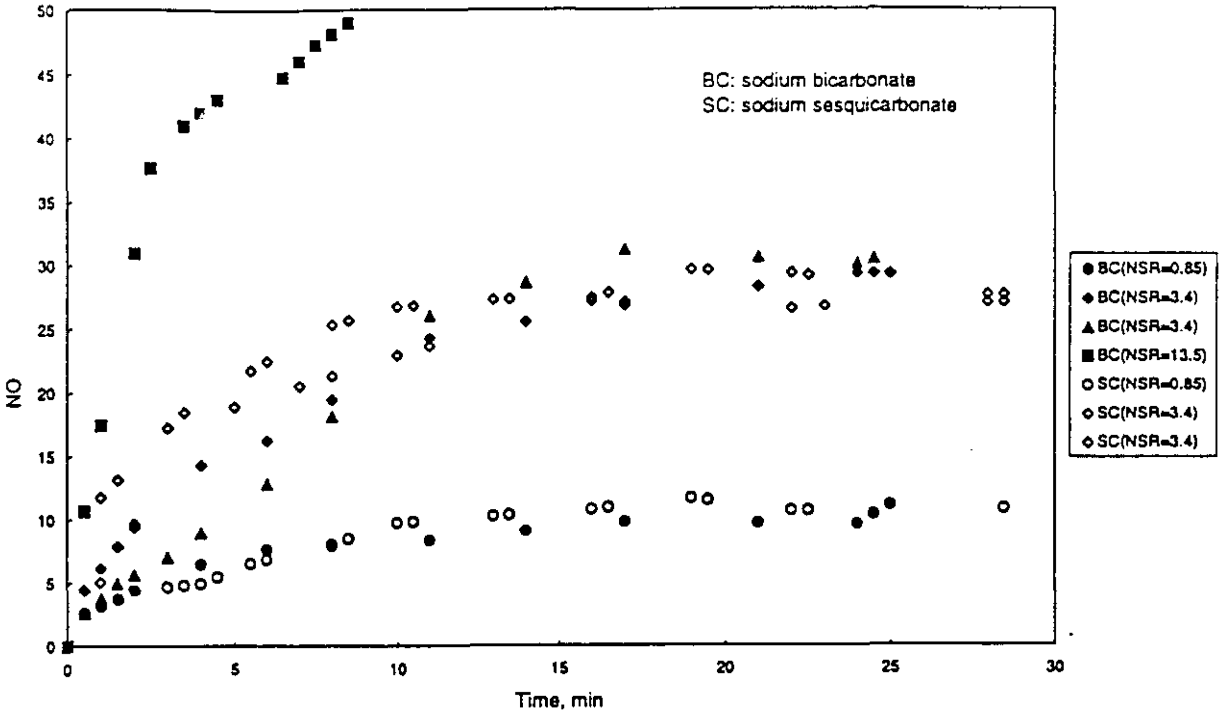


Figure 4-22. NO_2 Time Histories in the Bench Scale Apparatus

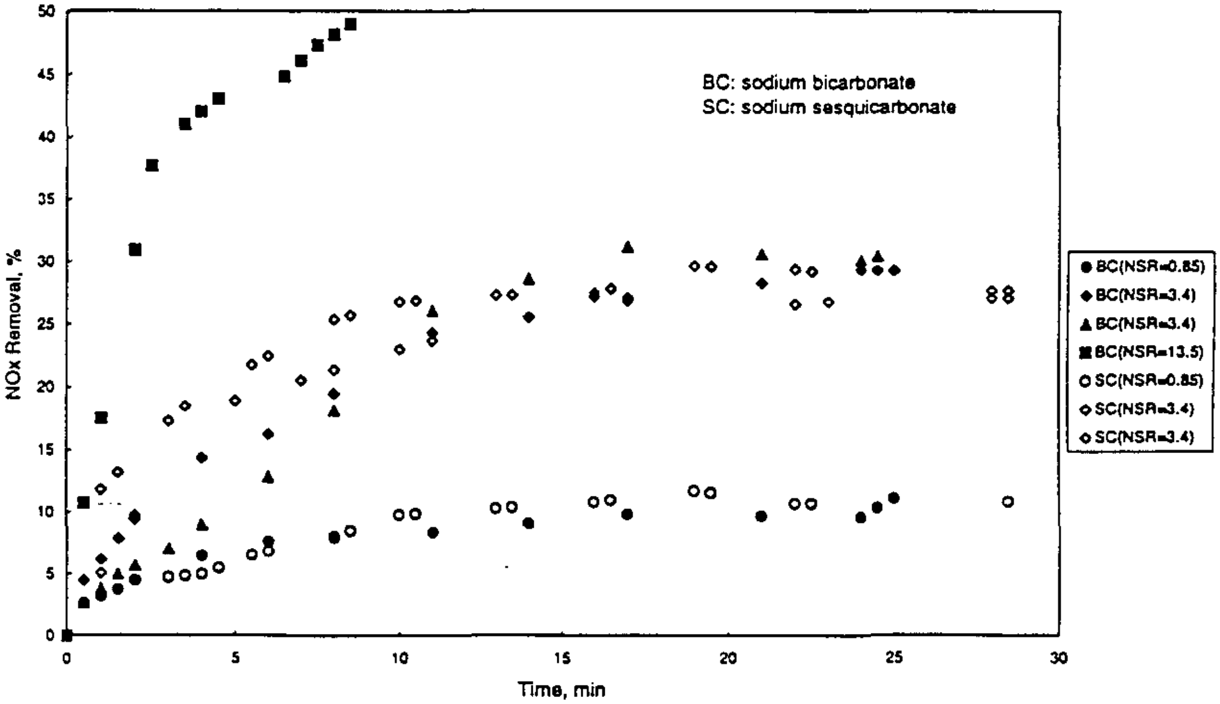


Figure 4-23. NO_x Removal in the Bench Scale Apparatus

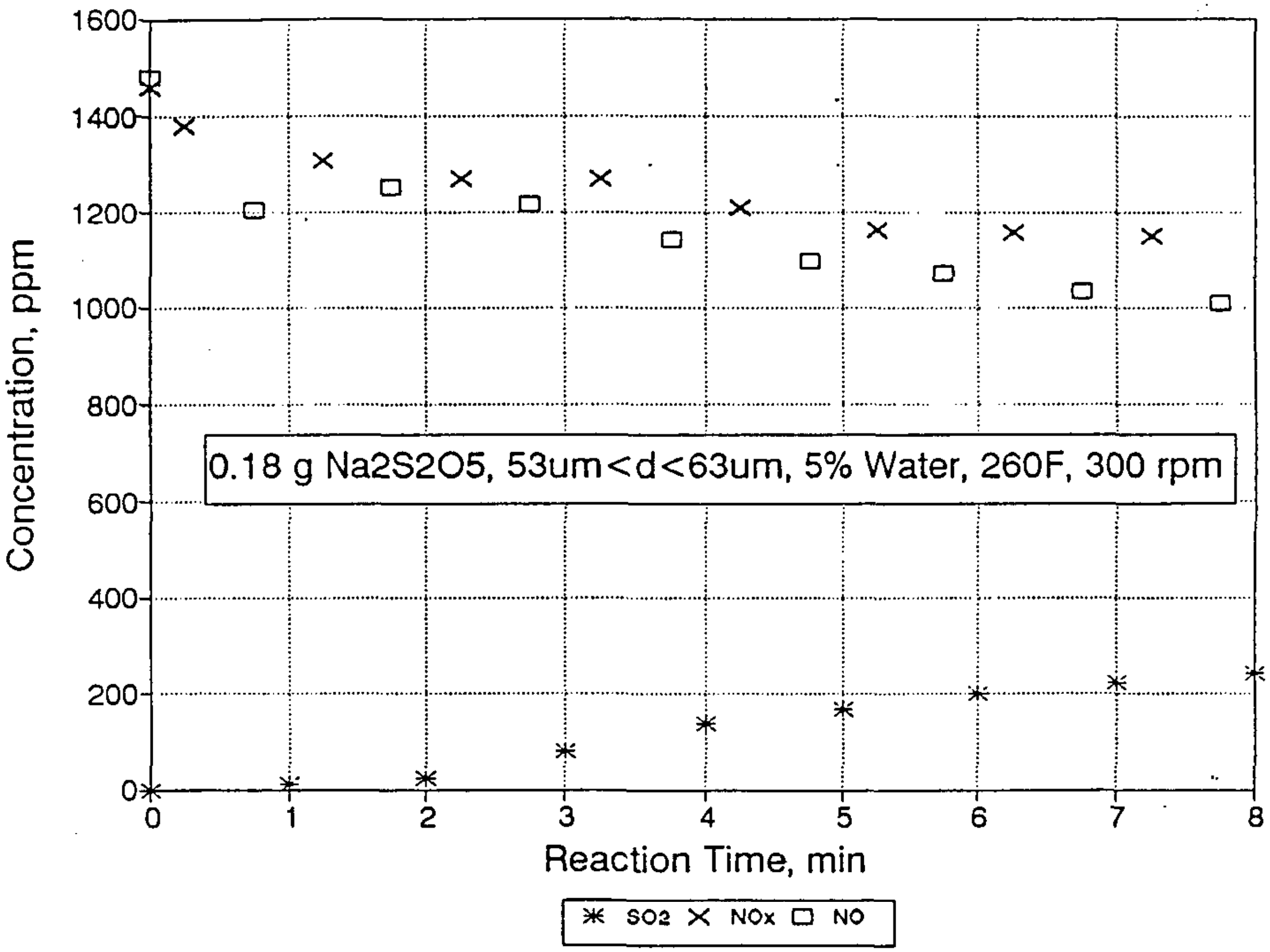


Figure 4-24. NOx Removal By Sodium Pyrosulfite

sodium sesquicarbonate at 2Na/S=3.4 was faster than for sodium bicarbonate. The overall NO_x removal of 10% at 2Na/S=0.85 is also consistent with the NO_x removals achieved at full scale.

The next group of tests were conducted to determine if the intermediate compounds proposed by Solvay (Verlaeten, et al., 1993); $NaHSO_3$ or $Na_2S_2O_5$ were important intermediates. Figure 4-24 shows the results of the reaction between 3000 ppm sodium pyrosulfite ($Na_2S_2O_5$) and a gas mixture of 1500 ppm NO, 3% O_2 and 5% H_2O at a temperature of 260°F. The results show that NO_x removal is about equal to the amount of SO_2 produced; consistent with reaction (7). This would suggest that sodium pyrosulfite may indeed be an intermediate in the removal of NO_x by sodium-based sorbents.

A comparable test was conducted with sodium sulfite ($NaHSO_3$) at a stoichiometric ratio of 2 (i.e., 4 moles of $NaHSO_3$ per mole of NO, per reaction (8)) and a temperature of 260°F. During this test, there was no production of SO_2 and the change in NO_x was minimal. This would suggest that while $NaHSO_3$ may be an intermediate in the chemical mechanism, *it is the formation of* NaS_2O_5 *from the* $NaHSO_3$ *(i.e., reaction (6)) that is* important, and not reaction (8) in terms of NO_x removal or NO_2 production.

4.7.6.2 Chemical Kinetic Modeling

Chemical kinetic modeling was used to evaluate the two detailed mechanisms discussed previously. A shrinking core model was used and the rate constants for the individual reactions were extracted from the bench-scale data. The modeling effort suggested that the sodium/SO_2/NO_x chemistry is better predicted using the Solvay mechanism.

The detailed Solvay mechanism was simplified assuming that the intermediate compounds ($Na_2S_2O_5$ and $NaHSO_3$) have short lifetimes. With this assumption, the shrinking core model of the Solvay mechanism reduces to the following set of equations.

$$\frac{d[SO_2]}{dt} = -S\,k_A\,[SO_2] \tag{9}$$

$$\frac{d[NO]}{dt} = -S\,k_B\,[SO_2][NO] \tag{10}$$

$$\frac{d[NO_2]}{dt} = -\frac{x}{2}\,S\,k_B\,[SO_2][NO] \tag{11}$$

$$\frac{dR}{dt} = -a\frac{M}{D}\left\{k_A\,[SO_2] + \frac{1}{2}\left(1-\frac{x}{2}\right)k_B\,[SO_2]\,[NO]\right\} \tag{12}$$

$$S = \frac{6(NSR)[SO_2]_0}{D\,R_0^3}\,M'R^2 \tag{13}$$

k_A, k_B = rate constants, (mole/cm^3 min)

M = molecular weight of the sodium compound

D = particle density

R = radius of the unreacted core

R_0 = mean initial radius of the sodium sorbent particle

x = empirical stoichiometric constant that varies between 0 and 1

S = reactive surface area per unit volume

NSR = normalized stoichiometric ratio (2Na/S)

$[SO_2]_0$ = initial concentration of SO_2

M' = mass of sodium sorbent per mole of sodium

a = Stoichiometric coefficient, 0.5 (sodium bicarbonate), 1.5 (sodium sesquicarbonate)

Table 4-3 summarizes the rate constants and parameter "x" obtained from the data.

Sorbent	k_A (cm/min)	k_B (cm^4/min mol)	x
Sodium Sesquicarbonate	8.77	1.24×10^8	0.55
Sodium Bicarbonate	7.65	1.06×10^8	0.70

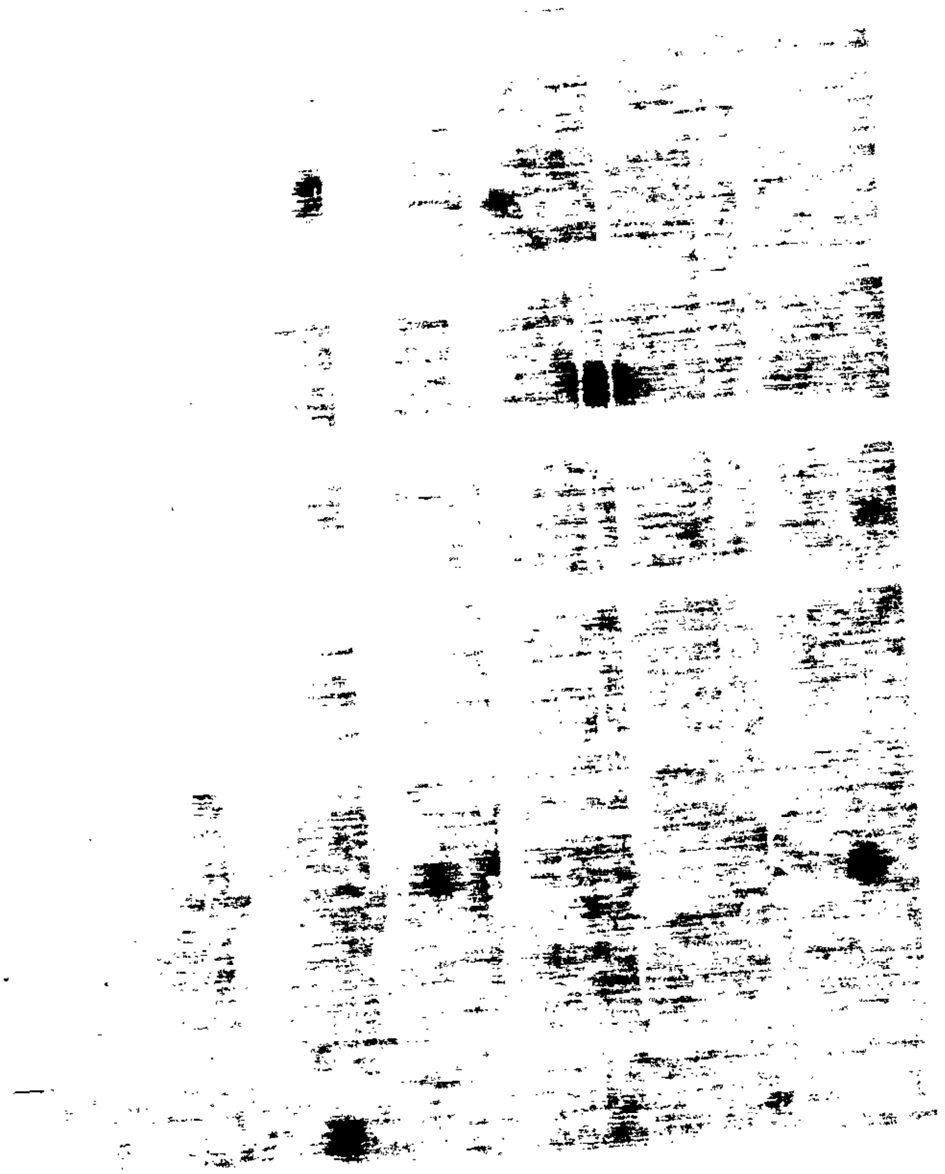
Table 4-3. Summary of the Model Parameters

The overall conversion, or utilization, as a function of time is obtained by integrating the above equations for R(t)

$$U(t) \equiv 1 - \left(\frac{R(t)}{R_o}\right)^3 \tag{14}$$

4.7.7 Summary

The bench scale tests developed a kinetic mechanism for SO_2 removal that can be used in process calculations. The bench scale results also support the work by Verlaeten, et al., which suggests that sodium pyrosulfite ($Na_2S_2O_5$) is an important intermediate in the formation of NO_2 and the removal of NO_x.



5 CALCIUM-BASED DSI

This section describes the technology used by calcium-based DSI systems to reduce SO_2 emissions. It describes both the injection of hydrated lime into the economizer and the injection of hydrated lime into the duct before the particulate control device with humidification. This section also describes the calcium-based DSI system at Arapahoe Unit 4 and objectives, methodology, and results of the test program. Section 4.0 describes sodium-based DSI.

5.1 Description of Calcium-Based DSI Technology

This section describes the chemistry of using calcium-based reagents to reduce SO_2 emissions. The DSI system at Arapahoe Unit 4 uses hydrated lime. It also summarizes the concerns in designing a calcium-based DSI system. For more information on the design of calcium-based DSI systems, see *Final Report, Volume 1: Public Design.*

5.1.1 Process Chemistry

Very few studies have investigated the chemical path that hydrated lime follows to capture SO_2, so it is not well understood. One of these studies, by Bortz, Roman, Yang, and Offen, has shown that hydrated lime's SO_2 capture depends on several competing reactions. Of these reactions, the four reactions that are significant are:

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 + H_2O \qquad \text{(Eqn. 5-1)}$$

$$Ca(OH)_2 + CO_2 \rightarrow CaSO_3 + H_2O \qquad \text{(Eqn. 5-2)}$$

$$Ca(OH)_2 \rightarrow CaO + H_2O \qquad \text{(Eqn. 5-3)}$$

$$CaCO_3 + SO_2 \rightarrow CaSO_3 + CO_2 \qquad \text{(Eqn. 5-4)}$$

5.1.1.1 Economizer Injection

The effectiveness of injecting the calcium-based reagent into the economizer depends on injecting and distributing the hydrated lime where the temperature of the flue-gas promotes the reaction of the reagent with SO_2 (Eqn. 5-1). Without humidification, hydrated lime performs best in a flue-gas temperature of 1,000°F.

5.1.1.2 Duct Injection with Flue-Gas Humidification

The flue-gas temperature at the outlet of the air heater is too low (about 300°F) for hydrated lime to react effectively with SO_2 reagents, but they would react more efficiently if the reactions occurred in liquid water. Flue-gas humidification systems inject water into the flue-gas between the sorbent-injection grid and the particulate control device. Generally, dual-fluid nozzles are used to inject large quantities of high-pressure air to atomize the injected water, and to ensure its complete evaporation before it enters the particle control device.

Depending on the type of sorbent, the rate of injection, furnace geometry, and other operating conditions, the use of flue-gas humidification and DSI with calcium-based reagents has achieved SO_2 removal rates from 20% to 50%.

5.1.2 Design Concerns

This section describes the limits on approach-to-saturation temperatures, dual-fluid atomizers, the effect of flue-gas humidification on particulate control devices, and criteria to consider when designing a flue-gas humidification system.

5.1.2.1 Economizer Injection

The design challenge for economizer injection is to inject and distribute the hydrated lime at a location within the temperature window, about 1,000°F. Outside of this temperature window, the hydrated lime reacts with other compounds and utilization decreases. Generally, this location is just before the economizer, but is commonly referred to as "economizer injection." Boiler tubing and other obstructions, however, may prevent the installation of the injectors within the temperature window or the positioning of the injectors for effective mixing.

There is even less data available for determining the flowrate of hydrated lime for economizer injection than there is for duct injection of sodium-based reagents. Theoretically, only one mole of calcium, compared to two moles of sodium, needs to be injected to remove a mole of SO_2. On a mass-basis, though, the injection rates for sodium- and calcium-based reagents are similar. Therefore, equipment designed to store and supply sodium-based reagents for duct injection is also appropriate for storing and transporting hydrated lime for economizer injection.

5.1.2.2 Flue-Gas Humidification

The more water injected into the flue-gas, the higher the humidity and the lower the dry-bulb temperature of the flue-gas. Liquid water in the flue-gas can damage the duct and FFDC, but as long as the injected water completely evaporates and remains in a vapor state, there is no limit to how much water can be injected.

The adiabatic-saturation temperature (T_{sat}) of the flue-gas is the temperature at which the flue-gas entering the duct would become saturated with no gain or loss of energy in the flue-gas duct. This property remains constant and is lower than the flue-gas temperature. As the humidification water is injected, the dry-bulb temperature of the flue-gas decreases and approaches the adiabatic-saturation temperature. The approach-to-saturation temperature (T_{AS}) is the difference between the dry-bulb temperature of the flue-gas and the adiabatic-saturation temperature, as shown below:

$$T_{App} = T - T_{sat} \qquad \text{(Eqn. 5-5)}$$

As the approach-to-saturation temperature becomes smaller, SO_2 capture increases. Incomplete mixing of the injected water and flue-gas, however, limits how small the approach-to-saturation temperature can become without the formation of liquid water. Incomplete mixing causes temperature gradients and localized areas of complete saturation to form in the flue-gas. Thus, as the approach-to-saturation temperature decreases, these areas of complete saturation may deposit liquid water and solids onto the duct wall. For duct humidification, the generally accepted practical limit for approach-to-saturation temperatures is approximately 20°F or about 50% relative humidity. Because of the high risk of wetting an FFDC's bag-filters and the expensive possibility of replacing them, a more practical approach-to-saturation temperature with FFDCs is closer to 40°F.

The optimum operating point for a humidification system is a compromise between reliable operation and SO_2 removal performance. While a small approach-to-saturation temperature for increased SO_2 capture is desirable, localized-wetting problems require larger approach temperatures.

5.2 Economizer Injection and Flue Gas Humidification Systems at Arapahoe Unit 4

This section describes the economizer injection and flue-gas humidification systems at Arapahoe Unit 4. As the same two DSI systems are used to store and transport both calcium- and sodium-based reagents (and they are described in Section 4.2), this section does not describe the storage and transport systems. *Volume 1* describes the DSI and flue-gas humidification systems at Arapahoe Unit 4 in more detail.

5.2.1 Economizer Injection of Hydrated Lime

Because of the configuration of the boiler near the economizer, it was initially planned to locate the injectors at the inlet of the economizer. At this location, there are no obstructions to locating the injectors through the north wall. In addition, the boiler is a 15-ft wide by 40-ft long rectangle at the economizer. By injecting through the north wall, therefore, the injection jet would only have to penetrate across the short side of the boiler.

Temperature measurements, however, determined that the optimum flue-gas temperatures occur in the center of the superheat section of the boiler. Unfortunately, a superheat header blocks the north wall and limits the injection location to the sidewalls only. Injection through the side walls requires that the injection jet penetrate across the long side of the boiler. So, the optimum location for the lances for minimizing the distance the injectors would have to penetrate is on the front and back walls, but the optimum temperature occurred where injecting only through the side walls was possible. It was decided to compromise and proceed with the sidewall injection in the superheater (although referred to as economizer injection) even though it was not expected to distribute the reagent uniformly.

5.2.2 Flue-Gas Humidification

As the reagent injection system for flue-gas humidification is the same as that for sodium-based reagents, this section describes only the humidification system. The flue-gas humidification system at Arapahoe Unit 4 is divided into the following four subsystems:

- Water supply system
- Compressed air (atomizing air) system
- Injection lances
- Shield air system.

Figure 5-1 shows a simplified P&ID of the flue-gas humidification system.

5.2.2.1 Water Supply System

The flue-gas temperature is measured by a 12-thermocouple grid in the flue-gas duct. Originally, the grid was located about halfway between the injection grid and the FFDC, but early tests indicated that damp ash and sorbent were causing the thermocouples to read the temperatures too low. To minimize the effect of the damp ash and sorbent, the thermocouple grid was moved to just ahead of the FFDC. In addition, shields were added to the thermocouples to prevent the damp ash and sorbent from contacting the thermocouples.

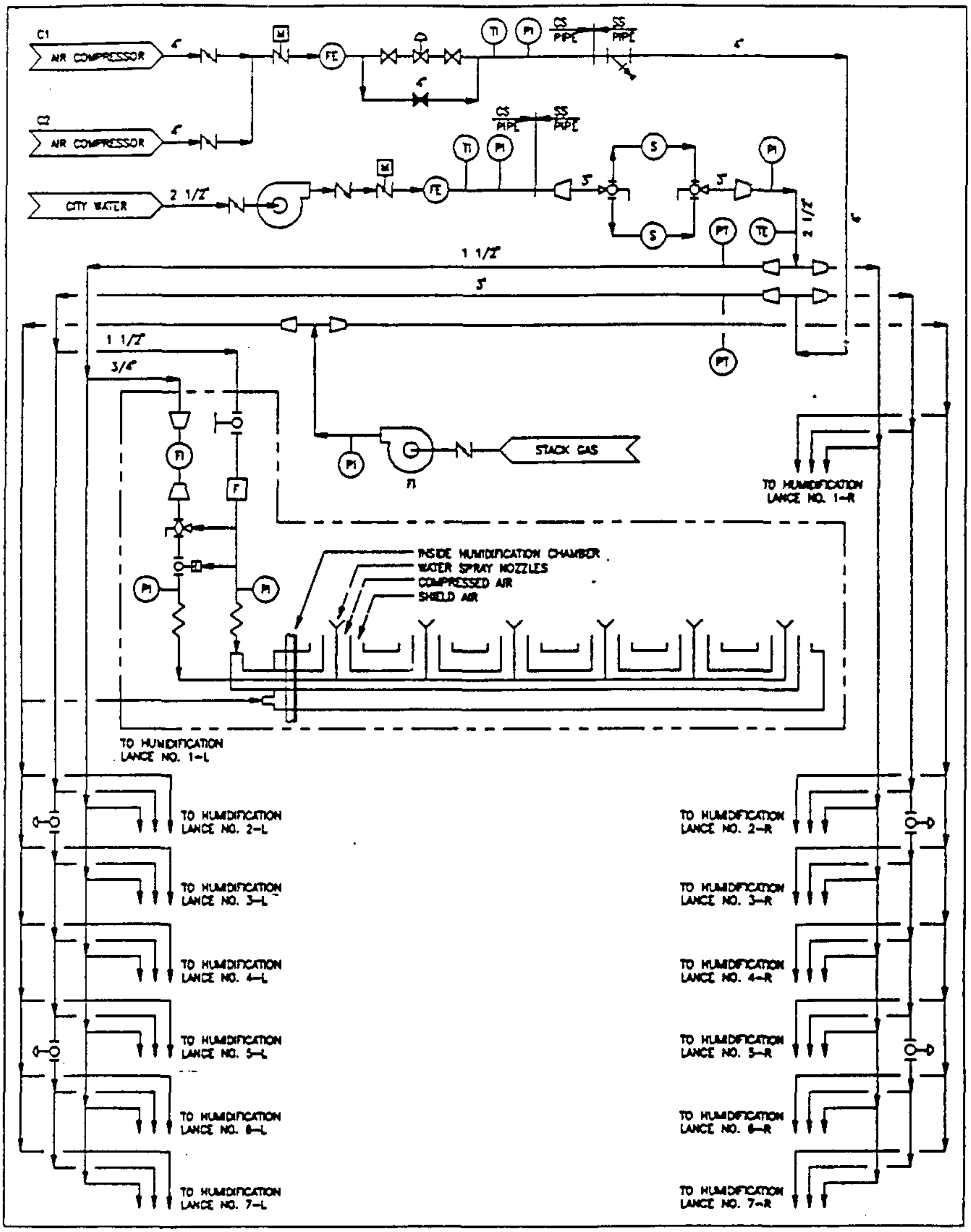


Figure 5-1. Simplified P&ID of the Flue-Gas Humidification System

The water flowrate may be controlled manually by establishing a flowrate setpoint or automatically by establishing a flue-gas temperature downstream of the humidifier. The automatic control system uses the temperature measurements from the thermocouple grid.

5.2.2.2 Atomizing Air System

The atomizing air system uses two compressors and operates them together to produce up to 3,200 acfm at 140 psig. The DCS and a pressure-control valve regulate the pressure of the atomizing air. Air pressure can be set manually or can be automatically controlled by establishing a setpoint above the operating water pressure.

To evenly distribute the atomizing air in the duct, the differential pressure between the water and the atomization air must be equal. There are four control valves located on an air-header system to control the airflow to each of the lances. These control valves compensate for the larger flow of water to the lances at the bottom of the duct due to greater static head at these locations. The four control valves can be positioned manually by observing pressure differentials between the water and atomizing air or automatically by establishing a differential setpoint.

5.2.2.3 Injection Lances

The inlet duct to Arapahoe Unit 4's FFDC is unusual. When the unit's ESP was replaced with an FFDC in 1980, about 100 feet of straight duct was added. The inlet to this long, straight duct was an obvious place to locate the humidification system, so a temperature traverse was performed at the air heater exit to determine the uniformity of the temperatures across the duct. Although some variations in temperature were found, they were not expected to cause any problems and the air heater exit was chosen as the location for the humidification injection lances.

Once the injection location was chosen, B&W designed the lances based on the experience they gained at Ohio-Edison's Edgewater station. Using general operating conditions for Arapahoe Unit 4 and an approach-to saturation temperature of 45°F, B&W determined that this system required a 12-wide by 7-high grid consisting of 14 injection lances, each with 6 nozzles. The DSI and flue-gas humidification systems use the same injection location, so the injectors for both systems are interspersed. Figure 5-2 shows a photo of the DSI and humidification grid.

Based on performance data obtained by B&W at its Alliance, Ohio Research Center, B&W developed a proprietary computer program to predict the evaporation of water injected by its I-Jet nozzles. At the operating conditions used to determine the injection flowrate, the computer program predicted that 99.8% of the injected water would evaporate before it entered the FFDC.

5.2.2.4 Shield Air System

Shield air is also supplied to the lances to help prevent the flue-gas from depositing solids on the nozzles and lances. A rapper is provided to help remove any solids that may have collected on the lances.

5.3 Calcium-Based DSI Test Program Objectives

The objectives of the calcium DSI test program were to: (1) determine the effect of various sorbent injection and humidification system parameters on SO_2 removal, (2) determine optimum system performance for long-term operation, and (3) document day-to-day performance and its impact on the boiler back end equipment.

The calcium injection tests were performed following the combustion system retrofit to the Arapahoe Unit 4 boiler. Two phases of the test program were characterized by the different calcium injection locations: in the duct downstream of the air heater, (ahead of the FFDC), and in the convective pass of the economizer at a higher flue-gas temperature.

One of the primary operating parameters for sorbent injection processes is the calcium-to-sulfur molar ratio (Ca/S), which relates the amount of sorbent injected relative to the amount of sulfur in the flue-gas. When humidification is utilized, the approach to adiabatic saturation temperature (T_{app}) of the flue-gas also becomes an important parameter. The humidification system was used to vary T_{app} from 20 to 70°F above the

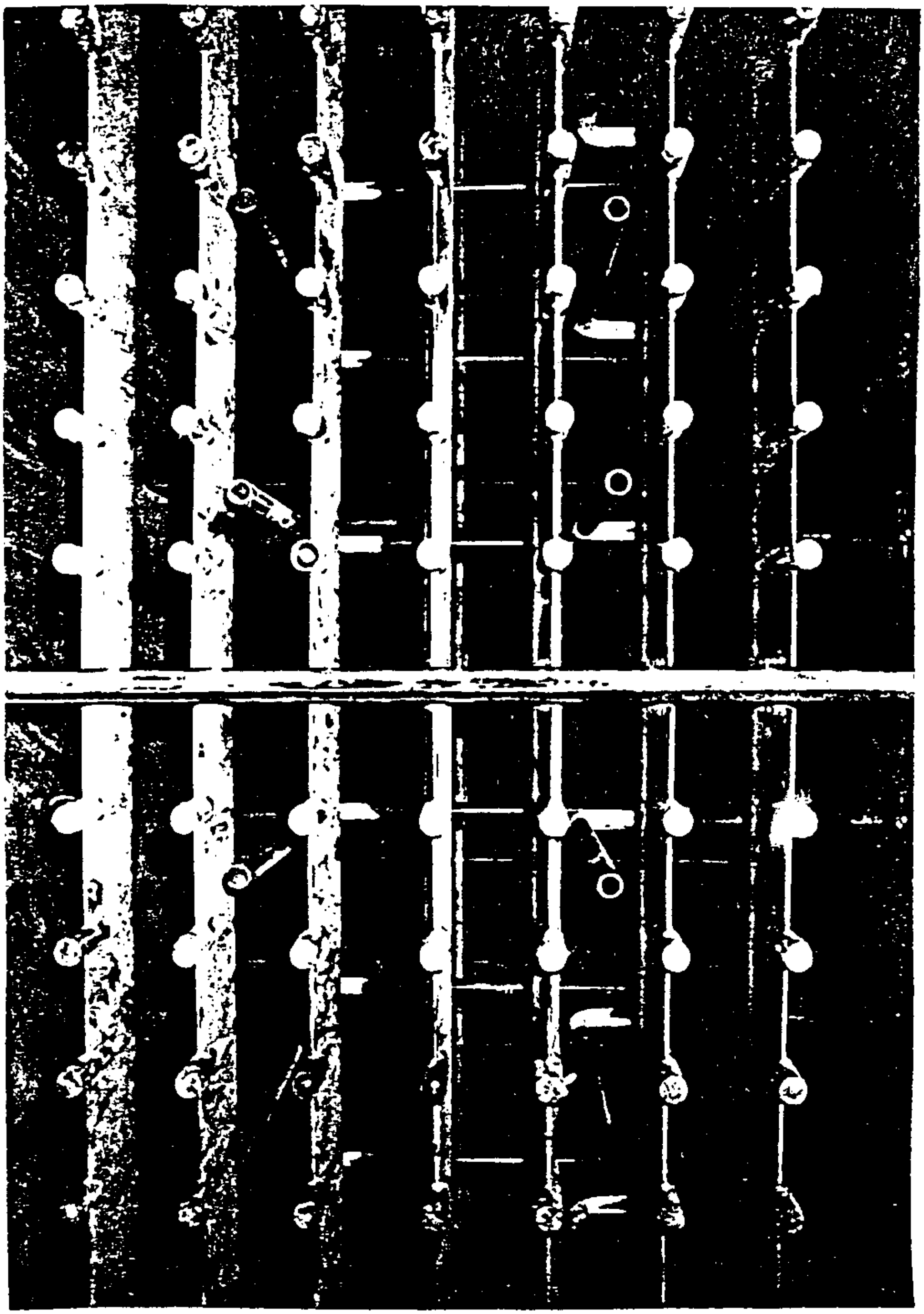


Figure 5-2. Photo of DSI and Humidification Lances at Air Heater Exit

dew point. Saturation temperatures of the flue-gas ranged from 112 to 118°F, depending on boiler operating conditions. Parametric variation of the Ca/S ratio, approach to adiabatic saturation, and boiler load were the primary parameters investigated during the calcium injection tests. Additional details of these calcium dry sorbent tests can be found in the test report "Integrated Dry NO_x/SO_2 Emissions Control System, Calcium-Based Dry Sorbent Injection" (Test Period April 30 to November, 1993), Shiomoto et al., 1994.

5.4 Calcium-Based DSI Test Program Methodology

Calcium injection tests consisted of two types: parametric tests, and long-term operation. Long-term operation was performed for the duct injection of calcium, in order to obtain long-term experience with normal boiler load following operation. During long-term operation of the other technologies associated with the integrated system, the system was operated in an automatic mode with a data logger used to collect data. However, with the calcium and humidification system, test personnel were on-site 24 hours per day during the long-term operation, in order to insure proper operation of the sorbent injection and humidification systems. Parametric testing was performed during steady boiler load conditions (typically during daylight hours) and setting up the desired Ca injection/humidification system parameters. Specific measurements of boiler, sorbent injection, and humidification operation and boiler/FFDC emission measurements were conducted.

5.4.1 *Instrumentation*

The gas analysis instrumentation, as described previously, was utilized for the sorbent injection/humidification tests.

5.4.1.1 Approach to Adiabatic Saturation Temperature

The measurement of the flue-gas temperature and its approach to adiabatic saturation was a key variable in characterizing the humidification and SO_2 removal process with calcium-based sorbents. The use of a thermocouple grid should permit an accurate determination of the flue-gas dry-bulb temperature, however, problems with wet, or partially wet thermocouples, resulted in lower than actual gas temperature measurements. To address this problem, the thermocouple grid was moved further downstream and shields were placed in front of the thermocouples most susceptible to wetting. While this improved the gas temperature measurement, the grid still did not accurately indicate the dry-bulb temperature.

Wet-bulb temperatures were manually performed by wrapping a cloth around a thermocouple and wetting the wick prior to insertion into the flue-gas duct.

However, because of the inability to measure an accurate dry-bulb temperature, the approach to saturation temperature could not be readily determined by the direct measurement of wet-bulb and dry-bulb temperatures. An alternate approach was developed, which involved calculating the wet-bulb and dry-bulb temperatures by performing an energy balance on the duct. Appendix G outlines this procedure.

5.4.2 Test Methods

Parametric testing was performed by carefully controlling the various sorbent injection, humidification, and boiler variables in a systematic manner, to determine their effect on system operation and SO_2 removal. Key system variables included:

- Boiler Load
- Sorbent Injection Rate (Ca/S molar ratio)
- Humidification (approach temperature)

For the present test program, the approach temperature was varied from 20 to 76°F by varying the amount of water injected. The Ca/S ratio was varied from nominally 0.4 to 2.2. The majority of the tests focused on approach to adiabatic saturation temperatures of 30 to 40°F and Ca/S molar ratios of nominally 2.

Once the desired test conditions were established, the system was allowed to stabilize to insure steady state operation prior to the start of a test. During the test period, documenting the system operation was performed by completing boiler control room, sorbent injection, and humidification data sheets from the DCS control screens. A composite set of gaseous emissions at the economizer exit and FFDC exit was also obtained. Additional data was obtained depending on specific test objectives. These additional measurements could include:

- Detailed gas or FFDC compartment samples.
- Sorbent samples.
- FFDC hopper ash samples.

Following data collection, additional adjustments to the sorbent injection or humidification variables were performed and the process was repeated.

While long-term operation of the sorbent injection and humidification were performed to assess typical operation, totally automatic control of the system was not permitted. Supervision of the sorbent injection system and humidification operation was required to guard against injection system plugging or over-humidification. CEM measurement between the air heater exit and stack monitored SO_2 removal performance, and key boiler operating parameters were obtained from the DCS.

5.4.3 Quality Assurance/Quality Control

5.4.3.1 Approach Temperature

Several means of verifying the actual flue-gas temperature and the amount of humidification were used during the test program. One means of checking the thermocouple grid was to monitor the steady state FFDC outlet temperatures. Two FFDC exit temperatures were available, one was a single thermocouple and signal transmitter located at the FFDC exit, and the second was a thermocouple system located in the stack duct, close to the Altech CEM monitor.

The gas temperature measurements at the exit of the FFDC confirmed that the grid measurements were in error. Temperature traverses of the stack duct were also performed to verify the FFDC exit temperatures. Finally, additional thermocouples were installed at the ID fan inlet ducts (four total) to provide a better means of monitoring FFDC exit temperature. All of these verifications indicated that the equilibrium FFDC exit temperatures were higher than the average measurement by the thermocouples at the inlet grid during steady state tests at high humidification rates. While measuring the temperature at the exit to the FFDC was sufficient for long-term parametric tests which are conducted at steady state conditions, it was not adequate for long-term load following.

The humidification calculations determined the flue-gas saturation temperature and the humidified gas temperature, given the boiler and water input parameters. The calculations also confirmed that when the humidification water flow rates were high, the measured grid temperatures were being biased below the dry-bulb temperature. To establish a test condition, the equations were used to determine the required water flow rates for the approach temperature set point. Verification of the calculations were also indicated by the steady state FFDC outlet temperature measurements.

Wet-bulb measurements were performed to confirm that the calculated saturation temperatures for the flue-gases were accurate. Wet-bulb temperature measurements were within one degree Fahrenheit of the calculated saturation temperatures and verified the use of the calculation methodology.

5.5 Calcium-Based DSI Test Program Results

The results of the calcium dry sorbent injection will be presented in the following subsections. The properties of the calcium hydroxide used for these tests will be presented first, followed by the air heater outlet duct injection and finally the economizer injection test results.

5.5.1 $Ca(OH)_2$ Characteristics

The chemical composition and physical characteristics of the calcium hydroxide [$Ca(OH)_2$] used for the test program, both duct and economizer injection, are shown in Table 5-1. The particle size distribution by sedimentation analysis is shown in Figure 5-3.

Source:	Pete-Lien & Sons
Calcium Content:	68 wt% CaO[1]
Particle Size (MMD by sedimentation):	2.67 microns
BET Surface Area:	14.8 m^2/gm

[1] Note: pure $Ca(OH)_2$ has a CaO content of 75.6 wt percent

Table 5-1. $Ca(OH)_2$ Characteristics

5.5.2 Duct Injection and Humidification

The primary parameters that control the SO_2 removal of the duct injection/humidification system are: (1) the approach to adiabatic saturation temperature (T_{app}), and (2) the amount of $Ca(OH)_2$ injected (i.e., Ca/S molar ratio).

5.5.2.1 Effect of Approach Temperature

Figure 5-4 shows SO_2 removal as a function of approach to adiabatic saturation temperature and Ca/S ratio. Although each test was normally initiated with a target Ca/S ratio of 1.0, 1.5 or 2.0, maintaining a consistent sorbent feedrate throughout the duration of a test was often difficult. For this reason, the data in Figure 5-4 were grouped into three Ca/S ratio ranges centered at 1.0, 1.5, and 2.0. The data show that the overall behavior of the SO_2 removal as a function of approach to adiabatic saturation temperature was as expected: the SO_2 removal increased at higher levels of humidification (e.g., lower T_{app}). At a high approach to adiabatic saturation temperature of 75°F, SO_2 removal was only 12 percent at a nominal Ca/S ratio of 1.5. Decreasing T_{app} to 30 °F improved the SO_2 removal to 28 percent. If the humidification water flow was increased to produce T_{app} of 20°F, the SO_2 removals increased to 35 percent.

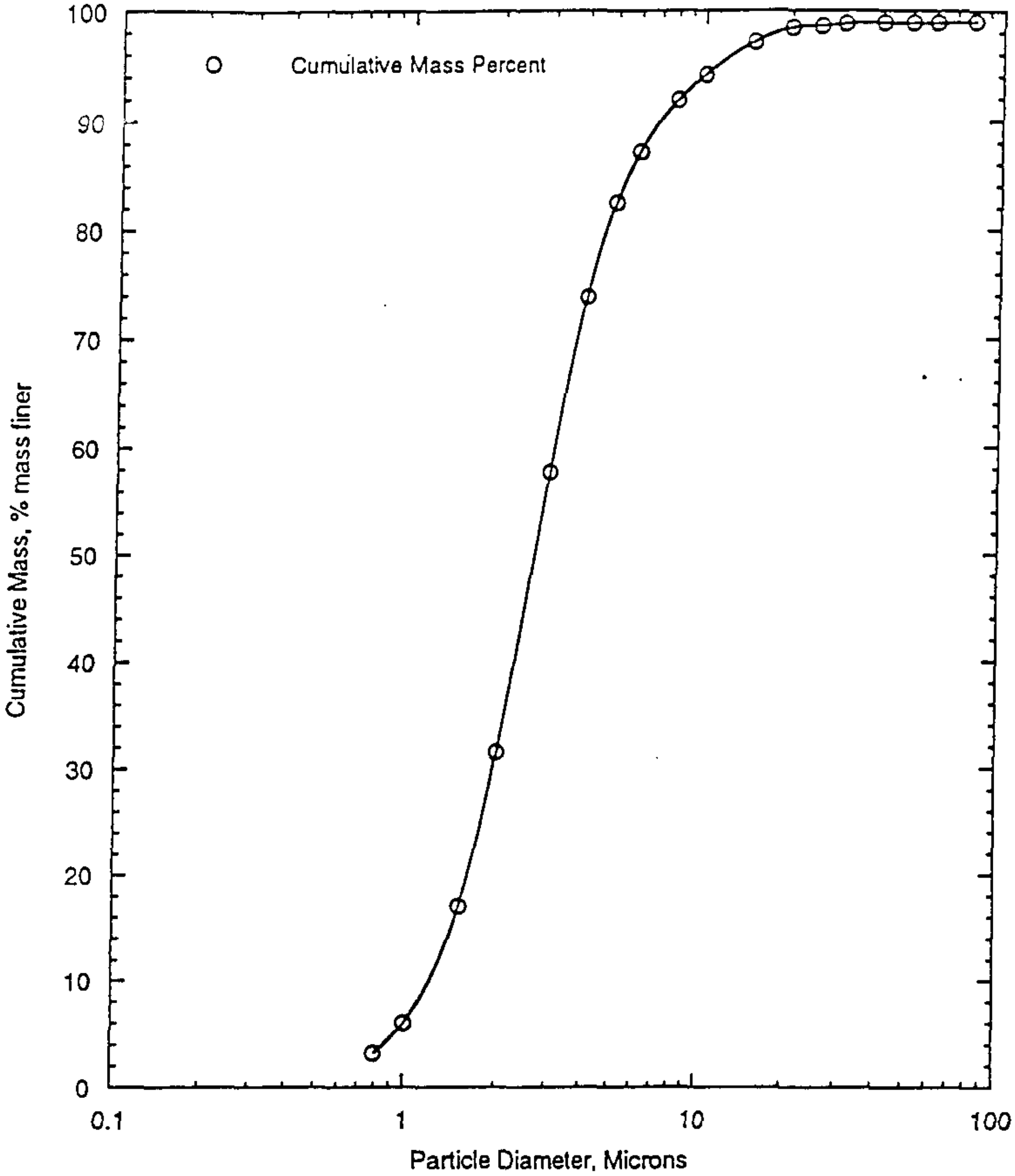


Figure 5-3. Ca(OH)$_2$ Particle Size Distribution (by Sedimentation)

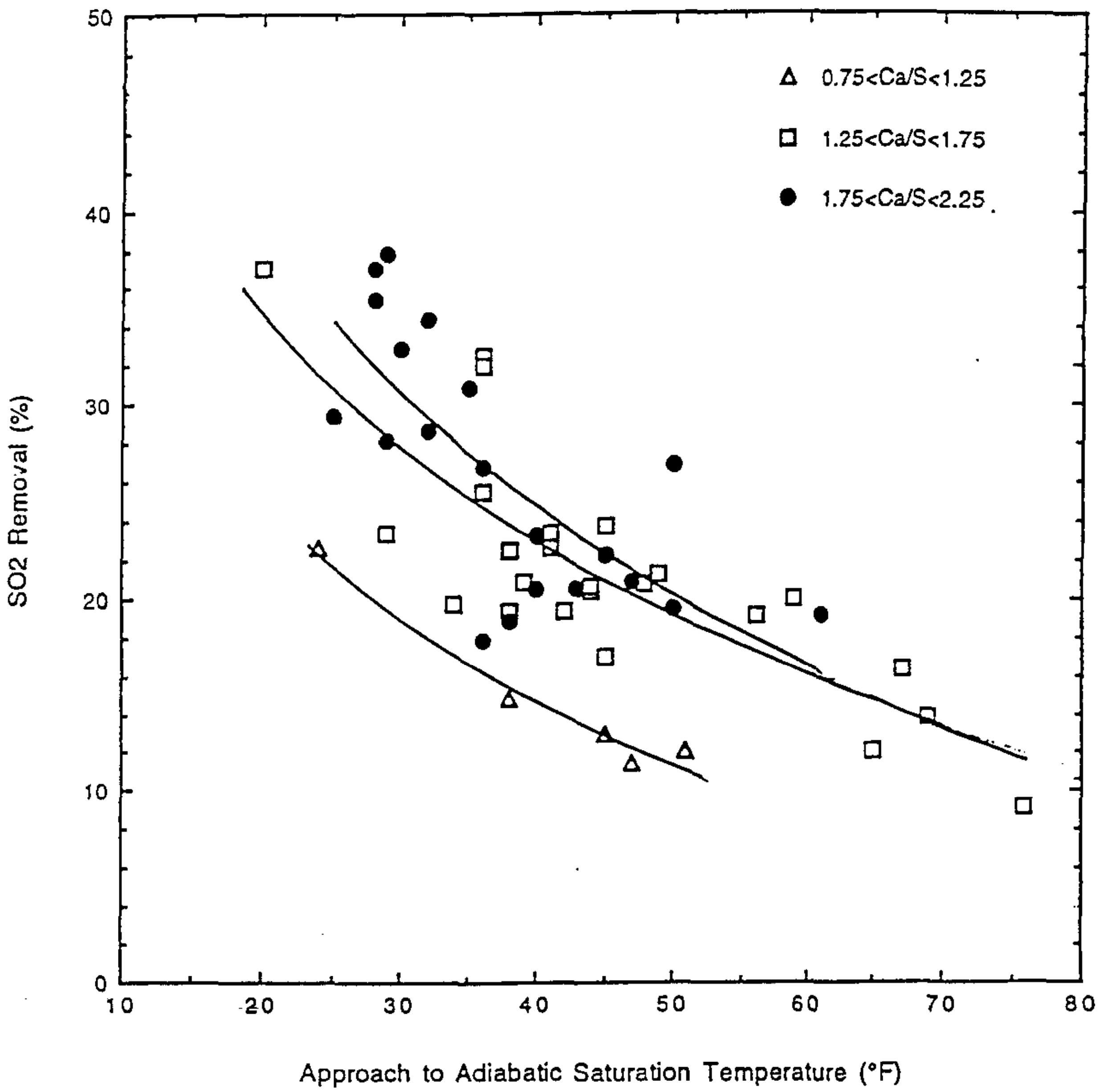


Figure 5-4. SO_2 Removal versus Approach to Adiabatic Saturation Temperature

The data in Figure 5-4 also show that the SO_2 removal effectiveness decreases as the Ca/S ratio approaches 2.0. When the Ca/S ratio is increased from 1.0 to 1.5, the SO_2 removal increases from 19 to 28 percent. However, when the nominal Ca/S ratio was raised to 2.0, the SO_2 removals only increased to 31 percent. This behavior results from the "overabundance" of sorbent at Ca/S ratios in excess of 1.5, which causes the sulfation process to be less efficient on the basis of moles of sulfur removed per mole of calcium injected.

Another point to be made regarding the data presented is the effect of boiler load. The data points shown in Figure 5-4 cover a boiler load range from 50 to 114 MWe. No trends in SO_2 removal with load were evident, within the typical day-to-day variation of the data.

5.5.2.2 Effect of Calcium to Sulfur Ratio

The effect of the amount of calcium injected, or Ca/S molar ratio, is shown in Figure 5-5. In this figure, the data points are shown for nominal 5°F differences in the approach to adiabatic saturation temperature. Curves have been drawn through the data points for approach temperatures of 25 to 30°F and 40 to 45°F to better show the trends. As expected, the SO_2 removal increases as the Ca/S ratio increases, with the incremental increase becoming less and less at Ca/S ratios in excess of 1.5. Again, the effect of lower approach to adiabatic saturation temperature is evident.

5.5.2.3 FFDC Compartment Measurements

Gas samples were also obtained from the exit of each FFDC compartment to further investigate the sorbent/FFDC interactions that may impact SO_2 removal efficiency.

The results of the compartment-by-compartment calculated SO_2 removal measurements are shown in Figure 5-6. For these tests, the unit was operated at 112 MWe, the humidifier at a 30°F approach to adiabatic saturation temperature, and the $Ca(OH)_2$ was injected at a Ca/S ratio of 2.1. For this test, the overall SO_2 removal based on the stack and inlet measurements was 35.4 percent. The compartment-averaged SO_2 removals was

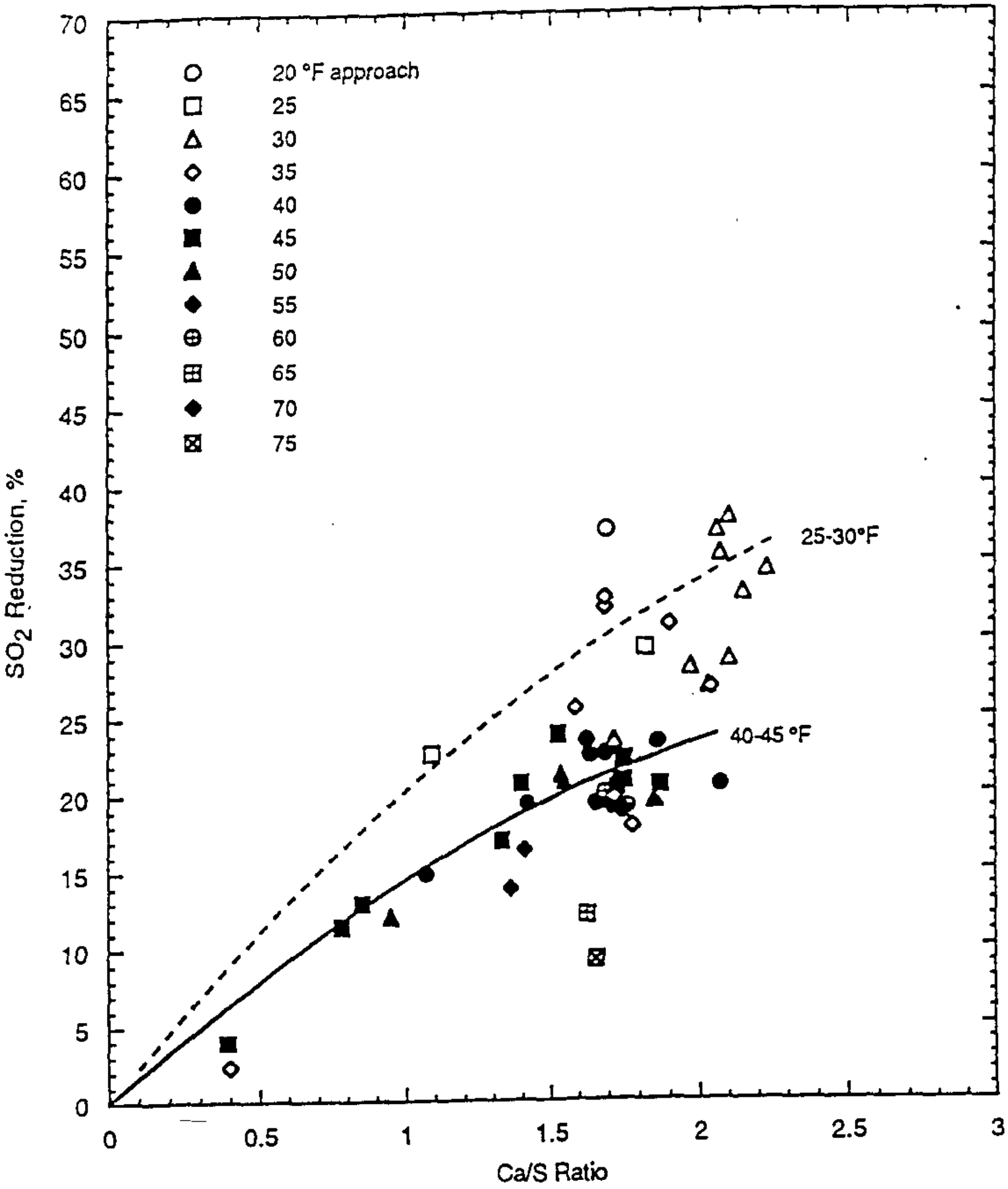


Figure 5-5. The Effect of CA/S Ratio on SO_2 Removal at Various Approach to Adiabatic Saturation Temperatures

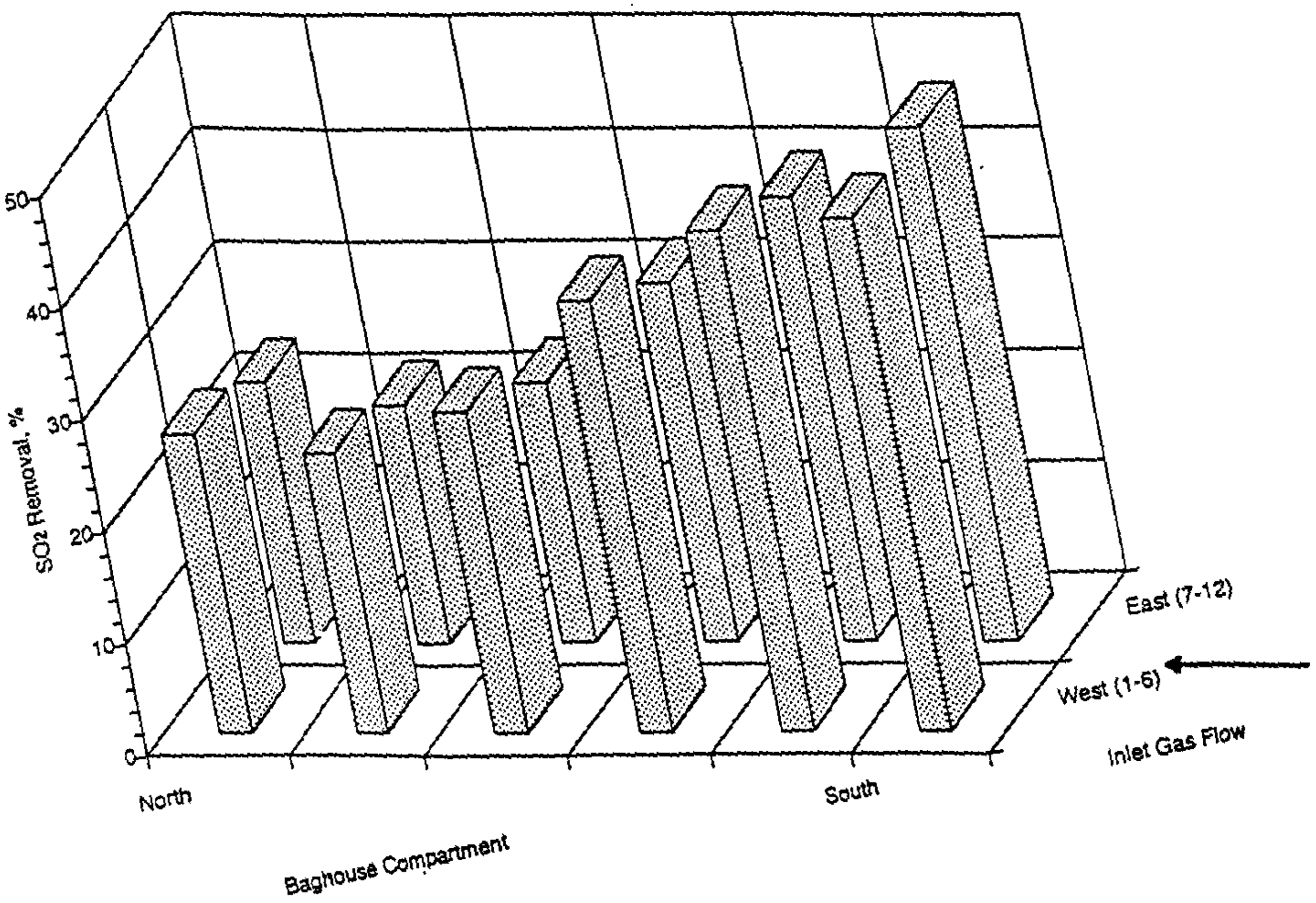


Figure 5-6. Compartment-by-Compartment SO_2 Removal Measurements with Calcium Injection (Load: 112 MWe; T_{app} 30°F; Ca/S: 2.1)

33 percent, which show these two values are in reasonably good agreement. The highest SO_2 removals are seen in the compartments at the entrance to the FFDC, and decrease uniformly toward the back of the FFDC (e.g., from south to north). The comparison between east and west compartment indicates slightly higher removals on the west side of the FFDC, although the difference was small and may not be significant. The SO_2 removals at the front (south) of the FFDC were in the range of 40-45 percent, while from the back compartments (north) were in the range of 21 to 27 percent.

The higher SO_2 removals associated with the front compartments would suggest higher calcium loadings and some additional SO_2 removal occurring within the compartments. The higher SO_2 removals may also indicate that the sorbent deposited in the front compartments is still damp, and thus more reactive than the material deposited in the back compartments.

In order to characterize the composition of the solid product of the duct injection/humidification process, laboratory analyses were performed on composite fly ash/sorbent samples obtained from the individual FFDC hopper. These samples were analyzed for calcium, sulfate and sulfite. Calcium content was determined using an induced coupled plasma analysis (EPA Method 200.7). Sulfate and sulfite were determined with ion chromatography (EPA Method 300.1) and titration (ASTM Method 4500), respectively.

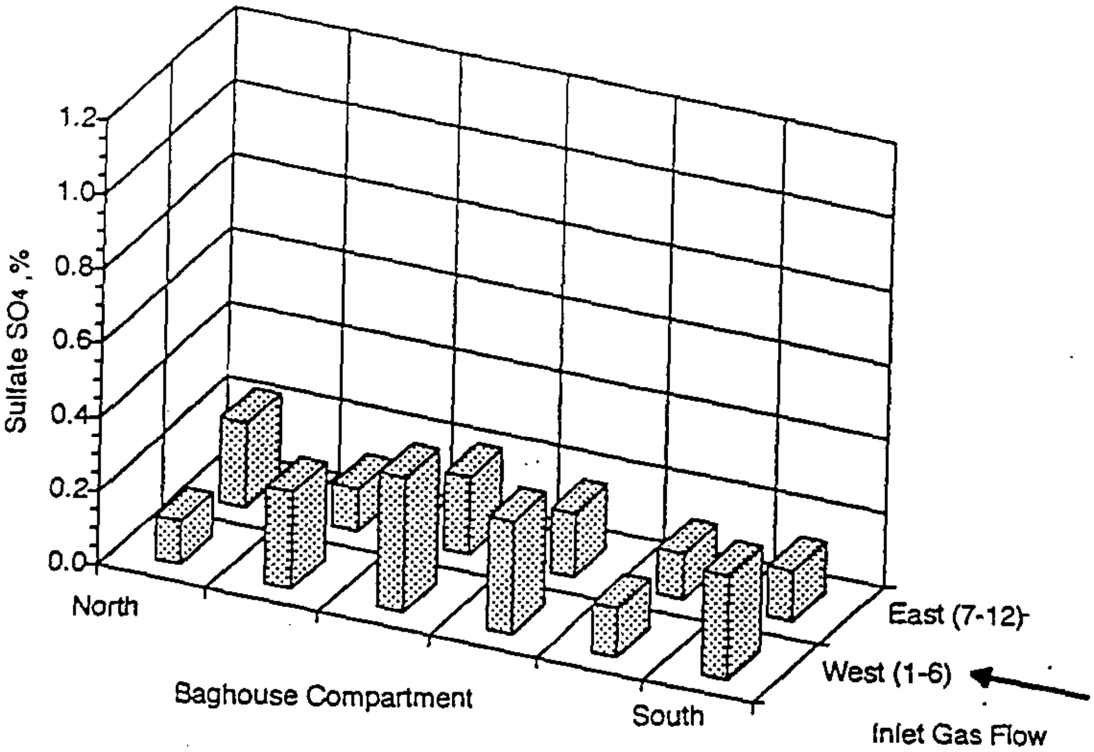
Tests conducted previously showed that without sorbent injection, the fly ash alone had a nominal calcium content of 2.1 percent by weight. The results of the calcium analyses for the current test indicate that although there was a little variation, the calcium concentration was similar in all twelve compartments. However, this does not necessarily mean that the calcium was equally distributed among the compartments, rather only that the calcium to fly ash ratio was relatively equal on a compartment-by-compartment basis. Previous testing without sorbent injection has shown that the time required to evacuate each hopper after a FFDC cleaning cycle decreases dramatically between the hoppers located at the front and rear of the FFDC. This trend indicates that the majority of the fly ash was deposited in the forward compartments. Therefore, the results indicate that the sorbent was also preferentially deposited in the forward compartments.

The results of the sulfate and sulfite analyses (Figure 5-7), show that sulfite was found to be the predominate species in each compartment. The sulfite concentration results are consistent with the compartment-by-compartment SO_2 removal data. Although, there appears to be no correlation between sulfate concentration and compartment location, the sulfite results tend to be highest in the forward compartments, and generally decrease toward the rear compartments.

A measure of the utilization of the calcium in each sample may be determined from the molar ratios of calcium and sulfur. Since one mole of calcium is required to completely react with a single mole of sulfur, the molar sulfur-to-calcium ratio is a direct measure of the utilization. Figure 5-8 shows the calculated utilizations based on the calcium concentrations corrected for the fly ash contribution. The results show that the utilizations are generally highest in the front half of the FFDC, where the sulfite levels are also highest.

Another objective of the solids analyses was to confirm the stoichiometric ratio calculated from the sorbent feedrate and the gaseous SO_2 measurements. The stoichiometric ratios can be calculated separately for each compartment, and then averaged, in order to provide an overall value. The Ca/S ratio in each compartment can be calculated using the compartment-by-compartment SO_2 removal results (Figure 5-6) and utilization results (Figure 5-8(a)).

To do so requires the measurement of the SO_2 removal in each compartment, in addition to the utilization calculation. The arithmetic average of this data (Ca/S = 1.9) is in reasonably good agreement with the feedrate calculation (Ca/S = 2.1). These results are shown in Figure 5-8(b).



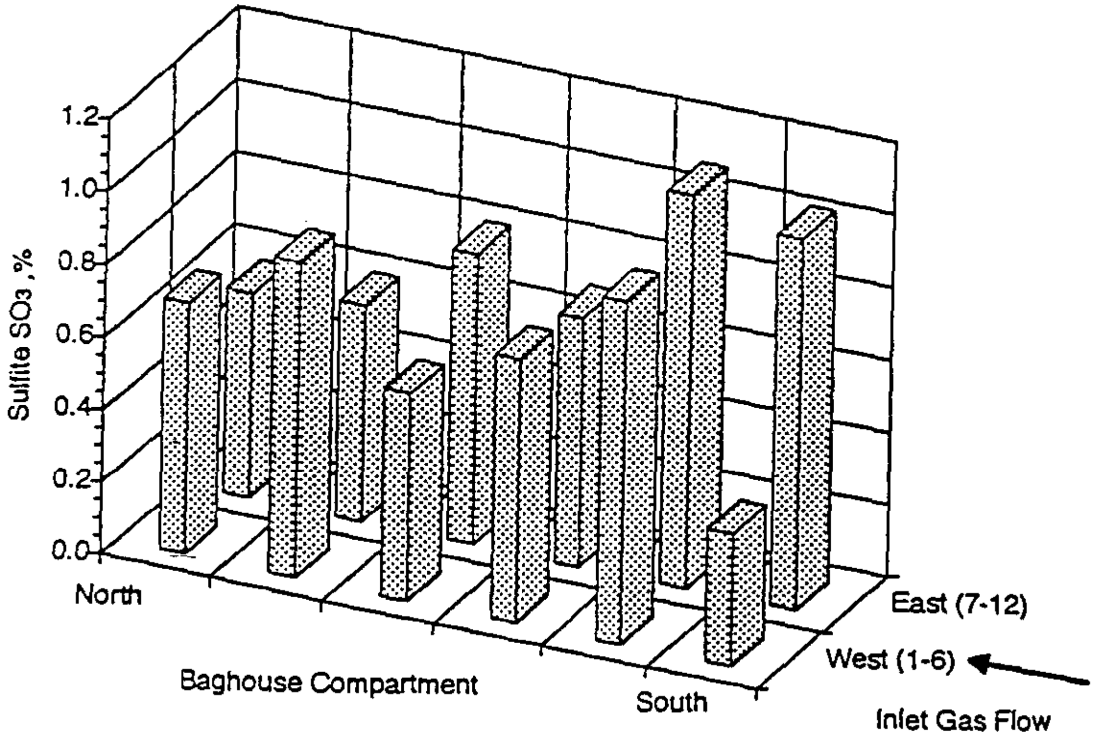
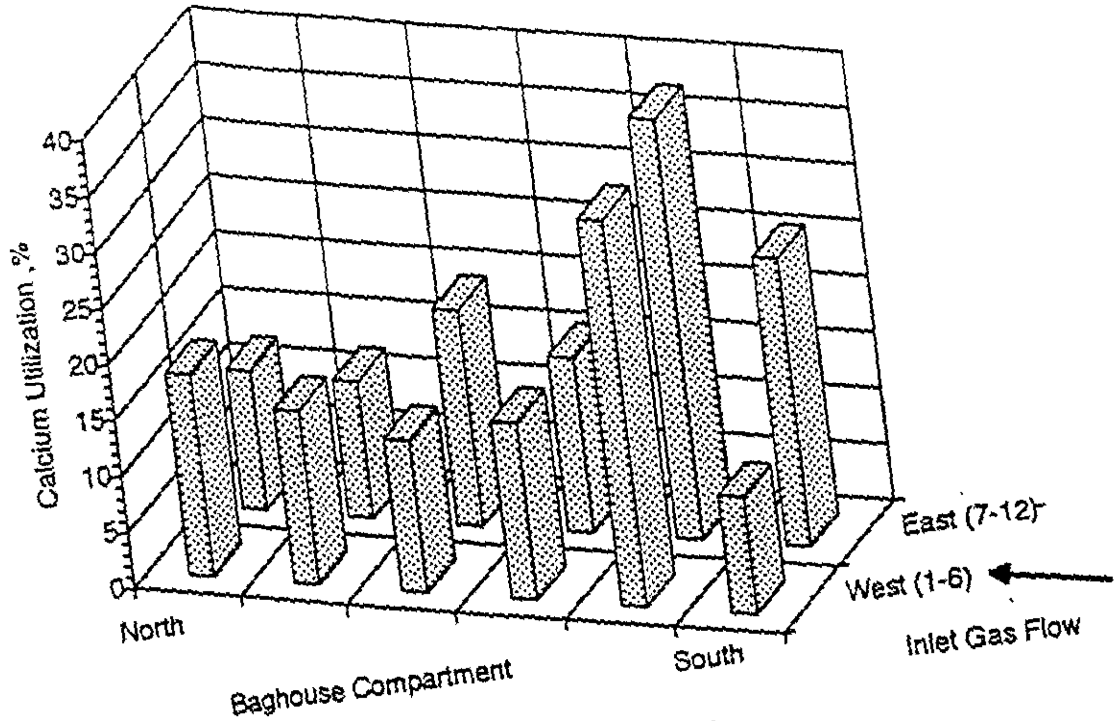
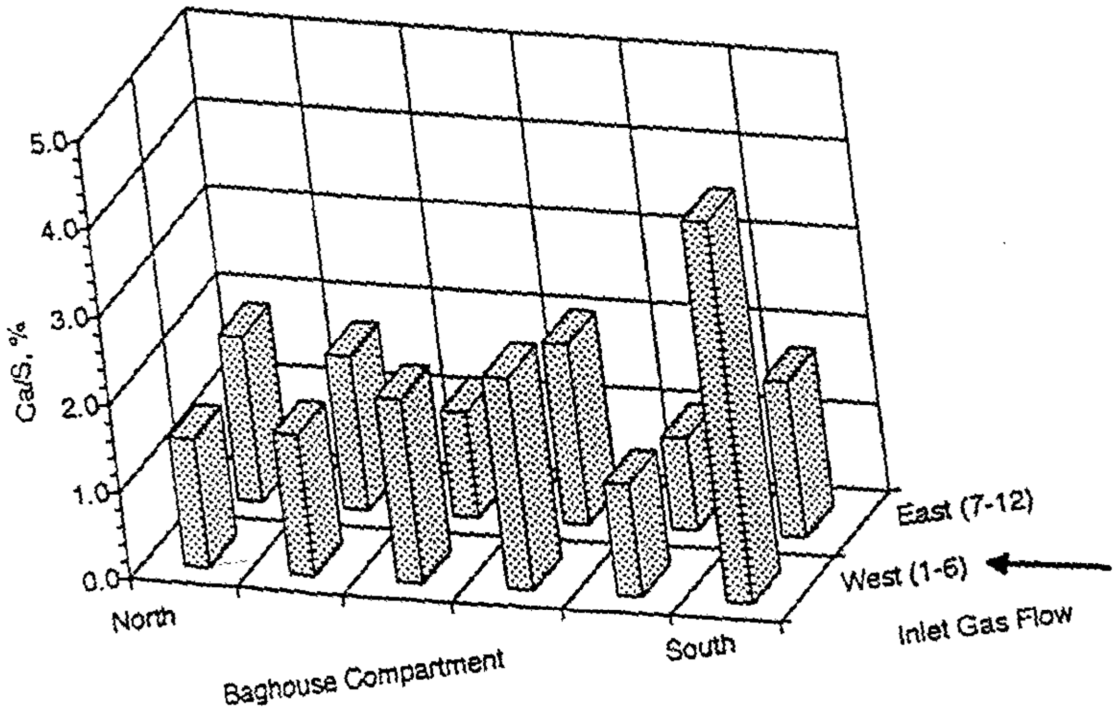


Figure 5-7. Sulfate and Sulfite Results for Individual FFDC Hopper Samples



(a) Calcium Utilization



(b) Ca/S Ratios

Figure 5-8. Utilization and Ca/S Calculations for Individual FFDC Hopper Samples

Compartment No. 1 on the southwest corner showed the most variation relative to the rest of the FFDC in the previous figures. The data indicate that more sorbent flow was being deposited in this compartment, as indicated by the high Ca/S ratio, poor Ca utilization, low sulfate/sulfite concentration and relatively high SO_2 removals.

5.5.2.4 Duct Deposits and System Operability

At the start of the duct injection/humidification test program, there were two concerns about the overall operability of the system. The first was the potential for deposition of sorbent and ash on the duct walls. The second concern was the impact of the duct humidification system on the overall operability of the FFDC.

Inspection of the sorbent injection and humidification grids, and the flue-gas duct ahead of the FFDC, were performed during unplanned boiler outages. There was slight ash buildup on some of the humidification lance surfaces, but these deposits were generally of a powdery nature and could be easily removed. The deposits on the humidification lances appeared to be fly ash and there were no areas where extensive blockage occurred.

The sorbent injectors were generally free of deposits, except at the tip. Several injectors were partially plugged with material that was hard and had to be chipped off. These deposits may have resulted from exposure to water or moisture that created a cement-like deposit, however, these deposits did not cause a total blockage of any injector.

Overall, the majority of the duct was free of deposits. There were only two areas where a build up of sorbent and ash occurred; one approximately 60 feet downstream of the injection plane where the duct went from a horizontal run to an upward slope toward the FFDC entrance, and the second at the location of the air foil located approximately 40 feet from the injection plane.

The deposits at the duct transition were located in the vicinity of the old thermocouple probes and were generally on the right, or east, side of the duct. The transition from a horizontal run to an upward slope and the obstruction of the thermocouple probe grid may have contributed to the deposit. The deposits appeared to be a mixture of calcium and ash, were not easily crumbled. They could build to heights of two to three feet. Plant personnel indicated that after the construction of the FFDC, fly ash deposits were known to accumulate in this area on the right side of the duct. The air foil that was subsequently installed, reduced, but did not eliminate, the ash buildup in this area. The addition of sorbent injection appears to have increased the amount of buildup, but it is believed that the buildup eventually reaches an equilibrium and would be manageable.

The second location of sorbent/ash accumulation was at the base of the previously mentioned air foil gas diverter. During the inspections, deposit piles on the order of three to five feet in height were noted. These deposits were attributed to the obstruction created by the air foil, which resulted from ash/sorbent impacting the air foil, or supporting cross member. Since the deposits were relatively dense, they accumulated at the base of the air foil. It is likely this buildup would continue to grow due to the direct impact of sorbent and ash.

When possible, the deposit accumulations were broken up and vacuumed out during boiler outages. In one case, the piles were broken up and scattered on the duct floor, with the expectation that the sorbent/ash would be re-entrained and transported into the fabric. At no time did these deposit formations impede operation of the unit or require any special operations except for their eventual removal.

There were more serious impacts on the operation of the FFDC. During the period from October 19 to October 20, 1993, the duct injection/humidification system was operated on a 24-hour per day basis to accommodate the air toxics tests, and approximately four days of single shift operation at a 30°F approach to adiabatic saturation temperature. At the end of this period, after the humidifier was turned off, however, the FFDC cleaning became erratic. The FFDC pressure drop would not clean below 4 inches H_2O (normally the FFDC would clear down to a pressure drop of 2.0 inches H_2O) and essentially went into a continuous cleaning mode at full load operation.

The exact onset of the problem was not clear because of the cyclic load operation of the boiler. Effects could only be noted at sustained full load operation when the FFDC pressure drop was at its highest. However, it was clear that the problem started with the resumption of calcium sorbent injection and humidification to a 30°F approach to adiabatic saturation temperature. Examination of the pressure drop data indicated that the bags were not being cleaned effectively and that the post-cleaning pressure drop was higher. Inspection of a couple of FFDC compartments revealed that large accumulations of ash remained in the bags despite cleaning.

Bag samples were removed and sent out for analysis. The level of ash agglomeration was found to be severe on the lower sections of the bags, however, deposits were present over the entire length of the bag. The nodular nature of the deposits was ascribed to moisture being absorbed by the hydroscopic calcium salts. The inability to clean the deposits with the reverse air system is thought to be due to fiberglass fibers, from the bags, being encapsulated by the deposits. Analysis of the bag material itself showed no chemical or thermal degradation.

However, the impact on full load operation was severe enough to require immediate improvement in bag cleaning. A single compartment was isolated and each bag was mechanically cleaned by hand. This was done by lowering each bag, which broke up the cake to a point that it separated from the fabric. After dropping a bag, it was rehung. Manual cleaning of all 12 compartments required two months (November and December 1993) to complete. This cleaning effort restored the performance of the FFDC to a full load (100 MWe) pressure drop of 1.4 to 1.6 inches H_2O after a cleaning cycle, which was an improvement relative to the 2.0 inches prior to humidification. Historical sample bag weight data also confirms the baseline, degradation after humidification, and improvement after the manual cleaning.

The question still remains as to whether the deposition on the bags occurred because of steady state operation of the unit at a 30°F approach to adiabatic saturation temperature, or whether transient effects caused the problems. The fact the FFDC inlet thermocouple grid had measurement problems indicates that unvaporized water was still present.

On the other hand, the wet bag problems could be due to the humidification control system. The current control system adjusts the water flow rate to maintain an average temperature set point. When the boiler load decreases, the water injection rate may be too high for a short period of time until the thermocouple grid responds, resulting in the bags becoming wet. Inspection of the walls of the FFDC compartments indicated areas of rust, suggesting water condensation ran down the walls.

At this point, it is difficult to confidently conclude which of the above mechanisms led to the operational problems with the FFDC.

5.5.3 Economizer Injection Test Results

Previous pilot-scale testing has shown that $Ca(OH)_2$ injection in the temperature range of 1000°F has the potential of achieving SO_2 removals near 20 - 50 percent at a Ca/S ratio of 2.0. The results of the economizer injection tests at Arapahoe Unit 4, beginning with a description of some point-by-point gaseous traverses, followed by a discussion of the effects of Ca/S ratio and humidification.

5.5.3.1 SO_2 Removals

Initial tests at a Ca/S ratio of 2.0 without humidification resulted in SO_2 removals (measured at the outlet of the FFDC) of only 5 to 10 percent. Point-by-point gaseous traverses at the economizer exit showed that the distribution of sorbent was very poor, and only approximately one-third of the flue-gas was being treated. Although SO_2 removals of 30 percent were measured near the east and west walls where the injectors were located, the local Ca/S ratio in this area was estimated to be on the order of 6.0. Longer injectors were installed in three of the four ports on the west side of the boiler in an effort to improve the distribution of sorbent in that area. Figure 5-9 shows the results of the point-by-point traverses for two original injector tests and one with the longer

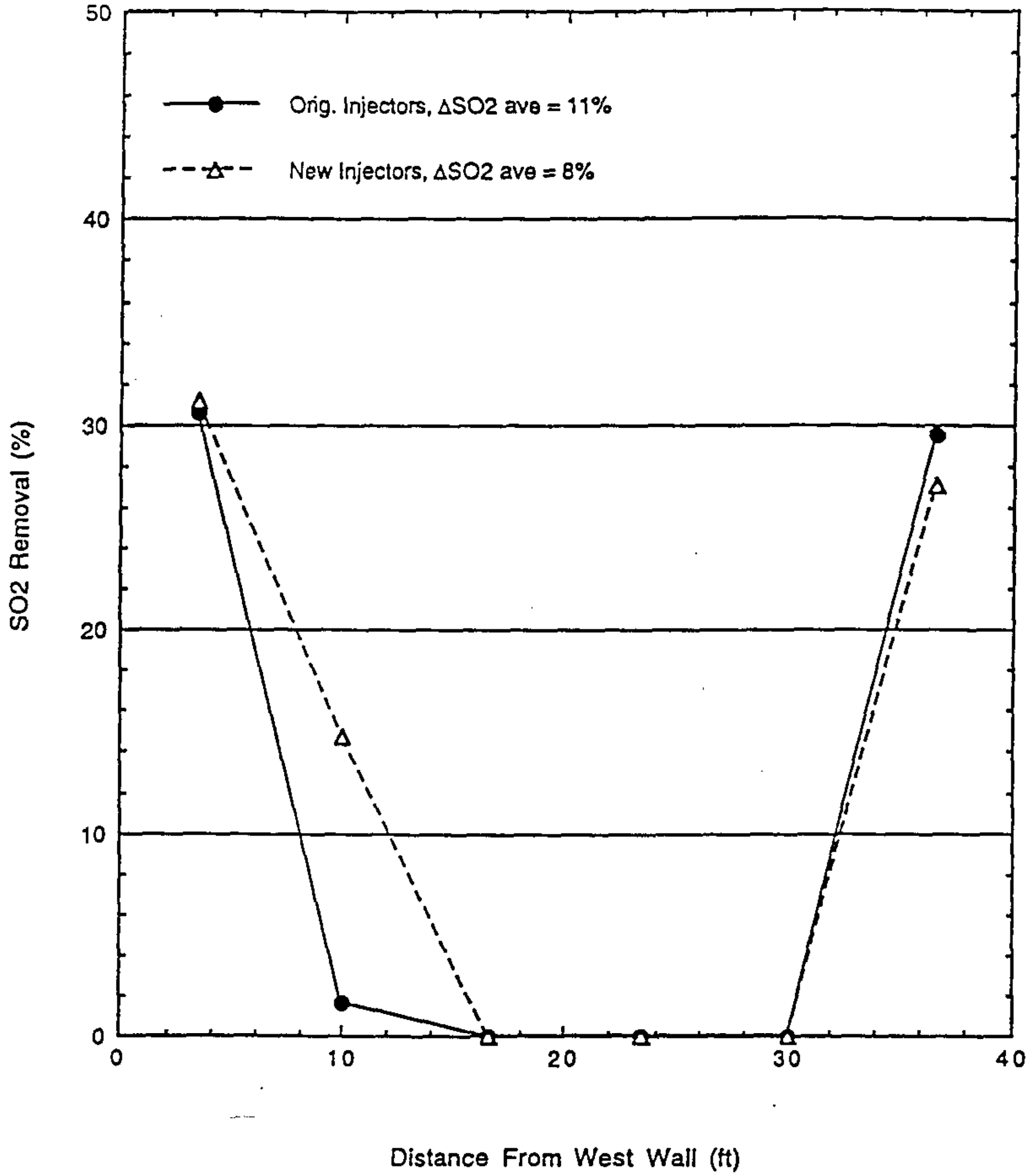


Figure 5-9. Point-by-Point SO_2 Removals with Economizer Injection (80 MWe, Ca/S = 2.0)

injectors on the west side. Both tests were conducted at a boiler load of 80 MWe and a Ca/S ratio of 2.0.

The new injectors improved the distribution of sorbent on the west side of the boiler, however, the improvement was not large enough to result in a meaningful increase in the overall SO_2 removals.

5.5.3.2 Effect of Humidification

Operation of the humidification system during economizer injection was shown to increase the SO_2 removals only slightly. At adiabatic approach to saturation temperatures of 30 and 43°F, humidification increased the SO_2 removals by 3 to 4 percentage points. All of the tests were conducted with injection from both the east and west sides with the original injectors and at a Ca/S ratio of 2.0. There is little effect of boiler load on SO_2 removal, since the flue-gas temperatures at the injection location remained between 950 to 1150°F over the load range of 70 to 115 MWe.

5.5.3.3 Solids Analysis

To determine the reason for the low SO_2 removal efficiencies with economizer injection and humidification, a sample of the sorbent/fly ash mixture was obtained from the east air heater exit duct, just upstream of the humidification grid, where the sorbent-to-fly ash ratio was highest. A chemical analysis indicated that approximately 63 percent of the calcium in the sample was in the form of $CaCO_3$, and therefore, unreactive with SO_2 and humidification. $Ca(OH)_2$ accounted for approximately 32 percent of the total calcium, and the remaining 5 percent was CaO. At economizer injection temperatures, the sulfation reactions compete with carbonation and dehydration of the $Ca(OH)_2$. It is apparent, that the high carbonate fraction limited SO_2 removal at the economizer, and, that the low availability of unreacted $Ca(OH)_2$ limited the possibility of further SO_2 removal with humidification. Additional analyses showed that the economizer injection sorbent/fly ash mixture had a significantly higher level of sulfite than sulfate in the samples.

These results are consistent with the current understanding of the economizer injection process which indicates $CaSO_3$ to be the expected product.

5.6 Environmental Performance of Calcium-Based DSI

This section summarizes the *Environmental Monitoring Report: Calcium-Based Dry Sorbent Injection.* Environmental monitoring was completed according to the *Environmental Monitoring Plan for the Integrated Dry NO_X/SO_2 Emissions Control System*, dated February 1992 and its addendum dated July 1993.

Generally, the testing went well and there were no significant environmental events during the test period and there were no excursions of any compliance requirements during testing. A significant amount of supplemental monitoring was completed to determine the emissions while operating and testing the DSI system with calcium-based reagents. The major environmental affect of the calcium injection system was the decrease in the SO_2 emissions and a change in the waste characteristics. The waste characteristics and effects on various liners is discussed along with the sodium injection waste in section 4.6.2 of this report.

Additional supplemental monitoring to collect data for 21 potential air toxics was completed during the calcium injection testing. Sampling for this testing was conducted October 19 and 20, 1994. Additional baseline testing to determine a number of dioxins and furans was also conducted without the calcium injection system in operation. This baseline sampling was conducted October 11, 12, and 13, 1993. The results of the air toxics testing during calcium injection were similar to the results of the other air toxics test programs. Trace metals removal was very high at 98.6%. The major difference from other testing was an increase in mercury removal to over 93%. Fluoride and chloride removal was also much higher than the other test programs. It is believed the humidification system and flue gas cooling was responsible for the increased reductions. A complete summary of the results is contained in Appendix H

6 INTEGRATED SYSTEM

This section describes the Integrated Dry NO_x/SO_2 Emission Control System. It first describes the interaction of the emissions control systems, then the objectives, methodology, and results of the test program. Final Report, Volume 1: Public Design describes the design and operation of the integrated system in more detail.

6.1 Technology Description

The integrated system consists of the LNBs, OFA ports, SNCR system, and the DSI system (sodium-based reagents). The combined technologies of the Integrated Dry NO_x/SO_2 Emissions Control System were expected to integrate synergistically and control NO_x and SO_2 emissions better than if each technology were used alone. The following sections describe the synergistic interaction of the technologies.

6.1.1 Integration of Low-NO_x Combustion System and SNCR

LNBs and OFA ports reduce the NO_x produced by combustion. This reduction enhances the effectiveness of the SNCR system. With a lower initial level of NO_x, the SNCR system was expected to require less urea to create less ammonia slip.

6.1.2 Integration of SNCR and DSI

Although sodium-based DSI systems reduce the emissions of SO_2, some applications have caused NO to convert to NO_2. Because NO_2 is a brownish-orange gas, the formation of NO_2 can cause a visible plume to form as the flue gas exits the stack.

It was expected that the combination of urea injection and sodium-based DSI will improve the performance of both systems. Previous tests have shown that ammonia reduces the formation of NO_2 in sodium-based DSI systems and removes the ammonia that would have exited the stack.

6.1.3 Integration of Low NO_x Combustion System and DSI

Most of the NO_x produced by combustion is NO; less than 5% of it is NO_2. The low-NO_x combustion system produces less of both NO and NO_2. As the low-NO_x combustion system greatly reduces the NO baseline, the DSI system has less NO to convert to NO_2. With a lower NO_2 baseline, the DSI system is able to form more NO_2 before a visible plume appears. Therefore, the integration of the low-NO_x combustion system with DSI was expected to allow the DSI system to achieve higher rates of SO_2 removal.

6.1.4 Project Proprietary and Patent Information

The Integrated Dry NO_x/SO_2 Emissions Control System is a combination of existing technologies that work synergistically to provide higher SO2 and NOx removals. The individual technologies may or may not be patented individually. However, the specific integration of urea -based SNCR in combination with sodium-based dry sorbent injection was issued patent number 5,165,903 by the U.S. Patent Office on November 24, 1992.

6.2 Integrated System Test Program Objectives

The objectives of the integrated systems test program were twofold. The first objective was to document that the combined low NOx burner, overfire air, SNCR, and sodium-based DSI system when operated together could simultaneously achieve the project goals of 70% NO_x removal and 70% SO_2 removal.

The second objective of the integrated test program was to demonstrate the synergistic benefits of integrating SNCR with sodium-based DSI discussed above. Specifically, *having the NH_3 slip from the SNCR slip reduce the NO_2 produced by the sodium/SO_2* reactions; and conversely the sodium system reduce NH_3 emissions from the SNCR system.

6.3 Integrated System Test Program Methodology

6.3.1 Instrumentation

The instrumentation used during the integrated test program was identical to the instrumentation used to characterize the individual technologies.

6.3.2 Test Methods

The test methodology for the integrated tests was similar to the individual technology test programs involving both parametric and long-term test phases. The parametric tests were run over the course of a single day, where the boiler load was held constant and both the DSI and SNCR control systems were run manually (i.e., at fixed 2Na/S and N/NO ratios). If the goal of the test was to determine the reduction in NO_2, the DSI system would be started first and allowed to stabilize. The SNCR system would then be started and the impact on NO_2 measured. To parametrically assess the effect of the DSI system on NH_3 slip, the test sequence would be to first start the SNCR system, followed by the DSI system after the SNCR system had stabilized.

Ideally, it would have been desirable to parametrically evaluate the merits of the integrated system over a range of operating conditions. This was not entirely possible for a number of reasons. With sodium-based DSI, NO_2 levels were found to be not only dependent on the amount of sodium injected, but also dependent on the particulate in the FFDC and the cleaning intervals. Also, the time required for NH_3 levels to stabilize at the exit of the FFDC, both before and after sodium injection, was greater than the 10-hour a day period during which the load from Arapahoe Unit 4 could be blocked. Thus, characterizing the integrated performance relied on a limited number of parametric tests followed by a series of "long-term" tests under normal load following conditions. During these "long-term" tests, the NO_x reduction and SO_2 removal systems were operated in automatic while the unit was operated according to system dispatch requirements. Data were collected at regular intervals using a data logger. No effort was made to set up specific test conditions, as these tests were designed to simulate operation of these systems once they are turned over to the plant at the completion of this program. Two long-term test series were conducted. The first long-term tests series was conducted using NOELL's ARIL lances incorporated into the SNCR system (Smith, et al., 1996). A nominal two week long-term test series was also conducted using the alternate DPSC lances as part of the SNCR system.

6.3.3 Quality Control/Quality Assurance

The same quality assurance methods were used during these integrated tests as were used for the individual technology test programs.

6.4 Integrated System Test Program Results

6.4.1 Parametric Test Results

This subsection will provide an overview of the parametric test results of the integrated system. The reader is referred to the report by Smith, et al., 1996; that documents all of the parametric tests.

Figure 6-1 shows the results of one of the first integrated parametric tests. This test was conducted using sodium bicarbonate injection ahead of the FFDC. For this test, the DSI system was started first and the SNCR system started after the DSI system had been on for five hours. Two observations are noteworthy. First, the sodium SO_2 reaction rates are slow with sodium bicarbonate injection ahead of the FFDC, almost five hours were required to reach steady state. Again, the slow reactions between sodium bicarbonate and SO_2 is due to the relatively low flue-gas temperatures through the FFDC. The data shown in Figure 6-1 was collected at a load of 95 MWe with a FFDC temperature of 250°F. The key observation in Figure 6-1 is the dramatic drop in NO_2 when the SNCR system was turned on 5 hours into the test. Prior to starting the SNCR system, the NO_2 levels had reached 45 ppm with sodium bicarbonate injection alone. After the urea injection system was started, the NO_2 levels dropped to under 5 ppm. These test results clearly illustrate the potential reduction in NO_2 by operating the integrated system.

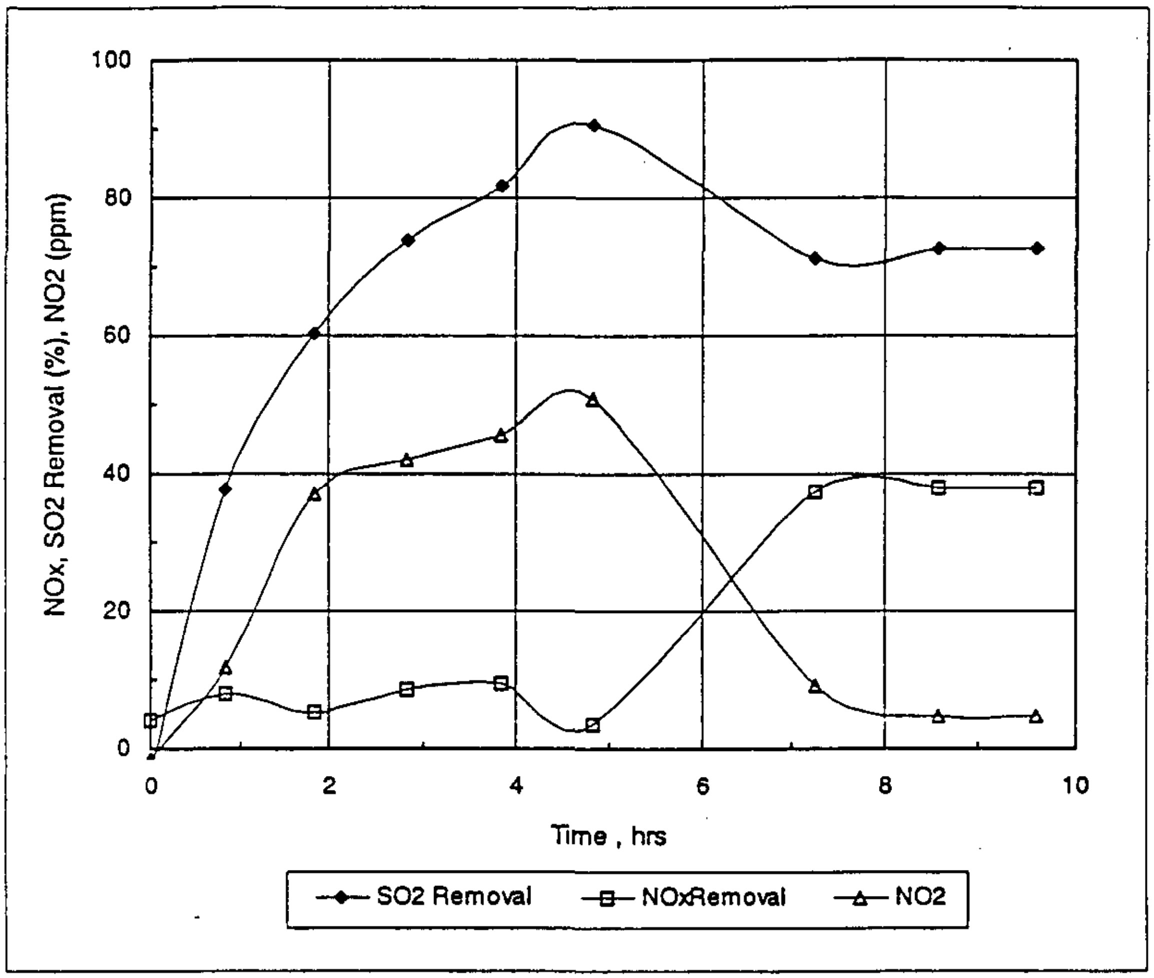


Figure 6-1. Parametric Integrated Test with Sodium Bicarbonate Injection ahead of the Fabric Filter (Load: 95 MWe, 2 Na/S = 1.0, N/NO = 1.0, $T_{BH} = 250^{\circ}F$)

The results of a parametric test with sodium sesquicarbonate injection and the SNCR system are shown in Figure 6-2. During these tests, the DSI system was again started first, followed by the SNCR system. For this test, the DSI system was set at an NSR of 2.0 and the SNCR system at $N/NO_x = 0.6$. Following the start of the DSI system, the SO_2 removal stabilized at nominally 70% removal and the NO_x removal at 12%. This level of NO_x removal is consistent with previous tests of the DSI system alone. The NO_2 levels increased to only about three ppm at the point that the SNCR system was started. With the SNCR system started, the NO_x removal increased to 35 to 40% and the NO_2 levels remained constant at three ppm. Even following a FFDC cleaning cycle, the NO_2 levels did not increase with the SNCR system in operation. Just before 1800 hours, the SNCR system was turned off and an immediate increase in NO_2 was noted.

Figure 6-3 shows the results of a parametric test with sodium bicarbonate injection ahead of the air preheater. With sodium bicarbonate injection alone at an NSR of 1.1, NO_2 levels were on the order of 50 ppm. For the test results shown in Figure 6-3, the SNCR system was started at N/NO = 1.1 nominally two hours before the DSI system. As can be seen, the NO_2 levels remained near zero for the entire test. Further, it can be seen that following the start of the DSI system, the NH_3 slip levels continued to decrease.

The results shown in Figures 6-1 to 6-3 clearly show that there is a synergistic benefit of operating the SNCR and sodium-based DSI systems simultaneously.

6.4.2 Long-Term Integrated Tests

Because of the difficulties encountered running the short term parametric integrated tests, the balance of the integrated tests were run under normal load following conditions. During these tests the integrated system was operated 24 hours per day with the DSI and SNCR systems operated in an automatic mode and the system parameters data logged. Also these long-term tests were conducted using sodium sesquicarbonate injection ahead of the FFDC. Before presenting the results, it is of value to briefly review the automatic control modes for the system and how the data can be interpreted.

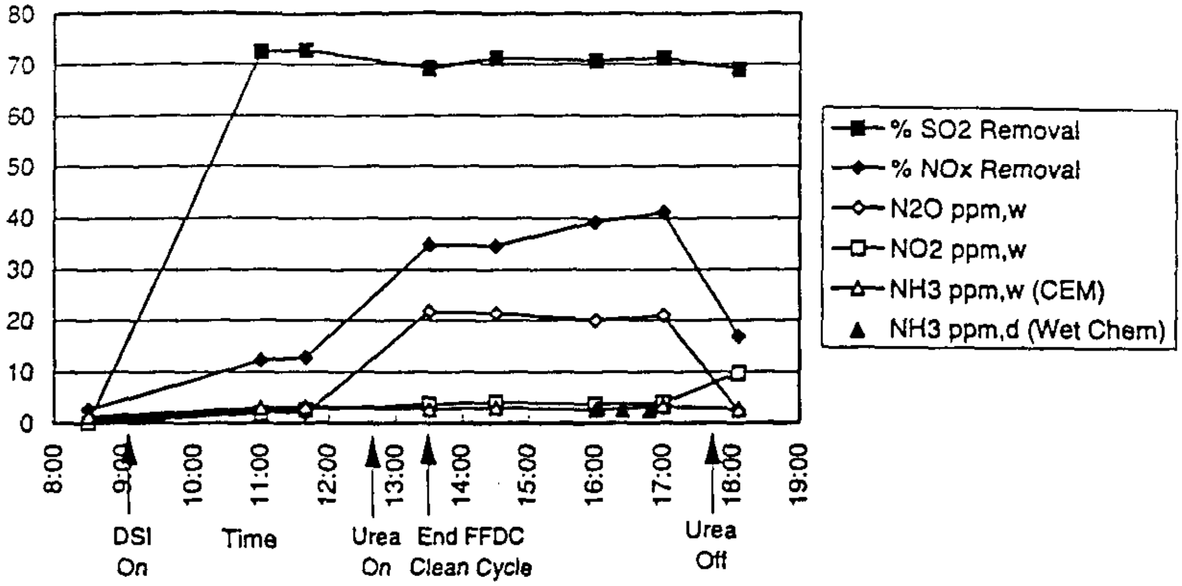


Figure 6-2. Time History of 100 MWe Integrated Test with Sodium Sesquicarbonate Injection (2Na/S = 2.0, N/NO$_x$ = 0.6, A Mill OOS)

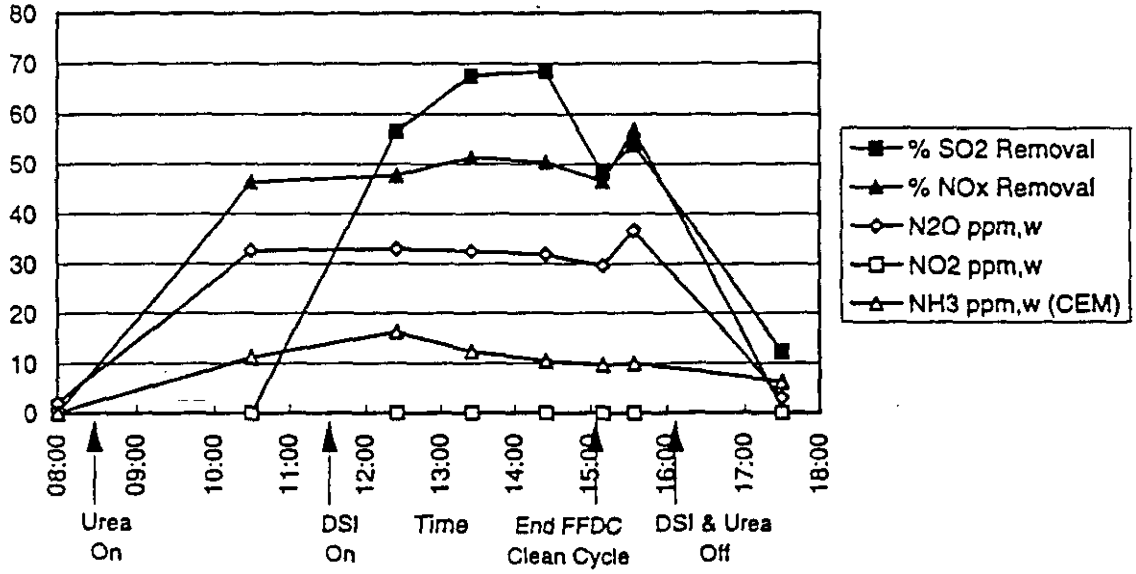


Figure 6-3. Time History of Integrated Test with Sodium Bicarbonate Injection (2Na/S = 1.1, N/NO$_x$ = 1.1, 100 MWe, 4 Mills in Service)

DSI System: In automatic control, an SO_2 removal setpoint is input to the control system. The SO_2 removal is measured by the CEM which time-shares between sampling locations at the inlet and outlet of the FFDC. The control system adjusts the sodium injection rate to maintain the SO_2 removal set point. The control system also has a trim system that will reduce the sodium injection rate if the NO_2 levels exceed a set point value (for these tests, the NO_2 set point was 20 ppm). With this control system, any *changes in the SO_2 removal process of the DSI portion of the integrated system will be manifested in the sodium injection rate.*

SNCR System: With SNCR, it is not possible to measure the NO_x concentration ahead of the urea injection and calculate the NO_x removal. Thus, the SNCR system uses a prescribed urea injection rate as a function of load. The control system also incorporates an NH_3 trim control. If the NH_3 concentration at the exit of the FFDC is less than the NH_3 trim setpoint the control system increases the urea injection rate. Conversely, if the NH_3 slip exceeds the setpoint, the control system decreases the urea injection rate. The urea injection rate versus load set points were established during the SNCR only tests so as not to exceed a 10 ppm level of NH_3 slip. This is important in that if the integrated system reduces NH_3 slip, it will show up as a higher urea injection rate than the prescribed set point.

The long-term tests were performed in two phases. The majority of the long-term tests were performed in the first phase and documented in the report by Smith, et al., 1996. During this first phase, the SNCR utilized the back wall, Level 1, injectors and NOELL's ARIL lances. The final phase of long-term integrated tests comprised a nominal two week period in November 1996. During this second phase, the SNCR system used the DPSC lances in place of the ARIL lances.

6.4.2.1 Integrated Long-Term Tests with the ARIL Lances

This subsection will show representative data collected during the long-term tests. The reader is referred to the report by Smith, et al., 1996, for more complete documentation of the long-term integrated tests with the ARIL lances. Figures 6-4 and 6-5 show representative data collected during the long-term tests for two days (February 29, 1996 and March 4, 1996), respectively.

Figure 6-4 shows the data collected over a 24-hour period on February 29, 1996. During these tests, the integrated system was utilizing sodium sesquicarbonate injection ahead of the FFDC, and the SNCR system was load following with both the wall injectors and ARIL lances. On this day, the boiler load was nearly constant for the first 17 hours of the day. The N/NO_x ratio and NH_3 emissions were also relatively steady during this time. At 1600 hours, the DSI system was started with a 75 percent SO_2 removal setpoint with the hope that the load would remain steady and it would be possible to assess the beneficial effects of running the integrated system. Although the load increased significantly about two hours after the DSI system was started, it eventually settled back down to a level similar to the level before the increase. Figure 6-4 shows that the average NH_3 emissions with and without sodium injection were similar, which was expected since the NH_3 trim control was functioning during both of these tests. However, the results also show that there was a substantial increase in the N/NO_x ratio. Since the SNCR control system was set to maintain the NH_3 emissions within the range of 7 to 8 ppm, it should have increased the urea injection rate if the DSI system reduced NH_3 emissions. A temporary increase was expected as a result of the load swing, but the N/NO_x ratio should have returned to the pre-swing level within two to three hours (as was seen after the morning demand peak between 0800 and 0900 hours). When the DSI system was started at 1600 hours, there was an immediate 10 percent increase in the NO_x removal, which is consistent with the increases seen during sodium-based DSI-only tests. After this initial NO_x removal increase, there was another slower increase (amounting to nominally 10 to 15 percent removal) which occurred as the N/NO_x ratio increased. Although the scaling of the data makes it difficult to see, Figure 6-4 indicates that the N/NO_x ratio basically doubled after the DSI system was started. The increase in N_2O emissions (from nominally 8 to 16 ppm), confirms that the N/NO_x ratio was increased by roughly a factor of two. These results clearly indicate that there was a substantial reduction in the stack NH_3 slip, when the SNCR and DSI systems were run concurrently.

Figure 6-5 shows data collected during the 24-hour period on March 4, 1996. The DSI system was operated for the entire period and the SNCR system was started at 1420 hours. The boiler load was fairly steady at this time, and was low enough for the control system to insert the ARIL lances. Although the DSI feedrate was not very consistent, Figure 6-4 shows that there was nominally a 50 percent reduction in the NO_2 emissions when urea injection began. The load remained steady for nearly four hours; then it increased for the usual "evening demand peak" at 1800 hours. When the lances retracted, the N/NO_x ratio dropped as demanded by the control system, and the NO_2 emissions were also seen to decrease. By 1900 hours, the NO_2 emissions had been reduced to near-zero levels. This effect is due to the difference in the NH_3 emissions between injection at the Level 1 and ARIL locations. Although effort was made to set up the SNCR control system such that the NH_3 slip was limited to 10 ppm throughout the load range, the Level 1 location is "cooler" overall than the ARIL location; thus injection at Level 1 is more sensitive to variations in the flue-gas temperature profile. Therefore, in general, urea injection at the Level 1 location results in higher NH_3 slip levels at the FFDC inlet. Since the NH_3 emissions are generally higher with urea injection at the Level 1 location, it would be expected that the reduction in stack NO_2 emissions would also be higher (relative to injection at the ARIL location). The hypothesis is further supported by the decrease in NO_2 emissions seen when the urea injection switched from the ARIL lances to Level 1 at 1800 hours in Figure 6-5; and also by the increase in NO_2 seen when the lances were reinserted at 2000 hours. When the lances went in at this time, the NO_2 emissions were essentially zero. After an hour, however, the NO_2 emissions slowly began to increase, finally leveling out at approximately 8 ppm.

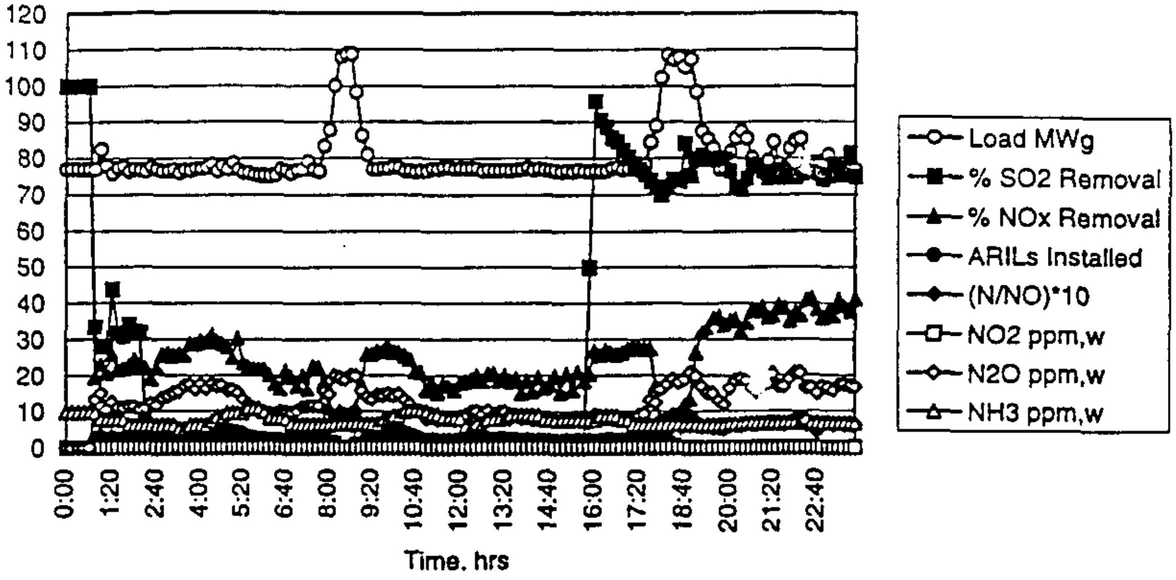


Figure 6-4. Long-Term Integrated Load-Following Test Results with ARIL Lances (February 29, 1996)

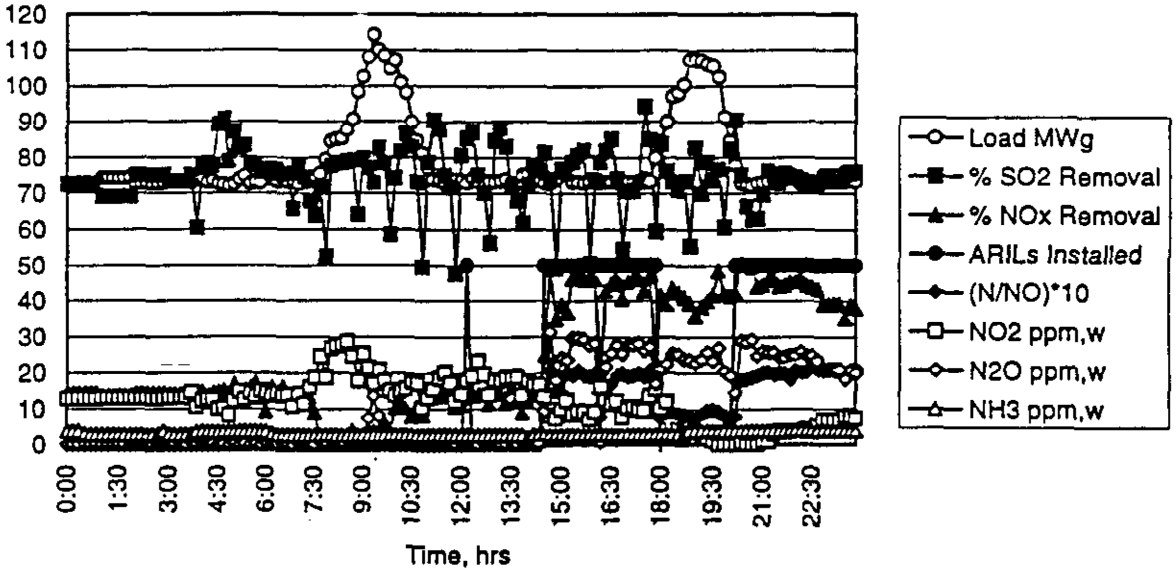


Figure 6-5. Long-Term Integrated Load Following Test Results with ARIL Lances (March 4, 1996)

The previous discussion presented the long-term data in a chronological format. This presentation format illustrated the dynamic behavior of the system and the discussion pointed out some of the interactions of the SNCR and DSI systems. These interactions can be better illustrated by cross plotting some of the long-term data and comparing the overall average performance. These cross plots and averages were constructed using 10 minute average data from the CEM for the period February 19, 1996, through March 14, 1996.

Before presenting these summarized results, it should be noted that these plots are based on the long-term data from the CEM. As such, it includes periods of transient boiler operation and transient operation of the SNCR and DSI systems, so the data will exhibit more scatter than the parametric tests.

Figure 6-6 shows the NO_2 emissions as a function of load for time periods when the DSI system was operated alone and for the integrated operation of the system. Again, while

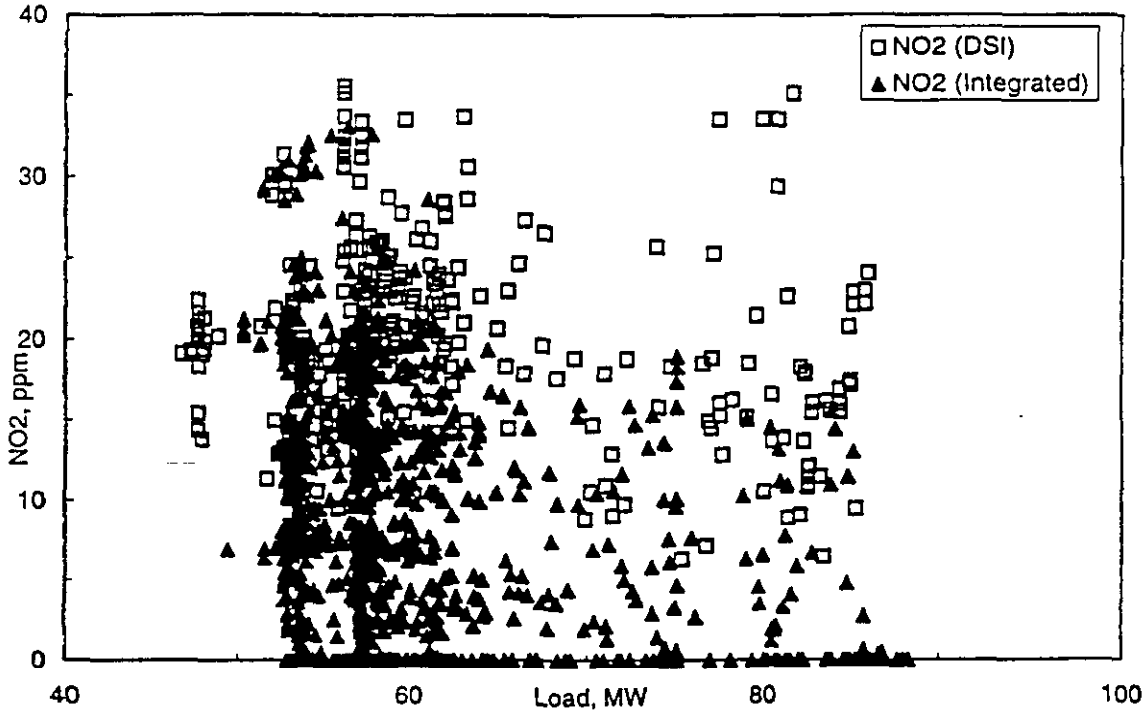


Figure 6-6. Long-Term System Operation: NO_2 Emissions Versus Load

there is scatter in the data, Figure 6-6 clearly illustrates that the NO_2 emissions are lower when the integrated system is operated. With the sodium-based DSI system operating alone, the NO_2 levels ranged from nominally 10 to 35 ppm. For the majority of the time with the integrated system, the NO_2 levels were less than 10 ppm. In fact, taking a simple arithmetic average, the NO_2 levels with the DSI system alone were 20 ppm, and were only 8 ppm with the integrated system.

The advantages of the integrated system are clearly shown in Table 6-1. As discussed above, the NO_2 levels were less than half those when operating the DSI system alone. This decrease in NO_2 is again due to the interaction between the NH_3 slip from the SNCR system and the sodium/SO_2 chemistry in the FFDC.

	Integrated System	SNCR Only	DSI Only
SO_2 Removal, %	76	--	74
NO_x Removal, %	34	23	
N/NO Ratio, Molar	0.74	0.72	
NH_3 *Slip, ppm*	5	9	
NO_2, ppm	8		20
ARIL Lances			
N/NO Ratio, Molar	2.03	1.27	
NO_x Removal, %	40	33	
NH_3 Slip, ppm	4	8	
Level 1 Injectors			
N/NO Ratio, Molar	0.46	0.43	
NO_x Removal, %	33	18	
NH_3 Slip, ppm	5	10	

Table 6-1. Summary of the Integrated Long-Term Tests (ARIL Lances)

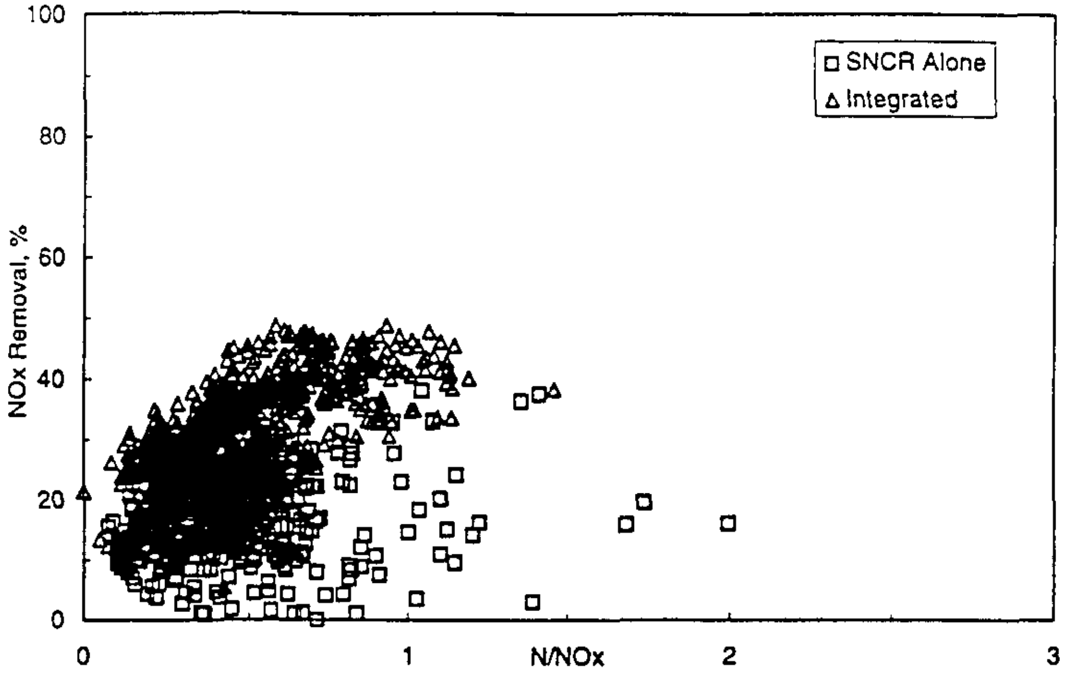
Considering the overall performance for the period from February 19, 1996 through March 14, 1996, the integrated and SNCR-only periods averaged about the same overall N/NO ratio. However, the NO_x reduction with the integrated system was 11 percentage points higher due primarily to the NO_x removal, which occurs during the sodium-SO_2 chemistry. More importantly, the NH_3 slip with the integrated system was about half that of the SNCR only test periods and the NO2 formation with the integrated system was less than half of the DSI only test periods.

These interactions can be seen more clearly by looking at the integrated system performances during periods when the ARIL lances and Level 1 injectors were being used. As seen in Table 6-1, with the ARIL lances the SNCR system was able to operate at a considerably higher N/NO ratio in the integrated mode (N/NO of 2.03 compared to 1.27 for the SNCR system alone). Yet the ammonia slip was one-half of the SNCR-alone periods. The DSI system reduces the ammonia slip for a given urea injection rate and the automatic control system responds by increasing the urea injection rate. During this long-term test period, the Level 1 injectors operated at about the same N/NO ratio during both the integrated and SNCR-alone periods. But, again, the ammonia slip is half during the integrated test periods.

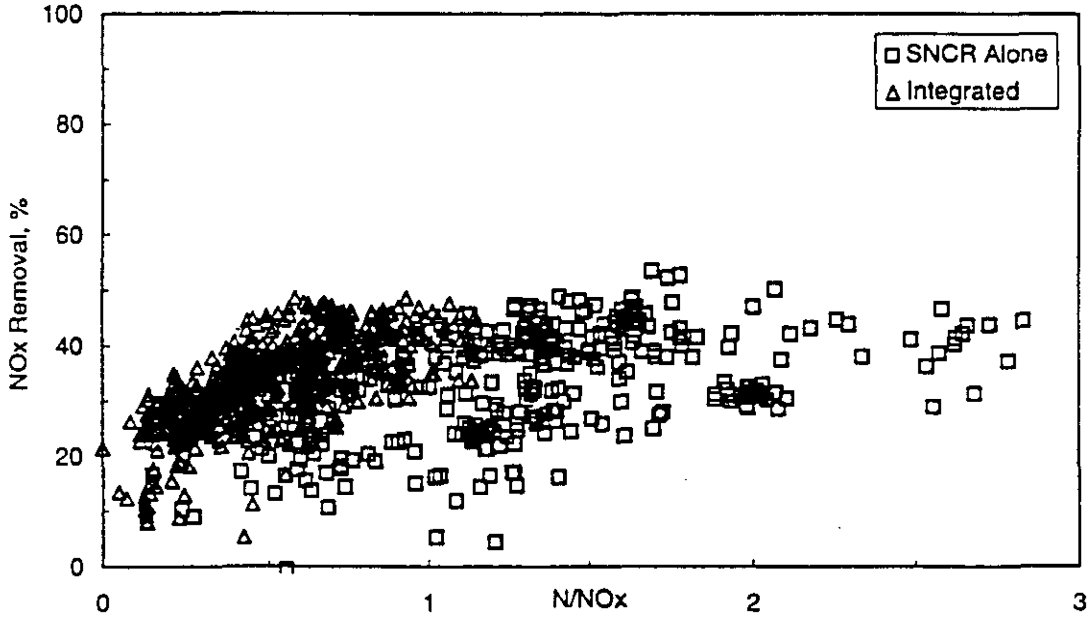
Figure 6-7 compares the NO_x removal with the integrated system compared to the SNCR system alone. Part (a) of Figure 6-7 shows results with the Level 1 injectors and Part (b) of Figure 6-7, the results when the ARIL lances are in service. For both injection systems, the NO_x removals with the integrated system are about 10 percentage points higher than with the SNCR system alone. This increase in NO_x removal at a given N/NO ratio can be partially attributed to the NO_x removal that occurs with the sodium system in the FFDC.

6.4.2.2 Integrated Long-Term Tests with the DPSC Lances

Following the parametric tests of the DPSC lances, the system was operated in automatic during the period from November 19, 1996 through December 9, 1996. During this time period, CEM and process data was collected for 329 hours. Figure 6-8 shows the dynamics of the system performance over the 24-hour period on November 21, 1996. DPSC lances were inserted from 0000 hours until 0610 and then again from 1130 - 1620 hours. During this 24-hour period the sodium injection system maintained the SO_2 removal at nominally 55%. Just before 0200 hours, urea injection was turned off for about two hours. With the urea turned off, the NO_2 increased from essentially zero to about 6 ppm. When the urea injection was restarted, the NO_2 decreased to near zero. The increase in NO_2 just before 1400 hours corresponds to a FFDC cleaning cycle.



(a) Level 1 Injectors



(b) ARIL Lances

Figure 6-7. Comparison of NO_x Removal for the Integrated System and SNCR System Operated Alone

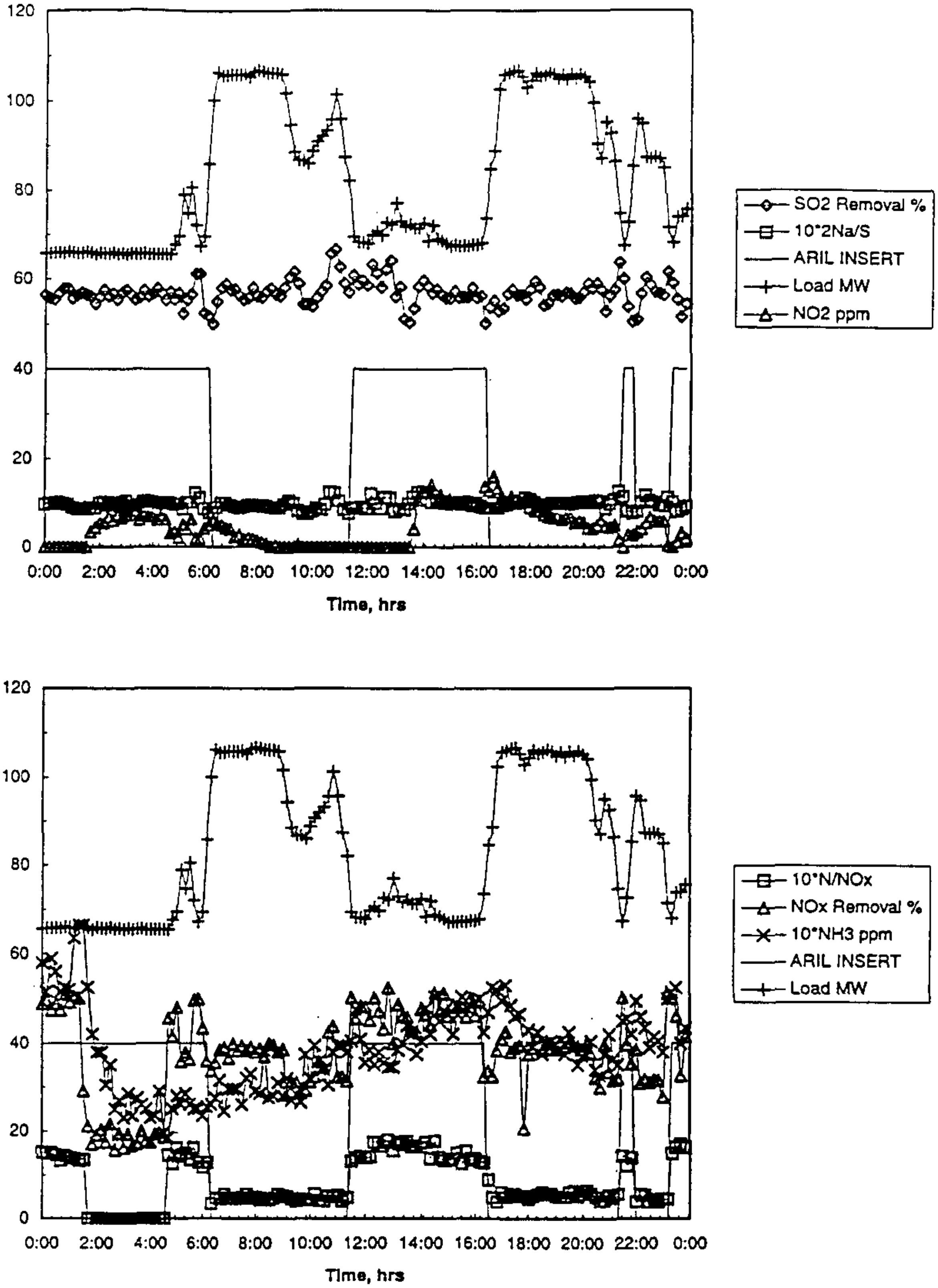


Figure 6-8. Integrated System Performance with the DPSC Lances (November 21, 1996)

Also with the urea turned on, the DPSC and Level 1 injectors were able to maintain the NO_x removal at an average of 40 percent. Note, that during the long-term tests, it was not possible to turn the SNCR system off in order to obtain a baseline NO_x value. Thus the initial, or "baseline", NO_x values used to calculate the NO_x removal are based on a curve fit to NO_x versus load data without the SNCR or DSI systems operating. Thus, there may be some differences in the N/NO ratio and NO_x removal relative to a parametric test where all parameters are measured explicitly.

Table 6-2 summarizes the overall average performance of the integrated system incorporating the DPSC lances. During this period, data was collected for nominally 329 hours (the system was not operated over the Thanksgiving Holiday). As with the previous long-term tests (incorporating the ARIL lances), the integrated system was able to operate at a higher N/NO ratio, with nominally the same level of NH_3 slip. This was particularly true for the DPSC lances which inject into a higher temperature region of the furnace. The combination of the higher average N/NO ratio along with the NO_x removal that occurs with the sodium system results in a higher overall NO_x removal than the SNCR system alone.

Total Data Collection Time:	329 hours			
Sodium Injected:	86%			
Urea Injected:	53% (85% with sodium, 15% without sodium) (DPSC lances 21%, Level 1 Injectors 79%)			
DSI Performance				
2Na/S:	0.81			
SO_2 Removal:	45%			
SNCR Performance	Integrated System		SNCR Alone	
	DPSC	Level 1	DPSC	Level 1
N/NO:	1.51	0.64	1.12	0.53
NO_x Removal:	42%	24%	34%	18%
NH_3 Slip	2 ppm	4 ppm	3 ppm	2 ppm

Table 6-2. Summary of the Long-Term Integrated Tests with DPSC Lances (November 19 - December 9, 1996)

6.4.2.3 Ammonia Absorption on the Fly Ash

An issue that needs to be addressed with any post-combustion NO_x reduction technology with NH_3 slip is the absorption of ammonia on the fly ash. This can have a number of impacts ranging from personnel safety while handling the ash, odor problems, or impacting the salability of the ash for future use as a cement aggregate. In the latter, a nonsalable product becomes a disposal problem with an attached economic penalty. At the Arapahoe Station, the ash is not sold for use in cement. Thus, the only problems that have been encountered have been an occasional NH_3 odor around the ash handling area and potential concern with worker safety should the concentrations become too high.

At Arapahoe Unit 4, ash is removed from the FFDC hoppers with a vacuum system and transported dry to an ash silo. When loaded onto trucks for transport to the disposal site, the ash is wetted with about 20% water (by weight) in order to minimize fugitive dust emissions. Depending upon the specific ash characteristics, this wetting process can result in the release of NH_3 vapors from the ash. Whether or not NH_3 is released from the ash depends primarily on the pH of the aqueous phase on the surface of the ash particles. As the pH increases above a level of 9 to 9.5, there is an increased release of vapor-phase ammonia.

During the test program with urea injection alone, the ammonia concentration in the ash varied over the range of 100 to 200 ppm (measured on a weight basis). The ash ammonia content appeared to be primarily related to the NH_3 slip levels from the SNCR system and, to some extent, the FFDC cleaning cycles. During long-term testing with the SNCR system alone, and a 10 ppm NH_3 slip limit at the stack, there were no incidents of excessive NH_3 odors during the ash handling process.

Testing has shown that when the SNCR system is operated in conjunction with the dry sodium injection system, the urea injection rate could be increased substantially while maintaining a 10 ppm NH_3 slip level at the stack. This is one of the synergistic benefits of the patented Integrated Dry NO_x/SO_2 Emissions Control System discussed above.

However, during these tests, the ammonia concentration in the ash increased to the range of 400 to 700 ppm (weight basis), and there were frequent occurrences of NH_3 odors at the ash silo. Reducing the NH_3 slip set point to the range of 4 to 5 ppm reduced the ammonia concentration of the fly ash down to the 100 to 200 ppm range (weight basis), but the odor problem persisted.

At first, it was thought that the odor problem was a result of the sodium changing the pH of the ash. The pH resulting from placing 0.5 gram of ash in 200 ml of distilled water was 9.3 for an ash sample without sodium injection. The same test run with an ash sample from a test with sodium injection resulted in a pH of 10.3. While the sodium did indeed increase the pH, which in turn would tend to release more NH_3 from the aqueous to the vapor phases, the pH difference did not appear significant enough to account for the ash handling problems encountered.

An interesting observation was made during the pH measurements. While the presence of sodium was found to slightly increase the final pH, it was also found to have a large effect on the rate at which the pH changed as the ash was wetted. Figure 6-9 shows the change in pH versus time after 0.5 gram of ash is placed into 200 ml of distilled water and stirred. With the coal ash alone, almost 30 minutes are required for the soluble components of the ash to dissolve and change the pH to a final value of 9.3. However, with sodium present in the ash sample, the pH develops almost instantaneously, presumably because of the higher solubility of the sodium compounds in the ash. This more rapid development of the high pH level can result in more rapid and localized release of the ammonia vapor, and may explain the odor problem encountered when concurrently operating the SNCR and sodium systems. Other than decreasing the level of NH_3 slip from the SNCR system, additional approaches to dealing with this issue have not been explored.

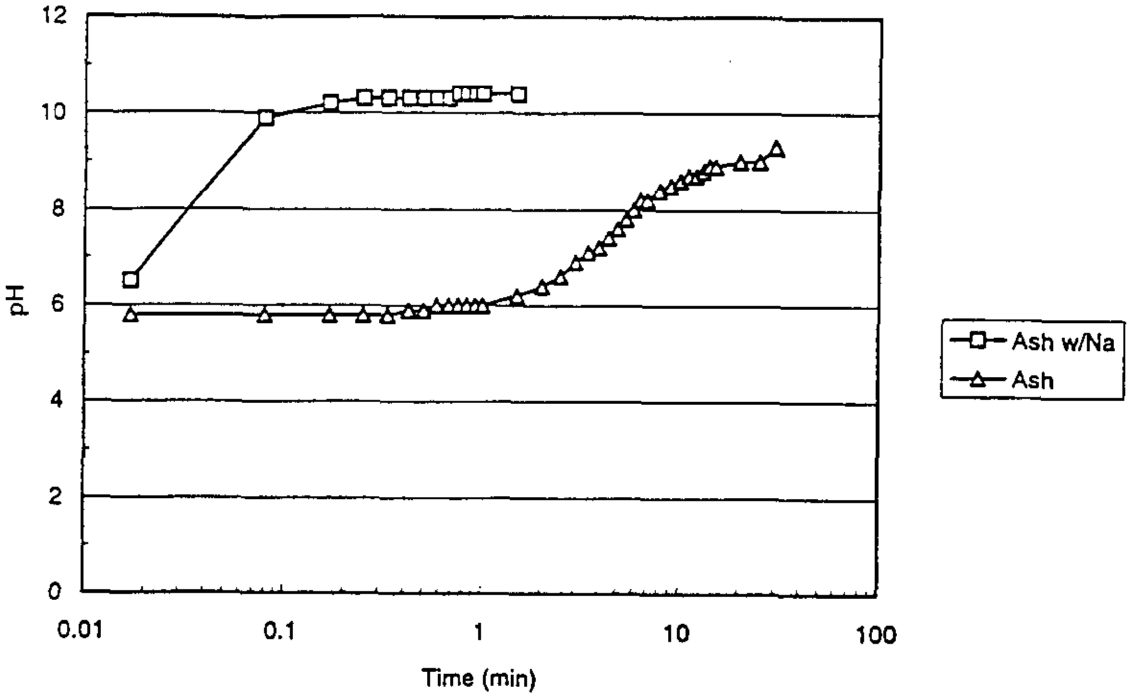


Figure 6-9. pH versus Time for Coal Ash and Coal Ash/Sodium Mixture (0.5 grams of ash in 200 ml of H_2O)

6.5 Summary of the Integrated Tests

The integrated tests have demonstrated the synergistic benefits of simultaneously operating a sodium-based DSI system and an SNCR system:

- NO_2 emissions are dramatically reduced when the sodium-based DSI system is used in conjunction with the urea-based SNCR system.
- Comparably, NH_3 slip from the SNCR system is reduced when the DSI system is in service. (With automatic operation of the system, this is reflected by a higher urea injection rate for a given NH_3 slip setpoint.)
- Without the SNCR system, NO_2 emissions exhibit a large increase following a FFDC cleaning cycle. The SNCR system suppressed this spike, although some increase can be noted.
- Operation of the integrated system (at an 8 ppm NH_3 slip limit) resulted in an odor problem around the ash silo. (This was not encountered with the SNCR system alone.) This is attributed to the solubility of the sodium compounds increasing the release of NH_3 when the ash is wetted for transport.

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7.1 Economic

7.1.2 Total Process Capital Cost

The total process capital cost is the installed equipment cost plus the retrofit and process contingency costs. These costs are calculated as a percentage of the installed equipment cost. Table 7-1 summarizes the guidelines used to estimate these factors.

Retrofit Conditions	**Retrofit Factor**
New (greenfield) plant.	0.0
Interference similar to new plant with adequate work space. Free access for large cranes and adequate space for standard layout of equipment.	0.02
Some aboveground interferences and work space limitations. Access for cranes limited to two sides. Requires placement of some equipment on elevated slabs or in remote locations.	0.10
Limited space. Interference with existing structures or equipment that cannot be relocated. Requires special designs or new major ductwork. Access for cranes is limited to one side. Requires placement of majority of equipment on elevated slabs or in remote locations.	0.25
Severely limited space and access. Crowded working conditions. Access for large cranes blocked on all sides. Requires major modifications of existing equipment.	1.00

Development Status of Technology	**Process Contingency Factor**	
	Normal	**Default**
New concept with limited data.	40^{+}%	70%
Concept with bench-scale data.	30-70%	50%
Pilot-plant data available	20-35%	25%
Full-size module data available.	5-20%	15%
Commercial process.	0-10%	5%

Table 7-1. Guidelines for Total Process Capital Factors

7.1.2.1 Retrofit Cost

The retrofit cost represents the additional cost, compared to a new unit, required to retrofit an emission control system onto an existing unit. It is calculated by multiplying a retrofit factor by the installed equipment cost. The retrofit factors are based on the guidelines shown in Table 7-1. The more confining the site of a unit, the higher the factor. As most of the estimates for the installed equipment costs are based on the retrofit of a system to Arapahoe Unit 4, most systems have a retrofit factor of zero. Thus it assumes that the estimated unit would have the same difficulty of retrofit as occurred at Arapahoe.

7.1.2.2 Process Contingency Cost

The process contingency cost accounts for the state of development of an emissions control process. The process contingency cost is calculated by multiplying the process contingency factor by the installed equipment cost. Guidelines developed by EPRI were used to estimate these process contingency factors (Table 7-1).

7.1.3 Total Capital Requirement

The total capital requirement for each process is estimated by adding costs for such items as general facilities, contingencies, and other costs to the total installed equipment cost. Many of these costs are determined separately for each process, but some of these costs are determined commonly to all processes.

7.1.3.1 General Facilities Cost

The general facilities cost accounts for the cost of peripheral items such as roads. It is calculated as a percentage of the total installed equipment. For most processes, however, this cost is already included in the installed equipment cost developed by using the equipment lists from Arapahoe Unit 4.

7.1.3.2 Engineering and Home Office Fees

For all processes, this was assumed to be 10% of the total installed equipment cost, based on DOE guidelines.

7.1.3.3 Project Contingency Cost

The project contingency cost reflects the level of detail and certainty in the total process capital cost. It is calculated as a percentage of the installed equipment cost. Table 7-2 lists the guidelines used to estimate project contingency factors.

Cost Estimate Type	Factor	
	Normal	Default
Simplified	30-50%	40%
Preliminary	15-30%	25%
Detailed	10-20%	15%
Finalized	5-10%	5%

Table 7-2. Project Contingency Factor Guidelines

7.1.3.4 Allowance for Funds During Construction

The allowance for funds during construction (AFDC) accounts for the cost of the capital over the course of the construction period. The AFDC was calculated by assigning a cost of 3.8% of the total plant investment for each full year required to complete construction. Generally, however, construction was assumed to require less than a year to complete, so the AFDC was assumed to be zero.

7.1.3.5 Royalty Allowance

If a process was assumed to require a royalty, the royalty cost was calculated as 0.5% of the total plant cost. The total plant cost is the sum of the total process capital, engineering and home office, and project contingency costs.

7.1.3.6 Preproduction Cost

Although more complex definitions are used for preproduction costs, this report defines the preproduction cost as the monthly O&M cost multiplied by the time a process is anticipated to require before it begins normal operations.

7.1.3.7 Inventory Capital Cost

The inventory capital cost is 60 days of variable operating costs (less credits for byproducts).

7.1.3.8 Initial Catalyst and Chemicals

The initial catalyst and chemicals cost represents any significant costs for catalysts or chemicals required by a process not counted as an inventory capital cost. None of the demonstrated systems has this cost, but the selective catalytic reduction system analyzed for comparison with the demonstrated systems does have this cost.

7.1.3.9 *Cost of Construction Downtime*

The cost of construction downtime represents the lost power sales that result from an outage required to tie in an emission control system to a retrofit unit. To simplify the evaluation, this report assumes that replacement power costs \$0.05/kWh. This assumes that the only purpose of the outage is for the installation of the project equipment. In most cases the outage required for equipment installation is planned as part of a schedule outage to complete other plant work. Thus this assumption will bias the capital cost higher than in most common installation.

7.1.4 Total Operating and Maintenance (O&M) Costs

The total O&M cost is the sum of the fixed and variable costs. All O&M costs were estimated in 1994 dollars. Variable O&M costs include costs for all of the commodities and utilities used by a process. Fixed O&M costs include the following:

- Operating labor: Number of operator-hours per day multiplied by the number of operating days per year.
- Maintenance labor: 40% of the total maintenance cost.
- Maintenance material: 60% of the total maintenance cost.
- Administration and support labor: 30% of the sum of the maintenance and operating labor costs.

The total maintenance cost was calculated as a percentage of the total process capital cost. The percentage (maintenance factor) was estimated by using the guidelines listed in Table 7-3.

Processing Conditions	Maintenance Factor
Corrosive and abrasive.	6.0%
Solids: high pressure and/or high temperature.	5.0%
Solids: low pressure and/or low temperature.	4.0%
Liquids and gases.	2.0%
Utilities	1.0%

Table 7-3. Maintenance Factor Guidelines

7.1.5 Levelized Costs

The capital and O&M costs of each process were levelized over the expected life of the unit, which was assumed to be 15 years. The levelized costs for each emission control system were calculated in both constant- and current-dollars.

7.1.5.1 Constant-Dollar Analysis

Constant-dollar analysis is based on the value of a dollar in the year of the economic analysis (1994 for this study). Constant dollars, therefore, do not incorporate the effects of inflation in capital carrying charges or operating cost projections. Constant-dollar analysis:

- Make levelized costs appear close to the costs at the time of the study.
- Appear to underestimate capital carrying charges.
- Clarify real cost trends without the effects of inflation.

7.1.5.2 Current-Dollar Analysis

Current-dollar analysis includes the expected effects of inflation on capital carrying charges and O&M costs. Current-dollar analysis:

- Estimates the values that will eventually appear in the budget estimates and other financial documents of a company.
- Appears to overemphasize O&M costs.
- Obscures real cost trends because of the effects of including inflation.

The use of either current- and constant-dollar analysis will produce the most economical option. This report uses both types of analysis. As current-dollar analysis tends to reflect actual costs and utilities tend to use it more, this report uses only current dollars to graph and compare system costs.

7.1.5.3 Levelized Costs

The experience gained from the demonstration project at Arapahoe Unit 4 was used in estimating the capital and O&M costs of the emission control systems. These costs were levelized on both a cost per power produced (mills/kW) basis and a cost per ton of pollutant removed ($/ton) basis, based on a year of operation. Various economic parameters, such as the rate of inflation, were used to calculate the levelization factors. Table 7-4 summarizes the economic parameters used to develop the levelization factors.

7.1.6 Common Technical Parameters

The economic analysis in this report assumes that each of the emission control systems is retrofitted to a 100 MWe unit. It also assumes that the unit burns Cyprus Yampa coal, the same low-sulfur coal burned by Arapahoe Unit 4 and described in Section 1.3.2. This coal has a 0.4% sulfur content and a heating value of 11,050 Btu/lb. The report also assumes that the unit operates as a base-loaded unit with a 65% capacity factor.

Economic Parameter	Units	Value
Cost of debt	%	8.5
Dividend rate for preferred stock (pre-tax)	%	7.0
Dividend rate for common stock (pre-tax)	%	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 taxes and 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 during construction (AFDC)	%	0.0
Remaining life of power plant	years	15
Year for cost presented in this report	--	1994
Royalty allowance (based on total process capital)	%	0.5
Capital charge factor	Current dollars	0.160
	Constant dollars	0.124
O&M cost 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	%	10.0
Engineering and home office fees	%	10.0

Table 7-4. Economic Parameters

7.2 Low-NO_x Combustion System

This section presents the capital and O&M costs estimated for a low-NO_x combustion system retrofitted to 100-MWe, down-fired unit. Before the retrofit, the unit's NO_x emissions are assumed to be 1.15 lb/MMBtu. The low-NO_x combustion system is assumed to reduce the unit's NO_x emissions by 65%. The retrofit is assumed to be as difficult as that experienced at Arapahoe Unit 4. The following tables summarize the estimated costs:

- Table 7-5 lists the projected O&M costs.
- Table 7-6 lists the installed equipment cost.
- Table 7-7 lists the total capital requirement.
- Table 7-8 Summarizes the power produced, NO_x removed, and levelized costs.

O&M Costs		**Quantity**	**Unit Cost**	**$\$10^6/\text{yr}$**
Fixed	Operating Labor	0.0 operator-h/day	$23.00/h	0.0
	Maintenance Labor			0.0293
	Maintenance Material			0.0439
	Administration & Support Labor			0.0088
	Total Fixed O&M Costs			0.082
Variable	Auxiliary power	1.2 kWh/h	$0.05/kWh	0.0003
	Total Variable O&M Costs			0.0003
Total O&M Cost (Fixed + Variable)				0.082

Table 7-5. Projected Operating and Maintenance Costs for Low-NO_x Combustion System (100 MWe, 65% Capacity Factor)

Item	Total Unit Cost ($/unit)	Quantity	Total Cost
Burner	$42,900	12	$514,800
Gas lighter (ignitor)	$3,100	12	$37,200
IR scanner	$3,400[1]	12	$40,800
UV scanner	$3,400[1]	12	$40,800
Sliding disk actuator	$2,000	12	$24,000
OFA damper actuator	$6,200	2	$12,400
OFA ports	$12,100	6	$72,600
Other Equipment[2]	--	--	$1,217,400
		Total design/engineering	$1,053,000
		Total procurement	$1,960,000
		Total installation	$2,903,000
		Installed equipment cost (1991 dollars)	**$5.92 ($10^6$)**

1. Includes blower, cables, and cabinets.

2. Includes modified ductwork, boiler roof tubes, OFA wall panels, rerouting of coal and gas piping, and platforms

Table 7-6. Installed Equipment Cost for Low-NO_x Combustion System (1.15 lb NO_x/MMBtu, 100 MWe, 65% NO_x Reduction)

Capital Costs		$\$10^6$	\$/kW
A_1	Installed Equipment Cost (1991 dollars)	5.92	\$59.20
A_2	Installed Equipment Cost (1994 dollars)	\$6.65	\$66.50
A_3	Retrofit Cost (Retrofit factor = 0.0)	\$0.0	\$0.00
A_4	Process Contingency (Factor = 0.10)	\$0.665	\$6.65
A	Total Process Capital Cost ($A_1+A_2+A_3+A_4$)	\$7.32	\$73.20
B	General facilities (0% of A)	\$0.0	\$0.00
C	Engineering and home office fees (10% of A)	\$0.732	\$7.32
D	Project contingency (5% of A+B+C)	\$0.403	\$4.03
E	Total plant cost (A+B+C+D)	\$8.45	\$84.50
F	Allowance for funds during construction (0% of E)	\$0.0	\$0.00
G	Total plant investment (E+F)	\$8.45	\$84.50
H	Royalty allowance (0.5% of A)	\$0.04	\$0.40
I	Preproduction costs (2 weeks of startup)	\$0.003	\$0.03
J	Inventory capital (60 days)	\$0.074	\$0.74
K	Initial catalyst and chemicals	\$0.0	\$0.00
L	Subtotal capital (G+H+I+J+K)	\$8.50	\$85.00
M	Cost of construction downtime (56 days)	\$4.37	\$43.70
N	Total capital requirement (L+M)	\$12.87	\$128.70

Table 7-7. Total Capacity Requirement for Low-NO_x Combustion System (100 MWe, 65% Capacity Factor)

PERFORMANCE		
Power Plant Attributes	Plant capacity, net	100 MWe
	Capacity factor	65%
	Power produced, net	0.569 (10^9) kWh/yr
	Plant life	15 years
	Coal sulfur content	0.4%
	Initial NO_x concentration	1.15 lb/MMBtu
Emissions Control Data	NO_x removal rate	65%
	Emissions standard: NO_x	None
	NO_x emissions without control	1.15 lb/MMBtu
	NO_x Emissions with control	0.40 lb/MMBtu
	Annual NO_x removal	2,243 tons/yr

ECONOMICS					
Power Produced Basis	**Base ($\$10^6$)**	**Current Dollars**		**Constant Dollars**	
		Factor	**mills/kW**	**Factor**	**mills/kW**
Total Capital Required	$12.87	0.160	3.62	0.124	2.80
Fixed O&M	$0.082	1.314	0.189	1.000	0.144
Variable O&M	$0.00	1.314	0.00	1.000	0.00
Total Levelized Cost	--	--	3.81	--	2.95
NO_x Removed Basis	**Base ($\$10^6$)**	**Factor**	**$/ton**	**Factor**	**$/ton**
Total Capital Required	12.87	1.314	$918	1.000	$711
Fixed O&M	0.082	1.314	$48	1.000	$37
Variable O&M	0.00	0.000	$00	0.000	$00
Total Levelized Cost	--	--	$966	--	$748

Table 7-8. Summary of Performance and Economics for Low-NO_x Combustion System

7.3 SNCR

This section presents the estimated capital and O&M costs for retrofitting an SNCR system to a 100 MWe unit operating at a 65% capacity factor. The NO_x concentration before the SNCR system is 0.4 lb/MMBtu. The SNCR system is assumed to reduce NO_x emissions by 40%. The retrofit is assumed to be as difficult as that experienced at Arapahoe Unit 4. The following tables summarize the estimated costs:

- Table 7-9 lists the projected O&M costs.
- Table 7-10 presents the installed equipment cost.
- Table 7-11 shows the total capital requirement.
- Table 7-12 summarizes the performance and levelized costs.

O&M Costs		**Quantity**	**Unit Cost**	**\$$10^6$/yr**
Fixed	Operating labor	2 operator-h/day	\$23.00/operator-h	0.0336
	Maintenance labor (maintenance factor = 2%)			0.0240
	Maintenance material			0.0361
	Administration & support labor			0.0173
			Total Fixed O&M Costs	0.111
Variable	Dry urea	0.759 tons/h	\$180/dry ton	0.350
	Reagent freight	0.759 tons/h	\$7.20/ton	0.0198
	Water use	0.447 (10^3)gal/h	\$0.60/10^3 gal	0.0023
	Auxiliary power	283 kWh/h	\$0.05/kWh	0.0806
			Total Variable O&M Costs	**0.448**
			Total O&M Cost (Fixed + Variable)	***0.559***

Table 7-9. Projected Operating and Maintenance Costs for SNCR (0.4 lb/NO_x/MMBtu, 10 MWe, 65% Capacity Factor, 40% NO_x Removal

Item	Total Unit Cost ($/unit)	Quantity	Total Cost
Urea storage tank	N/A	2	--
Urea circulation pump	N/A	2	--
Urea heater	N/A	2	--
Urea filter	N/A	2	--
Urea injection pump	N/A	2	--
Atomization compressor	N/A	1	--
Quench vessel	N/A	1	--
Quench pump	N/A	2	--
Purge fan	N/A	1	--
Water softener skid	N/A	1	--
Injection lances (level-1)	N/A	10	--
Injection lances (level-2)	N/A	10	--
Other equipment	--	--	$1,181,172
		Total design/engineering	$536,000
		Total procurement	$1,181,172
		Total installation	$711,000
Installed equipment cost for SNCR system (1991 dollars)			$2.43 ($10^6$)

Note: System at Arapahoe Unit 4 was built on a fixed-price basis and included the equipment listed above. Installed cost of equipment was estimated using these costs.

Table 7-10. SNCR Estimated Installed Equipment Cost (0.4 lb/NO_x/MMBtu, 100 MWe, 65% Capacity Factor, 40% NO_x Removal)

	Capital Costs	$\$10^6$	$/kW
A_1	Installed equipment cost (1991 dollars)	$2.43	$24.30
A_2	Installed equipment cost (1994 dollars)	$2.73	$27.30
A_3	Retrofit cost (retrofit factor = 0.0)	$0.0	$0.00
A_4	Process contingency (factor = 0.10)	$0.273	$2.73
A	Total process capital (A_1+A_2+A_3+A_4)	$3.00	$30.00
B	General facilities (0% of A)	$0.0	$0.00
C	Engineering and home office fees (10% of A)	$0.300	$3.00
D	Project contingency (5% of A+B+C)	$0.165	$1.65
E	Total plant cost (A+B+C+D)	$3.47	$34.70
F	Allowance for funds during construction (0% of E)	$0.0	$0.00
G	Total plant investment (E+F)	$3.47	$34.70
H	Royalty allowance (0.5% of A)	$0.02	$0.20
I	Preproduction costs (2 weeks of startup)	$0.022	$0.22
J	Inventory capital (60 days)	$0.074	$0.74
K	Initial catalyst and chemicals	$0.0	$0.00
L	Subtotal capital (G+H+I+J+K)	$3.58	$35.80
M	Cost of construction downtime (7 days)	$0.55	$5.50
N	Total capital requirement (L+M)	$4.13	$41.30

Table 7-11. Total Capital Requirement for SNCR (0.4 lb NO_x/MMBtu, 100 MWe, 65% Capacity Factor, 40% NO_x Removal)

PERFORMANCE		
Power Plant Attributes	Plant capacity, net	100 MWe
	Capacity factor	65%
	Power produced, net	0.569 (10^9) kWh/yr
	Plant life	15 years
	Coal sulfur content	0.4%
	Initial NO_x concentration	0.40 lb/MMBtu
Emissions Control Data	NO_x removal rate	40%
	Emissions standard: NO_x	None
	NO_x emissions without control	0.40 lb/MMBtu
	NO_x Emissions with control	0.24 lb/MMBtu
	Annual NO_x removal	480 tons/yr

ECONOMICS					
Power Produced Basis	**Base (10^6)**	**Current Dollars**		**Constant Dollars**	
		Factor	**mills/kW**	**Factor**	**mills/kW**
Total Capital Required	$4.13	0.160	1.16	0.124	0.899
Fixed O&M	$0.111	1.314	0.256	1.000	0.195
Variable O&M	$0.448	1.314	1.03	1.000	0.79
Total Levelized Cost	--	--	2.45	--	1.88
NO_x Removed Basis	**Base (10^6)**	**Factor**	**$/ton**	**Factor**	**$/ton**
Total Capital Required	4.13	1.314	$1,376	1.000	$1,066
Fixed O&M	0.111	1.314	$304	1.000	$231
Variable O&M	0.448	1.314	$1,227	1.000	$934
Total Levelized Cost	--	--	$2,906	--	$2,231

Table 7-12. Summary of Performance and Economics for SNCR

7.4 Sodium-Based DSI

This section describes the estimated capital, O&M, and levelized costs of a sodium-based DSI system retrofitted to a 100 MWe unit that burns 0.40% sulfur coal, and has a 65% capacity factor. The DSI system is assumed to reduce SO_2 emissions by 70%. The costs are estimated for sodium sesquicarbonate and sodium bicarbonate. The retrofit is assumed to be similar to that performed on Arapahoe Unit 4, but without the provisions for economizer injection.

The following tables summarize the estimated costs for this retrofit SNCR system:

- Table 7-13 lists the installed equipment cost (designed to inject either sodium sesquicarbonate or sodium bicarbonate).
- Table 7-14 lists the total capital requirement (designed to inject either sodium sesquicarbonate or sodium bicarbonate).
- Table 7-15 lists the projected O&M costs for sodium bicarbonate and lists the projected O&M costs for sodium sesquicarbonate.
- Table 7-16 summarizes the performance and levelized costs for sodium bicarbonate and Table 7-17 summarizes the performance and levelized costs for sodium sesquicarbonate.

Item	Total Unit Cost ($/unit)	Quantity	Total Cost
Reagent storage silo	$104,480	2	$208,960
Silo vent filter	$3,850	2	$7,700
Reagent screw feeder	$5,525	2	$11,050
Pneumatic conveying blower and conveying heat exchanger	$13,104	2	$26,208
Reagent pulverizer	$65,533	2	$131,066
Splitter box (duct)	$7,616	2	15,232
Rotary airlock	$9,340	2	$18,680
Other equipment	--	--	$335,950
		Total design/engineering	$199,000
		Total procurement	$754,846
		Total installation	$541,000
		Installed equipment cost (1991 dollars)	**$1.49 ($10^6$)**

Table 7-13. Estimated Installed Equipment Costs for Sodium-Based DSI (100 MWe, 0.40% Sulfur Coal, 65% Capacity Factor, 70% SO_2 Removal)

Capital Costs		**Sodium Bicarbonate**		**Sodium Sesquicarbonate**	
		10^6	**\$/kW**	**10^6**	**\$/kW**
A_1	Installed equipment cost (1991 dollars)	\$1.49	\$14.90	\$1.49	\$14.90
A_2	Installed equipment cost (1994 dollars)	\$1.68	\$16.80	\$1.68	\$16.80
A_3	Retrofit cost (retrofit factor = 0.0)	\$0.0	\$0.00	\$0.0	\$0.00
A_4	Process contingency (factor = 0.10)	\$0.168	\$1.68	\$1.68	\$16.80
A	Total process capital ($A_1+A_2+A_3+A_4$)	\$1.85	\$18.50	\$1.85	\$18.50
B	General facilities (0% of A)	\$0.0	\$0.00	\$0.0	\$0.00
C	Engineering and home office fees (10% of A)	\$0.185	\$1.85	\$0.185	\$1.85
D	Project contingency (5% of A+B+C)	\$0.102	\$1.02	\$0.102	\$1.02
E	Total plant cost (A+B+C+D)	\$2.14	\$21.40	\$2.14	\$21.40
F	Allowance for funds during construction (0% of E)	\$0.0	\$0.00	\$0.0	\$0.00
G	Total plant investment (E+F)	\$2.14	\$21.40	\$2.14	\$21.40
H	Royalty allowance (0.5% of A)	\$0.01	\$0.10	\$0.01	\$0.10
I	Preproduction costs (2 weeks of startup)	\$0.045	\$0.45	\$0.043	\$0.45
J	Inventory capital (60 days)	\$0.172	\$1.72	\$0.164	\$1.72
K	Initial catalyst and chemicals	\$0.0	\$0.00	\$0.0	\$0.00
L	Subtotal capital (G+H+I+J+K)	\$2.36	\$23.60	\$2.35	\$23.60
M	Cost of construction downtime (2 days)	\$0.16	\$1.60	\$0.16	\$1.60
N	Total capital requirement (L+M)	\$2.52	\$25.20	\$2.51	\$25.20

Table 7-14. Total Capital Requirement for Sodium-Based DSI (100 MWe, 0.40% Sulfur Coal, 65% Capacity Factor, 70% SO_2 Removal)

Sodium Bicarbonate				
O&M Costs		**Quantity**	**Unit Cost**	**$\$10^6$/yr**
Fixed	Operating Labor	4 operator-h/day	$23.00/operator-h	$0.0336
	Maintenance labor			$0.0296
	Maintenance material			$0.0444
	Administration & support labor			$0.0190
			Total Fixed O&M Costs	**$0.127**
Variable	Sodium bicarbonate	0.970 tons/h	$140/ton	$0.77
	Reagent freight	0.970 tons/h	$33/ton	$0.18
	Auxiliary power	72.5 kWh/h	$0.05/kWh	$0.0206
	Waste disposal	1.29 tons/h	$9.29/ton	$0.068
			Total Variable O&M Costs	**$1.04**
			Total O&M Cost (Fixed + Variable)	**$1.17**

Sodium Sesquicarbonate				
O&M Costs		**Quantity**	**Unit Cost**	**$\$10^6$/yr**
Fixed	Operating Labor	4 operator-h/day	$23.00/operator-h	$0.0336
	Maintenance Labor			$0.0296
	Maintenance Material			$0.0444
	Administration & Support Labor			$0.0190
	Total Fixed O&M Costs			**$0.127**
Variable	Sodium sesquicarbonate	1.53 tons/h	$65.00/ton	$0.57
	Reagent freight	1.53 tons/h	$33.00/ton	$0.29
	Auxiliary power	72.5 kWh/h	$0.05/kWh	$0.0206
	Waste disposal	2.32 tons/h	$9.29/ton	$0.123
			Total Variable O&M Costs	**$0.997**
			Total O&M Cost (Fixed + Variable)	**$1.12**

Table 7-15. Operating and Maintenance Costs of Sodium-Based DSI (0.4% Sulfur Coal, 100 MWe, 65% Capacity Factor, 70% SO_2 Removal)

PERFORMANCE		
Power Plant Attributes	Plant capacity, net	100 MWe
	Capacity factor	65%
	Power produced, net	0.569 (10^9) kWh/yr
	Plant life	15 years
	Coal feed	0.272 (10^6) tons/yr
	Sulfur content of coal	0.40%
Emissions Control Data	SO_2 removal rate	70%
	Emissions standard	1.2 lb/MMBtu
	SO_2 Emissions without control	668 lb/h 0.66 lb/MMBtu
	SO_2 Emissions with control	201 lb/h 0.198 lb/MMBtu
	SO_2 removed	467 lb/h 1,331 tons/yr

ECONOMICS					
Power Produced Basis	**Base ($\$10^6$)**	**Current Dollars**		**Constant Dollars**	
		Factor	**mills/kW**	**Factor**	**mills/kW**
Total capital requirement	\$2.52	0.160	0.708	0.124	0.549
Fixed O&M	\$0.127	1.314	0.292	1.000	0.222
Variable O&M	\$1.04	1.314	2.41	1.000	1.84
Total levelized cost	--	--	3.41	--	2.61
SO_2 Removed Basis	**Base ($\$10^6$)**	**Factor**	**\$/ton**	**Factor**	**\$/ton**
Total capital requirement	\$2.52	0.160	\$303	0.124	\$235
Fixed O&M	\$0.127	1.314	\$125	1.000	\$95
Variable O&M	\$1.04	1.314	\$1,032	1.000	\$785
Total levelized cost	--	--	\$1,460	--	\$1,115

Table 7-16. Summary of Performance and Economics of DSI (Sodium Bicarbonate)

PERFORMANCE		
Power Plant Attributes	Plant capacity, net	100 MWe
	Capacity factor	65%
	Power produced, net	0.569 (10^9) kWh/yr
	Plant life	15 years
	Coal feed	0.272 (10^6) tons/yr
	Sulfur content of coal	0.40%
Emissions Control Data	SO_2 removal rate	70%
	Emissions standard	1.2 lb/MMBtu
	SO_2 Emissions without control	668 lb/h 0.66 lb/MMBtu
	SO_2 Emissions with control	201 lb/h 0.198 lb/MMBtu
	SO_2 removed	467 lb/h 1,331 tons/yr

ECONOMICS					
Power Produced Basis	**Base ($\$10^6$)**	**Current Dollars**		**Constant Dollars**	
		Factor	**mills/kW**	**Factor**	**mills/kW**
Total capital requirement	\$2.51	0.160	0.705	0.124	0.547
Fixed O&M	\$0.127	1.314	0.292	1.000	0.222
Variable O&M	\$0.997	1.314	2.30	1.000	1.75
Total levelized cost	--	--	3.30	--	2.52
SO_2 Removed Basis	**Base ($\$10^6$)**	**Factor**	**\$/ton**	**Factor**	**\$/ton**
Total capital requirement	\$2.51	0.160	\$302	0.124	\$234
Fixed O&M	\$0.127	1.314	\$125	1.000	\$95
Variable O&M	\$0.997	1.314	\$985	1.000	\$750
Total levelized cost	--	--	\$1,412	--	\$1,079

Table 7-17. Summary of Performance and Economics of DSI (Sodium Sesquicarbonate)

7.5 Calcium-based DSI

This section presents the capital, O&M, and levelized costs for retrofitting calcium-based DSI to a 100 MWe unit burning 0.4% sulfur coal and operating with a 65% capacity factor. The retrofit difficulty of both systems is assumed to be about the same as it was for Arapahoe Unit 4. The costs are presented for the retrofit of two different calcium-based DSI systems: (1) economizer injection of hydrated lime and (2) duct injection of hydrated lime with flue-gas humidification.

7.5.1 Economizer Injection of Hydrated Lime

This section presents the capital, O&M, and levelized costs for retrofitting economizer injection of hydrated lime to the unit described above. This DSI system is assumed to reduce SO_2 emissions by only 15%. The following tables summarize the costs:

- Table 7-18 presents the installed equipment cost and Table 7-19 lists the total capital requirement cost.
- Table 7-20 shows the projected O&M costs and Table 7-21 summarizes the performance and levelized costs.

Item	Total Unit Cost ($/unit)	Quantity	Total Cost
Reagent storage silo	$104,480	2	$208,960
Silo vent filter	$4,043	2	$8,086
Reagent screw feeder	$5,525	2	$11,050
Pneumatic conveying blower and conveying heat exchanger	$13,104	2	$26,208
Splitter box	$7,616	2	15,232
Rotary airlock	$9,340	2	$18,680
Other equipment	--	--	$335,950
		Total design/engineering	$159,200
		Total procurement	$610,676
		Total installation	$432,800
		Total installed equipment cost (1991 dollars)	**$1.20 ($10^6$)**

Table 7-18. Installed Equipment Cost for Economizer Injection of Hydrated Lime (0.4% Sulfur Coal, 100 MWe, 65% Capacity Factor, 70% SO_2 Removal)

Capital Costs		$\$10^6$	\$/kW
A_1	Installed Equipment (1991 dollars)	\$1.20	\$12.00
A_2	Installed Equipment (1994 dollars)	\$1.35	\$13.50
A_3	Retrofit Cost (Retrofit factor = 0.0)	\$0.0	\$0.00
A_4	Process Contingency (Factor = 0.10)	\$0.135	\$1.35
A	Total Process Capital (A_1+A_2+A_3+A_4)	\$1.49	\$14.90
B	General facilities (0% of A)	\$0.0	\$0.00
C	Engineering and home office fees (10% of A)	\$0.149	\$1.49
D	Project contingency (5% of A+B+C)	\$0.082	\$0.82
E	Total plant cost (A+B+C+D)	\$1.72	\$17.20
F	Allowance for funds during construction (0% of E)	\$0.0	\$0.00
G	Total plant investment (E+F)	\$1.72	\$17.20
H	Royalty allowance (0.5% of A)	\$0.009	\$0.09
I	Preproduction costs (2 weeks of startup)	\$0.024	\$0.24
J	Inventory capital (60 days)	\$0.087	\$0.87
K	Initial catalyst and chemicals	\$0.0	\$0.00
L	Subtotal capital (G+H+I+J+K)	\$1.84	\$18.40
M	Cost of construction downtime (7 days)	\$0.55	\$5.50
N	Total capital requirement (L+M)	\$2.39	\$23.90

Table 7-19. Total Capital Requirement for Economizer Injection of Hydrated Lime (0.40% Sulfur Coal, 100 MWe, 65% Capacity Factor, 15% SO_2 Removal)

O&M Costs		**Units**	**Quantity**	**$/Unit**	**$\$10^6$/yr**
Fixed	Operating Labor	operator-h/day	3	$23.00	$0.025
	Maintenance labor (maintenance factor = 0.04)				$0.024
	Maintenance material				$0.036
	Administration & support labor				$0.015
				Total Fixed O&M Costs	**$0.0994**
Variable	Hydrated lime	tons/h	0.859	$62/ton	$0.303
	Reagent freight	tons/h	1.13	$33/ton	$0.162
	Auxiliary power	kW-h/h	25	$0.05/kW-h	$0.007
	Waste disposal	tons/h	1.29	$9.29/ton	$0.0599
				Total Variable O&M Costs	**$0.531**
				Total O&M Cost (Fixed + Variable)	**$0.630**

Table 7-20. Operating and Maintenance Costs of Economizer Injection of Hydrated Lime (0.4% Sulfur Coal, 100 MWe, 65% Capacity Factor, 15% SO_2 Removal)

	PERFORMANCE	
Power Plant Attributes	Plant capacity, net	100 MWe
	Capacity factor	65%
	Power produced, net	0.569 (10^9) kWh/yr
	Plant life	15 years
	Coal feed	0.272 (10^6) tons/yr
	Sulfur content of coal	0.40%
Emissions Control Data	SO_2 removal rate	15%
	Emissions standard	1.2 lb/MMBtu
	SO_2 Emissions without control	668 lb/h 0.66 lb/MMBtu
	SO_2 Emissions with control	568 lb/h 0.56 lb/MMBtu
	SO_2 removed	100 lb/h 285 tons/yr

ECONOMICS					
	Base ($\$10^6$)	**Current Dollars**		**Constant Dollars**	
		Factor	**mills/kW**	**Factor**	**mills/kW**
Total capital requirement	$2.39	0.160	0.670	0.124	0.519
Fixed O&M	$0.099	1.314	0.229	1.000	0.175
Variable O&M	$0.532	1.314	1.23	1.000	0.93
Total levelized cost	--	--	2.13	--	1.63
SO_2 Removed Basis	**Base ($\$10^6$)**	**Factor**	**$/ton**	**Factor**	**$/ton**
Total capital requirement	$2.39	0.160	$1,338	0.124	$1,037
Fixed O&M	$0.099	1.314	$458	1.000	$349
Variable O&M	$0.532	1.314	$2,451	1.000	$1,865
Total levelized cost	--	--	$4,247	--	$3,251

Table 7-21. Summary of Performance and Economics of Economizer Injection of Hydrated Lime

7.5.2 Flue-Gas Humidification

This section presents the capital, O&M, and levelized costs for retrofitting duct injection of hydrated lime with flue-gas humidification to the unit described above. This DSI system is assumed to reduce SO_2 emissions by 30%. The following tables summarize the costs:

- Table 7-22 shows the projected O&M costs.
- Table 7-23 presents the installed equipment cost.
- Table 7-24 lists the total capital requirement.
- Table 7-25 summarizes the performance and levelized costs.

O&M Costs		**Use Rate**	**Unit Cost**	**Cost $\$10^6$/yr**
Fixed	Operating Labor	4 operator-h/day	\$23.00/operator-h	\$0.0336
	Maintenance Labor			\$0.055
	Maintenance Material			\$0.083
	Administration & Support Labor			\$0.027
			Total Fixed O&M Costs	**\$0.20**
Variable	Hydrated lime	0.859 tons/h	\$62/ton	\$0.303
	Reagent freight	0.859 tons/h	\$33/ton	\$0.161
	Water	0.049 10^3 gal/h	\$0.60/10^3 gal	\$0.00017
	Auxiliary power	1,134 kW-h/h	\$0.05/kW-h	\$0.323
	Waste disposal	1.20 tons/h	\$9.29/ton	\$0.0637
			Total Variable O&M Costs	**\$0.548**
			Total O&M Cost (Fixed + Variable)	**\$0.75**

Table 7-22. Operating and Maintenance Costs of Duct Injection of Hydrated Lime with Flue-Gas Humidification (0.4% Sulfur Coal, 100 MWe, 65% Capacity Factor, 30% SO_2 Removal)

Item	Total Unit Cost ($/unit)	Quantity	Total Cost
Humidification lances	13,600	14	$190,400
Water pump	$3,115	1	$3,115
Atomization air compressor	$80,560	2	$161,120
Shield air fan	$2,321	1	$2,321
Other equipment[2]	--	--	$424,050
Total design/engineering			$330,000
Total procurement			$781,006
Total installation			$470,000
Total Installed Equipment Cost (1991 dollars)		**Humidification**	**$1.58 ($10^6$)**
		DSI[1]	**$1.20 ($10^6$)**
		Total	**$2.78 ($10^6$)**

1. Assumes equipment costs same as those for economizer injection of hydrated lime.
2. Includes control valves, platforms, piping, and other equipment.

Table 7-23. Flue-Gas Humidification System Estimated Installed Equipment Costs (0.4% Sulfur Coal, 100 MWe, 65% Capacity Factor, 30% SO_2 Removal)

Capital Costs		$\$10^6$	\$/kW
A_1	Installed Equipment (1991 dollars)	\$2.78	\$27.80
A_2	Installed Equipment (1994 dollars)	\$3.13	\$31.30
A_3	Retrofit Cost (Retrofit factor = 0.0)	\$0.0	\$0.00
A_4	Process Contingency (Factor = 0.10)	\$0.313	\$3.13
A	Total Process Capital (A_1+A_2+A_3+A_4)	\$3.44	\$34.40
B	General facilities (0% of A)	\$0.0	\$0.00
C	Engineering and home office fees (10% of A)	\$0.344	\$3.44
D	Project contingency (5% of A+B+C)	\$0.189	\$1.89
E	Total plant cost (A+B+C+D)	\$3.98	\$39.80
F	Allowance for funds during construction (0% of E)	\$0.0	\$0.00
G	Total plant investment (E+F)	\$3.98	\$39.80
H	Royalty allowance (0.5% of A)	\$0.020	\$0.20
I	Preproduction costs (2 weeks of startup)	\$0.029	\$0.29
J	Inventory capital (60 days)	\$0.090	\$0.90
K	Initial catalyst and chemicals	\$0.0	\$0.00
L	Subtotal capital (G+H+I+J+K)	\$4.12	\$41.20
M	Cost of construction downtime (2 days)	\$0.16	\$1.60
N	Total capital requirement (L+M)	\$4.27	\$42.70

Table 7-24. Total Capital Requirement for Duct Injection of Hydrated Lime and Flue-Gas Humidification (0.40% Sulfur Coal, 100 MWe, 65% Capacity Factor, 15% SO_2 Removal)

	PERFORMANCE	
Power Plant Attributes	Plant capacity, net	100 MWe
	Capacity factor	65%
	Power produced, net	0.569 (10^9) kWh/yr
	Plant life	15 years
	Coal feed	0.272 (10^6) tons/yr
	Sulfur content of coal	0.40%
Emissions Control Data	SO_2 removal rate	30%
	Emissions standard	1.2 lb/MMBtu
	SO_2 Emissions without control	668 lb/h 0.66 lb/MMBtu
	SO_2 Emissions with control	468 lb/h 0.46 lb/MMBtu
	SO_2 removed	200 lb/h 570 tons/yr

ECONOMICS					
Power Produced Basis	**Base ($$10^6$)**	**Current Dollars**		**Constant Dollars**	
		Factor	**mills/kW**	**Factor**	**mills/kW**
Total capital requirement	$4.27	0.160	1.20	0.124	0.931
Fixed O&M	$0.198	1.314	0.457	1.000	0.348
Variable O&M	$0.548	1.314	1.26	1.000	0.96
Total levelized cost	--	--	2.92	--	2.24
SO2 Removed Basis	Base ($106)	Factor	$/ton	Factor	$/ton
Total capital requirement	$4.27	0.160	$1,199	0.124	$929
Fixed O&M	$0.198	1.314	$456	1.000	$347
Variable O&M	$0.548	1.314	$1,263	1.000	$961
Total levelized cost	--	--	$2,917	--	$2,237

Table 7-25. Summary of Performance and Economics of Duct Injection of Hydrated Lime with Flue-Gas Humidification

7.6 Integrated Systems

This section presents the capital, O&M, and levelized costs of the following integrated systems:

- Integrated Dry NO_x/SO_2 Emissions Control System (low-NO_x combustion system, SNCR, and DSI with sodium bicarbonate).
- SNCR and DSI (the Integrated Dry NO_x/SO_2 Emissions Control System without low-NO_x combustion system).
- LSFO and SCR (for comparison).

The costs of the systems were integrated by adding the estimated cost for each system. For example, the fixed O&M cost of the Integrated Dry NO_x/SO_2 Emissions Control System ($0.267 million) was calculated by adding the fixed O&M costs for the low-NO_x combustion system ($0.0293 million), SNCR ($0.111 million) and DSI ($0.127 million).

The following tables present the estimated costs of the integrated systems:

- Table 7-26 shows the total capital requirements of the integrated systems.
- Table 7-27 lists the O&M costs of the integrated systems.
- Table 7-28 summarizes the performance and levelized costs of the Integrated Dry NO_x/SO_2 Emissions Control System.
- Table 7-29 summarizes the performance and levelized costs of the integration of SNCR and DSI.
- Table 7-30 summarizes the performance and levelized costs of the integration of SCR and LSFO.

System		$\$10^6$	\$/kW
Integrated	Low-NO_x Combustion System	\$12.87	\$128.7
	SNCR	\$4.13	\$41.3
	DSI (Sodium bicarbonate)	\$2.52	\$25.2
	Total capital requirement	\$19.52	\$195.2
SNCR and DSI	SNCR	\$4.13	\$41.3
	DSI (Sodium bicarbonate)	\$2.52	\$25.2
	Total capital requirement	\$6.65	\$66.5
SCR and LSFO	SCR	\$11.05	\$110.5
	LSFO	\$28.31	\$283.1
	Total capital requirement	\$39.37	\$393.7

Table 7-26. Total Capital Requirements of Integrated Systems

System		Operating and Maintenance ($\$10^6$)	
		Fixed	**Variable**
Integrated	Low-NO_x Combustion System	\$0.029	\$0.00034
	SNCR	\$0.111	\$0.443
	DSI (Sodium bicarbonate)	\$0.127	\$1.04
	Total	\$0.267	\$1.49
SNCR and DSI	SNCR	\$0.111	\$0.443
	DSI (Sodium bicarbonate)	\$0.127	\$1.04
	Total	\$0.237	\$1.49
SCR and LSFO	SCR	\$0.160	\$1.21
	LSFO	\$1.66	\$0.581
	Total	\$1.82	\$1.79

Table 7-27. Estimated Operating and Maintenance Costs of Integrated Systems

	PERFORMANCE		
Power Plant Attributes	Plant capacity, net	100 MWe	
	Capacity factor	65%	
	Power produced, net	0.569 (10^9) kWh/yr	
	Plant life	15 years	
	Coal sulfur content	0.4%	
Emissions Control Data		NO_x	SO_2
	Removal rate	79%	70%
	Emissions without control	1.15 lb/MMBtu	0.80 lb/MMBtu
	Emissions with control	0.24 lb/MMBtu	0.24 lb/MMBtu
	Annual combined NO_x and SO_2 removal	4,055 tons/yr	

ECONOMICS					
		Current Dollars		**Constant Dollars**	
Power Produced Basis	**Base ($$10^6$)**	**Factor**	**mills/kW**	**Factor**	**mills/kW**
Total Capital Required	$19.5	0.160	5.48	0.124	4.25
Fixed O&M	$0.267	1.314	0.62	1.000	0.47
Variable O&M	$1.49	1.314	3.43	1.000	2.61
Total Levelized Cost	--	--	9.53	--	7.33
NO_x Removed Basis	**Base ($$10^6$)**	**Factor**	**$/ton**	**Factor**	**$/ton**
Total Capital Required	$19.5	0.160	$770	0.124	$597
Fixed O&M	$0.267	1.314	$86	1.000	$66
Variable O&M	$1.49	1.314	$482	1.000	$367
Total Levelized Cost	--	--	$1,339	--	$1,030

Table 7-28. Summary of Performance and Economics for Integrated System

	PERFORMANCE		
Power Plant Attributes	Plant capacity, net	100 MWe	
	Capacity factor	65%	
	Power produced, net	0.569 (10^9) kWh/yr	
	Plant life	15 years	
	Coal sulfur content	0.4%	
Emissions Control Data		NO_x	SO_2
	Removal rate	40%	70%
	Emissions without control	0.40 lb/MMBtu	0.80 lb/MMBtu
	Emissions with control	0.24 lb/MMBtu	0.24 lb/MMBtu
	Annual combined NO_x and SO_2 removal	1,811 tons/yr	

ECONOMICS					
Power Produced Basis	**Base ($$10^6$)**	**Current Dollars**		**Constant Dollars**	
		Factor	**mills/kW**	**Factor**	**mills/kW**
Total Capital Required	$6.65	0.160	1.87	0.124	1.45
Fixed O&M	$0.237	1.314	0.55	1.000	0.42
Variable O&M	$1.49	1.314	3.43	1.000	2.61
Total Levelized Cost	--	--	5.85	--	4.48
NO_x Removed Basis	**Base ($$10^6$)**	**Factor**	**$/ton**	**Factor**	**$/ton**
Total Capital Required	$6.65	0.160	$587	0.124	$455
Fixed O&M	$0.237	1.314	$172	1.000	$131
Variable O&M	$1.49	1.314	$1,079	1.000	$822
Total Levelized Cost	--	--	$1,839	--	$1,408

Table 7-29. Summary of Performance and Economics for Integration of SNCR and Sodium-Based DSI

	PERFORMANCE		
Power Plant Attributes	Plant capacity, net	100 MWe	
	Capacity factor	65%	
	Power produced, net	0.569 (10^9) kWh/yr	
	Plant life	15 years	
	Coal sulfur content	0.4%	
Emissions Control Data		NO$_x$	SO$_2$
	Removal rate	80%	90%
	Emissions without control	0.40 lb/MMBtu	0.80 lb/MMBtu
	Emissions with control	0.08 lb/MMBtu	0.08 lb/MMBtu
	Annual combined NO$_x$ and SO$_2$ removal	2,672 tons/yr	

ECONOMICS					
		Current Dollars		**Constant Dollars**	
Power Produced Basis	**Base (10^6)**	**Factor**	**mills/kW**	**Factor**	**mills/kW**
Total Capital Required	$39.37	0.160	11.06	0.124	8.57
Fixed O&M	$1.82	1.314	4.20	1.000	3.20
Variable O&M	$1.79	1.314	4.14	1.000	3.15
Total Levelized Cost	--	--	19.40	--	14.92
NO$_x$ Removed Basis	**Base (10^6)**	**Factor**	**$/ton**	**Factor**	**$/ton**
Total Capital Required	$39.37	0.160	$2,358	0.124	$1,827
Fixed O&M	$1.82	1.314	$895	1.000	$213
Variable O&M	$1.79	1.314	$883	1.000	$672
Total Levelized Cost	--	--	$4,136	--	$2,712

Table 7-30. Summary of Performance and Economics for Integration of SCR and LSFO

8 EFFECT OF VARIABLES ON ECONOMICS

This section describes the effects of varying economic parameters, such as unit size, on the capital and levelized costs of the emissions control systems. The effects of these parameters on the costs of the emissions control systems are compared with the demonstrated systems and emission control systems likely to compete with them. These systems are selective catalytic reduction for NO_x control and a wet scrubber for SO_2 control. This section first presents the capital, O&M and levelized costs of LSFO and SCR. It then describes the effects varying the economic parameters on the NO_x emission control systems, the SO_2 emission control systems, and the integrated NO_x/SO_2 emissions control systems.

8.1 Competing Technologies

To better analyze the performance and economics of the demonstrated emission control systems, the economics of emission control systems likely to compete with the demonstration project were also analyzed. The SO_2 control system to most likely compete with DSI with or without humidification is the wet scrubber. The most likely system to compete with low-NO_x combustion systems or SNCR is selective catalytic reduction (SCR). There are many types of wet scrubbers, but this study only evaluated one of the most common types, limestone with forced oxidation (LSFO). This section presents the estimated capital, O&M, and levelized costs of LSFO and SCR. These estimated costs are meant only for initial comparisons with the demonstrated systems.

The installed equipment costs for LSFO and SCR were estimated on a cost-per-kilowatt-produced basis using EPRI literature, vendor literature, and engineering judgment. Both systems were assumed to be retrofit to a 100 MWe unit burning 0.40% sulfur coal and operating with a 65% capacity factor. Appendix I details the assumptions used to evaluate the LSFO and SCR systems.

8.1.1 Limestone Forced Oxidation

The evaluated LSFO system is assumed to reduce SO_2 emissions by 90%. This removal is based on 91% utilization of the limestone, which contains 94% calcium carbonate ($CaCO_3$). The following tables summarize the estimated costs of LSFO:

- Table 8-1 presents the projected O&M costs.
- Table 8-2 lists the total capital requirement.
- Table 8-3 summarizes the performance and levelized costs.

O&M Costs		**Use Rate**	**Unit Cost**	**$10^6/yr**
Fixed	Operating Labor	2.3 operators/shift 4.2 shifts/week	$23.00	$0.464
	Maintenance labor (maintenance factor = 0.046)			$0.378
	Maintenance material			$0.566
	Administration & support labor			$0.253
	Total Fixed O&M Costs			$1.66
Variable	Limestone	0.550 tons/h	$15/ton	$0.047
	Reagent freight	0.550 tons/h	$33/ton	$0.063
	Auxiliary power	1,657 kW-h/h	$0.05/kW-h	$0.472
	Waste disposal	0.886 tons/h	$9.29/ton	$0.0469
			Total Variable O&M Costs	**$0.581**
			Total O&M Cost (Fixed + Variable)	**$2.24**

Table 8-1. Estimated Operating and Maintenance Costs of LSFO (0.5% Sulfur Coal, 100 MWe, 65% Capacity Factor, 90% SO_2 Removal)

	Capital Costs	$\$10^6$	\$/kW
A_1	Installed Equipment (1994 dollars)	\$18.0	\$180
A_2	Retrofit Cost (Retrofit factor = 0.12)	\$2.16	\$21.6
A_3	Process Contingency (Factor = 0.02)	\$0.360	\$3.6
A	Total Process Capital (A_1+A_2+A_3)	\$20.5	\$205
B	General facilities (0% of A)	\$2.05	\$20.5
C	Engineering and home office fees (10% of A)	\$2.05	\$20.5
D	Project contingency (12% of A+B+C)	\$2.96	\$29.6
E	Total plant cost (A+B+C+D)	\$27.6	\$276
F	Allowance for funds during construction (0% of E)	\$0.0	\$0.00
G	Total plant investment (E+F)	\$27.6	\$276
H	Royalty allowance (0.5% of A)	\$0.14	\$1.40
I	Preproduction costs (8 weeks of startup)	\$0.345	\$3.45
J	Inventory capital (60 days)	\$0.096	\$0.96
K	Initial catalyst and chemicals	\$0.0	\$0.00
L	Subtotal capital (G+H+I+J+K)	\$28.2	\$282
M	Cost of construction downtime (2 days)	\$0.16	\$1.60
N	Total capital requirement (L+M)	\$28.3	\$283

Table 8-2. Total Capital Requirement for LSFO (0.40% Sulfur Coal, 1000 MWe, 65% Capacity Factor, 90% SO_2 Removal)

PERFORMANCE		
Power Plant Attributes	Plant capacity, net	100 MWe
	Capacity factor	65%
	Power produced, net	0.569 (10^9) kWh/yr
	Plant life	15 years
	Coal feed	0.272 (10^6) tons/yr
	Sulfur content of coal	0.40%
Emissions Control Data	SO_2 removal rate	90%
	Emissions standard	1.2 lb/MMBtu
	SO_2 Emissions without control	668 lb/h 0.8 lb/MMBtu
	SO_2 Emissions with control	66.8 lb/h 0.08 lb/MMBtu
	SO_2 removed	601 lb/h 1,711 tons/yr

ECONOMICS					
Power Produced Basis	**Base (10^6)**	**Current Dollars**		**Constant Dollars**	
		Factor	**mills/kWh**	**Factor**	**mills/kWh**
Total capital requirement	$28.3	0.160	7.96	0.124	6.17
Fixed O&M	$1.66	1.314	3.83	1.000	2.92
Variable O&M	$0.581	1.314	1.34	1.000	1.02
Total levelized cost	--	--	13.1	--	10.1
SO_2 Removed Basis	Base (10^6)	Factor	$/ton	Factor	$/ton
Total capital requirement	$28.3	0.160	$2,647	0.124	$2,052
Fixed O&M	$1.66	1.314	$1,275	1.000	$970
Variable O&M	$0.581	1.314	$446	1.000	$340
Total levelized cost	--	--	$4,369	--	$3,362

Table 8-3. Summary of Estimated Performance and Economics of LSFO

8.1.2 Selective Catalytic Reduction

The evaluated SCR system is assumed to reduce NO_x emissions by 80%. This reduction is based on ratio of 1.14 moles of NH_3 for each mole of NO_x removed. In the analysis, the total installed capital cost of SCR does not include the initial catalyst as this is included separately.

A major operating expense of SCR is the replacement of the catalyst. Catalyst life depends on the type of catalyst, sulfur content, and many other factors. Catalyst life can range from as little as one year to more than seven years. For this study, the catalyst life is assumed to be three years. The amount of catalyst required for each replacement varies greatly and there are many methods of replacement. For this study, the total number of replacements the SCR plant would require over the remaining life of the plant was calculated. If all of the catalyst is replaced every three years, the cost of these replacements would also occur every three years, but O&M costs are reported on an annual basis. Therefore, to estimate an annual O&M cost, the costs of these replacements were summed and divided by the remaining life of the plant. The following tables summarize the estimated costs of LSFO:

- Table 8-4 lists the total capital requirement.
- Table 8-5 presents the projected O&M costs.
- Table 8-6 summarizes the performance and levelized costs.

	Capital Costs	$\$10^6$	\$/kW
A_1	Installed Equipment (1994 dollars)	\$4.15	\$41.5
A_2	Retrofit Cost (Retrofit factor = 0.10)	\$0.42	\$4.2
A_3	Process Contingency (Factor = 0.15)	\$0.623	\$6.23
A	Total Process Capital ($A_1+A_2+A_3$)	\$5.19	\$5.19
B	General facilities (5% of A)	\$0.259	\$2.59
C	Engineering and home office fees (10% of A)	\$0.519	\$5.19
D	Project contingency (15% of A+B+C)	\$0.895	\$8.95
E	Total plant cost (A+B+C+D)	\$7.76	\$77.6
F	Allowance for funds during construction (0% of E)	\$6.86	\$68.6
G	Total plant investment (E+F)	\$6.86	\$68.6
H	Royalty allowance (0.0% of A)	\$0.0	\$0.00
I	Preproduction costs (2 weeks of startup)	\$0.053	\$0.53
J	Inventory capital (60 days)	\$0.201	\$2.01
K	Initial catalyst and chemicals	\$2.85	\$28.5
L	Subtotal capital (G+H+I+J+K)	\$9.96	\$99.6
M	Cost of construction downtime (14 days)	\$1.09	\$10.9
N	Total capital requirement (L+M)	\$11.06	\$11.06

Table 8-4. Total Capital Requirement for SCR (0.40 lb NOx /MMBtu, 100 MWe, 65% Capacity Factor, 80% NOx Removal)

O&M Costs		Use Rate	Unit Cost	Cost $\$10^6$/yr
Fixed	Operating Labor	4 operator-h/day	\$23.00/operator-h	\$0.0336
	Maintenance Labor (maintenance factor = 0.02)			\$0.0415
	Maintenance Material			\$0.0623
	Administration & Support Labor			\$0.0225
	Total Fixed O&M Costs			\$0.160
Variable	NH_3	0.109 tons/h	\$150/dry ton	\$0.093
	Dilute NH_3 freight	0.371 tons/h	\$7.20/ton	\$0.0152
	Auxiliary power	1,250 kWh/h	\$0.05/kWh	\$0.356
	Catalyst	3 year life	\$475/ft^3	\$0.760
			Total Variable O&M Costs	**\$1.22**
			Total O&M Cost (Fixed + Variable)	**\$1.38**

Table 8-5. Estimated Operating and Maintenance Costs of SCR (0.4 lb NO_x /MMBtu, 100 MWe, 65% Capacity Factor, 80% NO_x Removal)

PERFORMANCE		
Plant Attributes	Plant capacity, net	100 MWe
	Capacity factor	65%
	Power produced, net	0.569 (10^9) kWh/yr
	Plant life	15 years
	Coal sulfur content	0.4%
	Initial NO_x concentration	0.40 lb/MMBtu
Emissions Control Data	NO_x removal rate	80%
	Emissions standard: NO_x	N/A
	NO_x emissions without control	0.40 lb/MMBtu
	NO_x Emissions with control	0.08 lb/MMBtu
	Annual NO_x removal	960 tons/yr

ECONOMICS					
Power Produced Basis	**Base ($\$10^6$)**	**Current Dollars**		**Constant Dollars**	
		Factor	**mills/kWh**	**Factor**	**mills/kWh**
Total Capital Required	$11.06	0.160	3.11	0.124	2.41
Fixed O&M	$0.160	1.314	0.369	1.000	0.281
Variable O&M	$1.224	1.314	2.83	1.000	2.15
Total Levelized Cost	--	--	6.30	--	4.84
NO_x Removed Basis	**Base ($\$10^6$)**	**Factor**	**$/ton**	**Factor**	**$/ton**
Total Capital Required	11.06	0.160	$1,842	0.124	$1,428
Fixed O&M	0.160	1.314	$219	1.000	$166
Variable O&M	1.224	1.314	$1,675	1.000	$1,275
Total Levelized Cost	--	--	$3,736	--	$2,869

Table 8-6. Summary of Estimated Performance and Economics for SCR

8.2 NO_x Emission Control Systems

This section describes the effects of varying the initial NO_x concentration, unit size, capacity factor, and NO_x removal rate for the NO_x emission control systems.

Figures 8-1 through 8-3 summarize and graph the effects of varying the initial NO_x concentration:

- Figure 8-1 shows the effect on the total capital requirement.
- Figure 8-2 shows the effect on the levelized costs (mills/kW).
- Figure 8-3 shows the effect on the levelized costs ($/ton).

Figures 8-4 through 8-6 summarize and graph the effects of varying the size of the unit:

- Figure 8-4 shows the effect on the total capital requirement.
- Figure 8-5 shows the effect on the levelized costs (mills/kW).
- Figure 8-6 shows the effect on the levelized costs ($/ton).

Figures 8-7 through 8-9 summarize and graph the effects of varying the capacity factor:

- Figure 8-7 shows the effect on the total capital requirement.
- Figure 8-8 shows the effect on the levelized costs (mills/kW).
- Figure 8-9 shows the effect on the levelized costs ($/ton).

Figures 8-10 through 8-12 summarize and graph the effects of varying the NO_x removal rate of the system:

- Figure 8-10 shows the effect on the total capital requirement.
- Figure 8-11 shows the effect on the levelized costs (mills/kW).
- Figure 8-12 shows the effect on the levelized costs ($/ton).

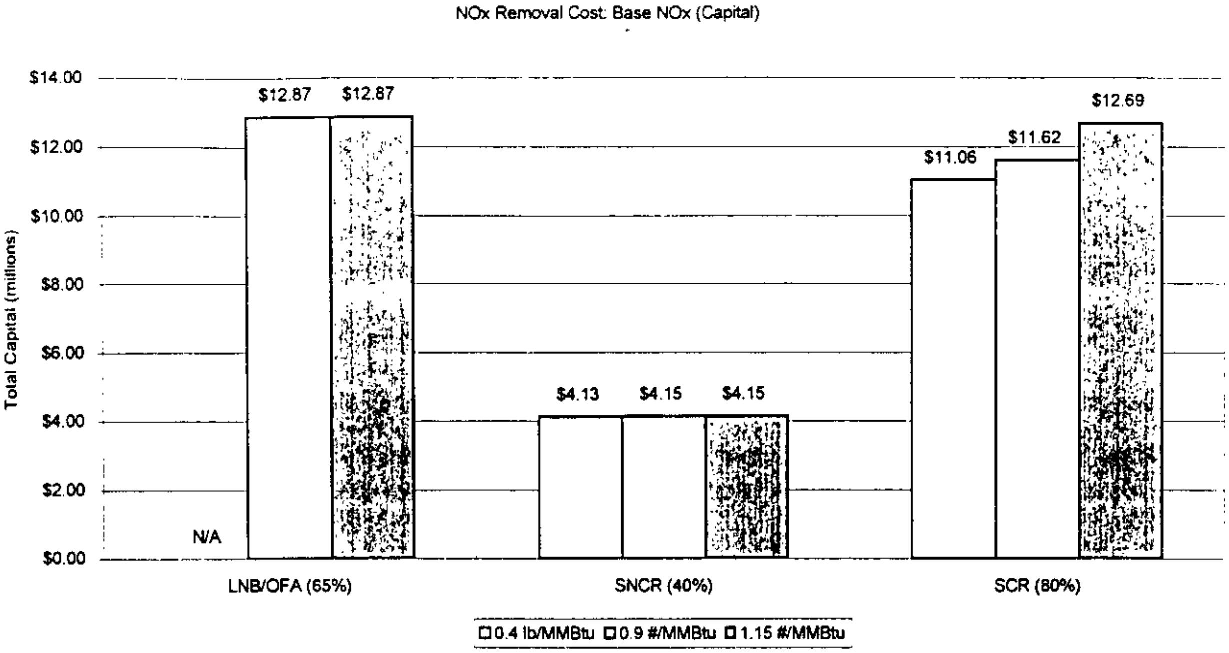

Figure 8-1. Effect of Initial NO_x Concentration on Capital Cost of NO_x Control Systems

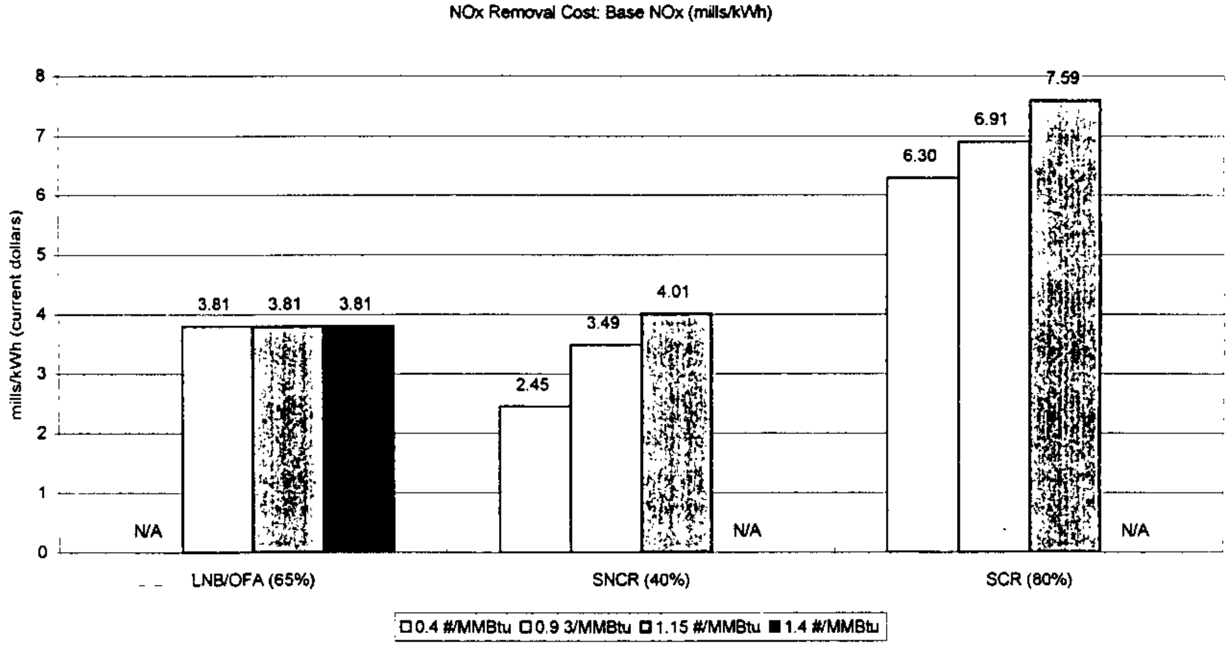

Figure 8-2. Effect of Initial NO_x Concentration on Levelized Cost (mills/kW) on NO_x Control Systems

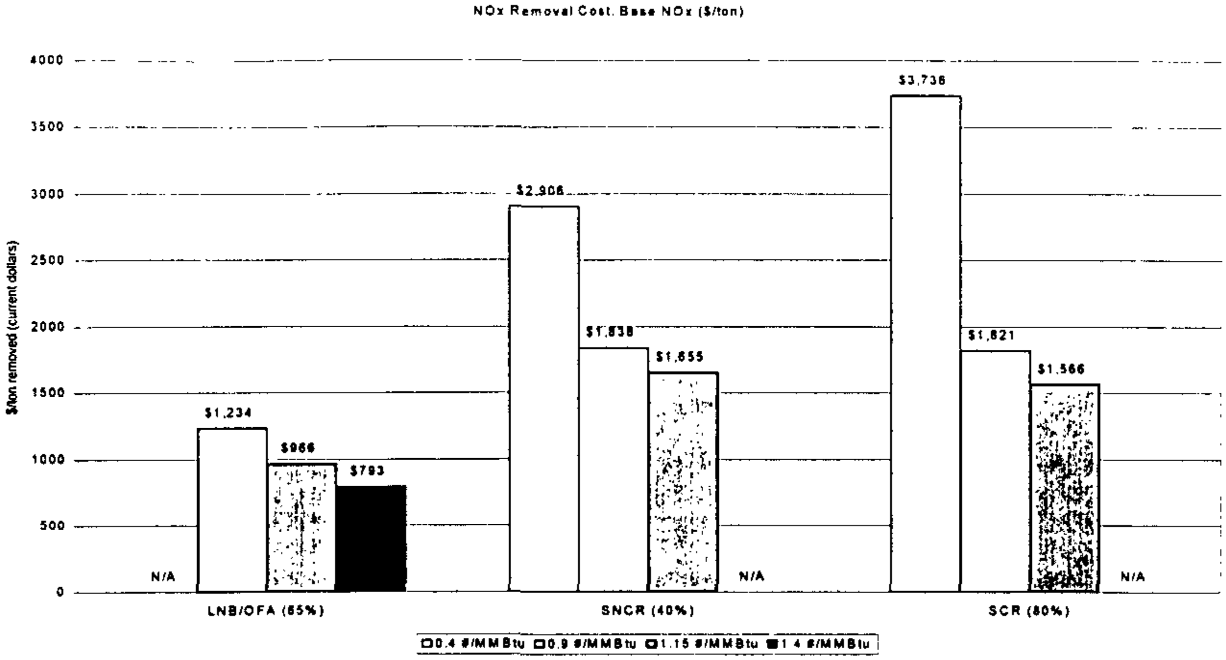

Figure 8-3. Effect of Initial NO_x Concentration on Levelized Cost ($/ton) NO_x Control

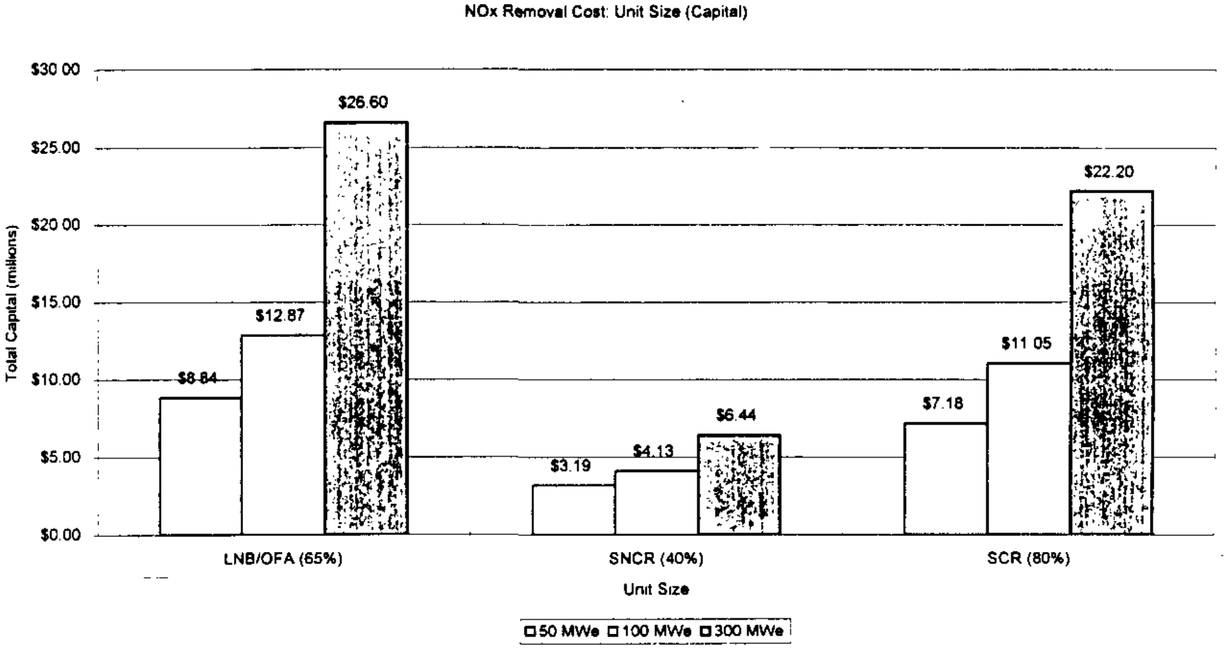

Figure 8-4. Effect of Unit Size on Capital Cost of NO_x Control Systems

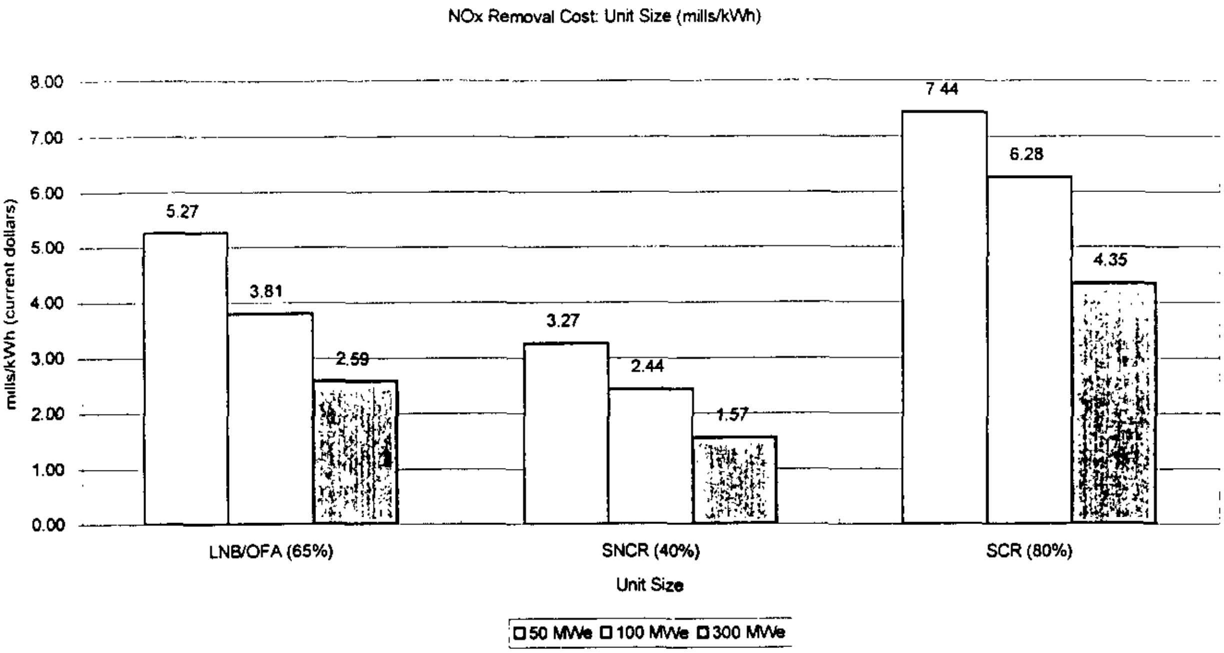

Figure 8-5. Effect of Unit Size on Levelized Cost (mills/kW) of NO_x Control Systems

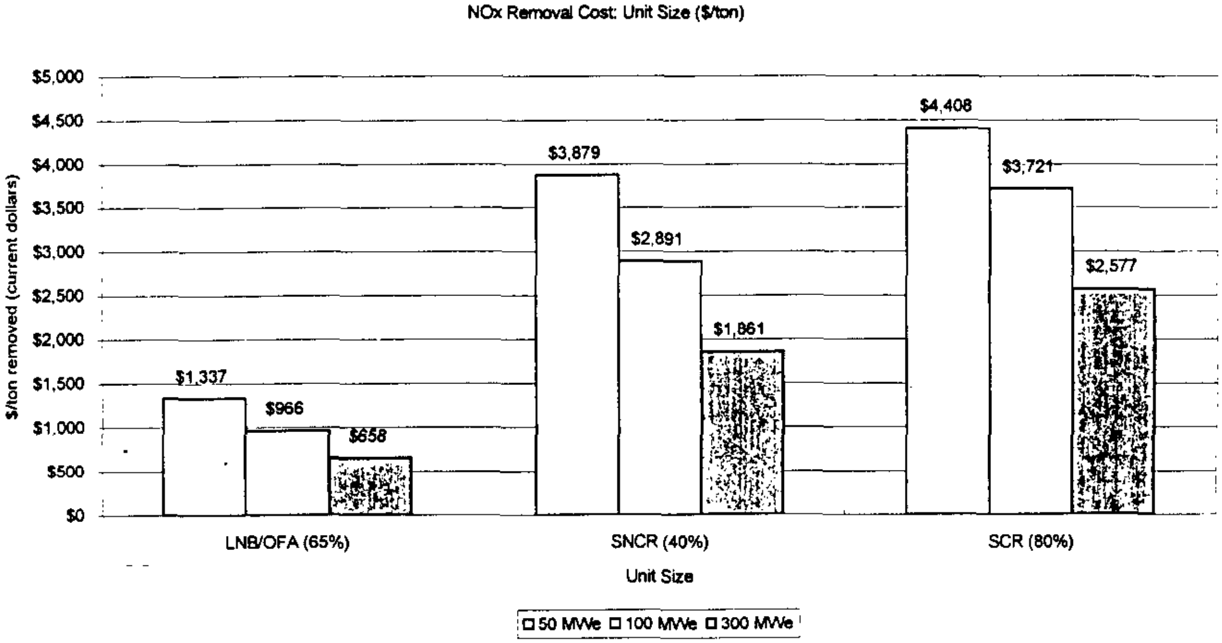

Figure 8-6. Effect of Unit Size on Levelized Cost ($/ton) of NOx Control Systems

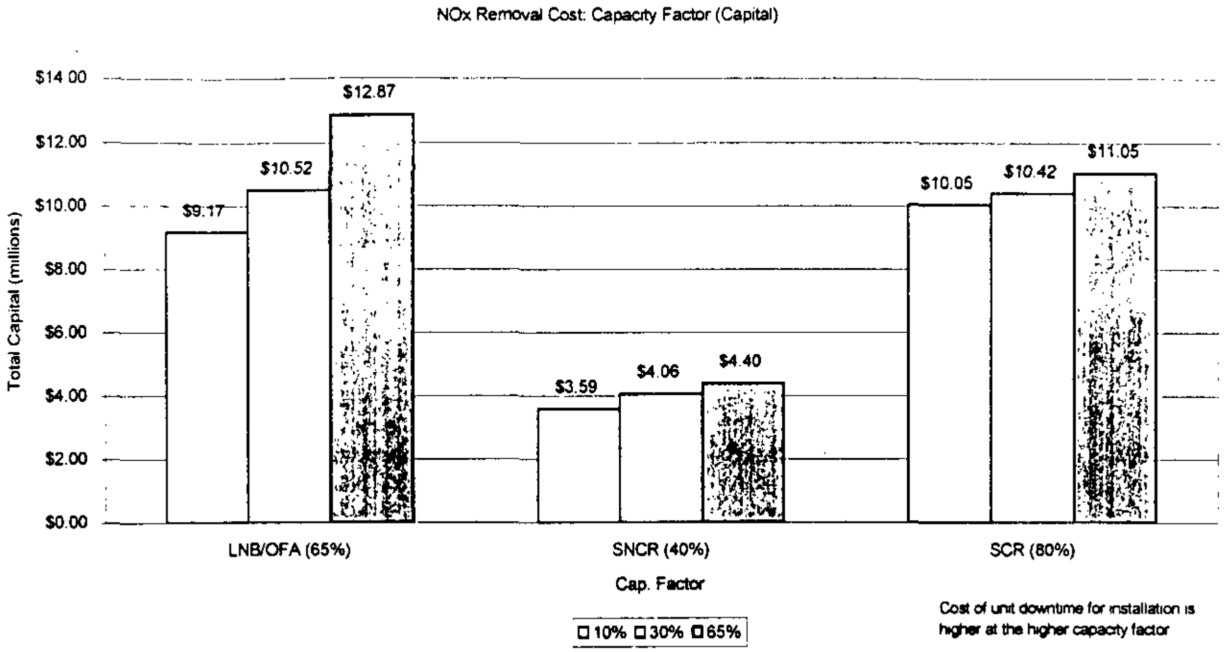

Figure 8-7. Effect of Capacity Factor on Capital Cost of NO_x Control Systems

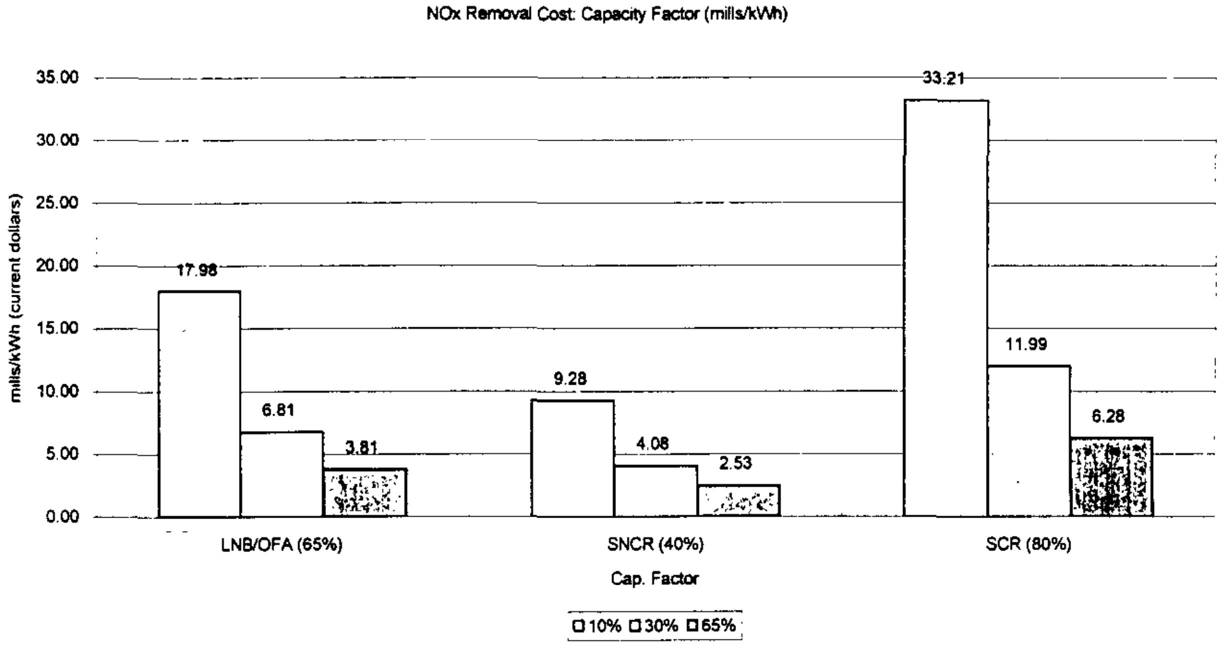

Figure 8-8. Effect of Capacity Factor on Levelized Cost (mills/kW) of NOx Control Systems

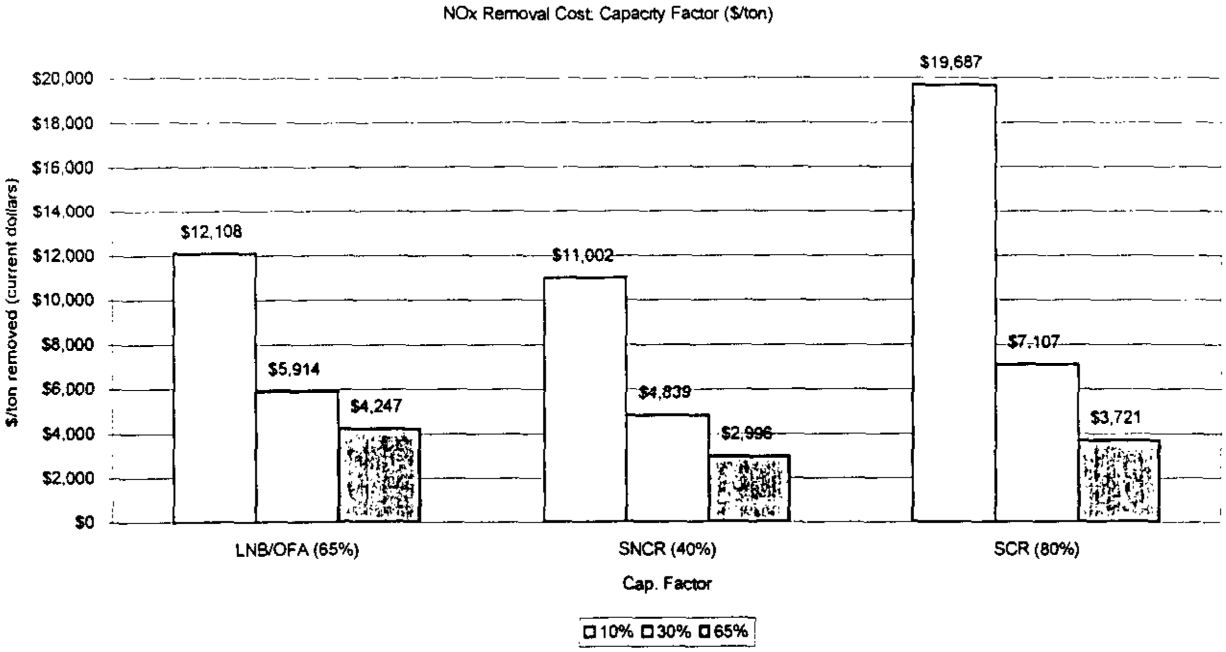

Figure 8-9. Effect of Capacity Factor on Levelized Cost ($/ton) of NO_x Control Systems

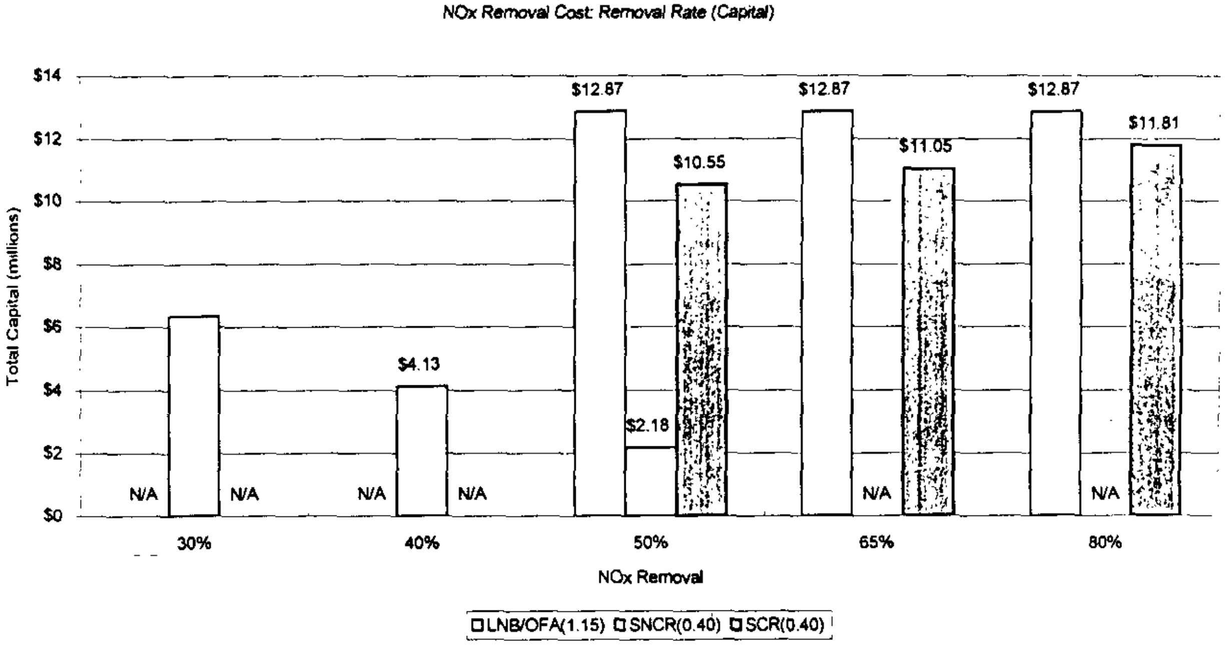

Figure 8-10. Effect of NO_x Removal Rate on Capital Cost of NO_x Control Systems

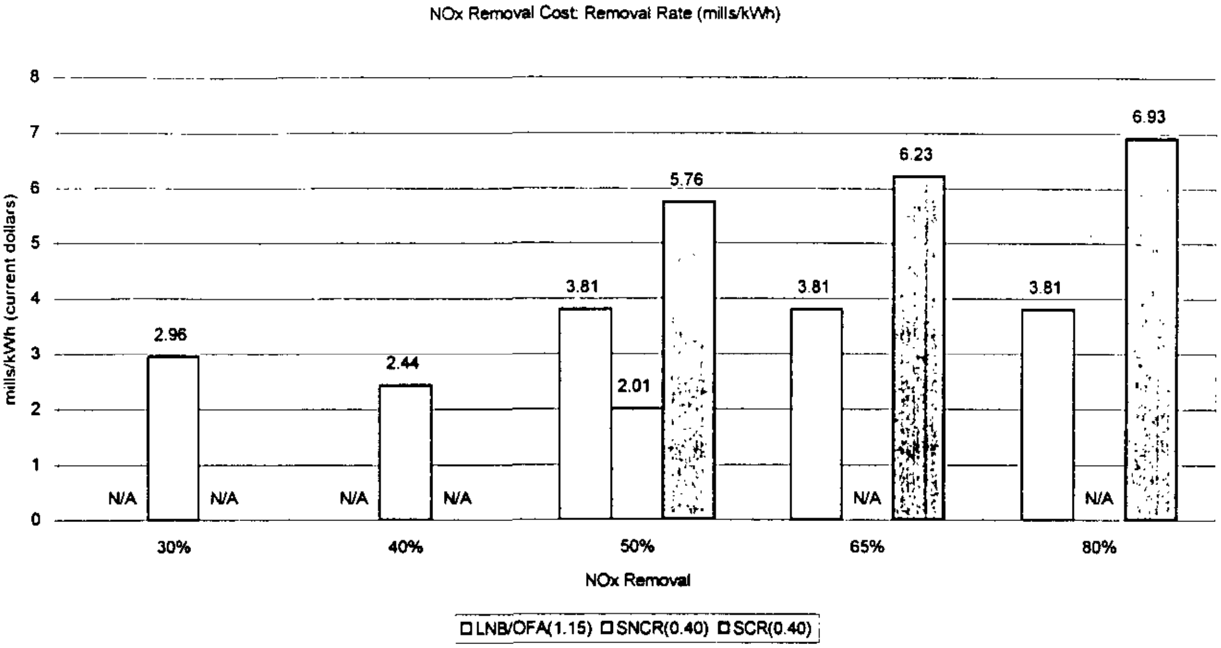

Figure 8-11. Effect of NO_x Removal on Levelized Cost (mills/kW) of NO_x Control

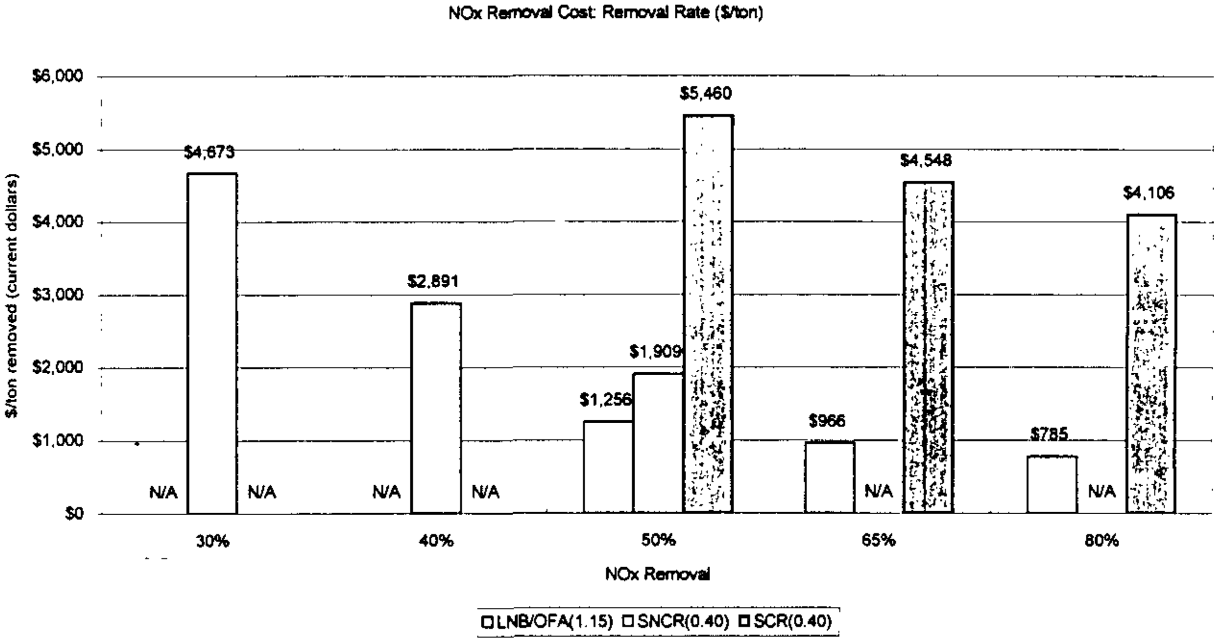

Figure 8-12. Effect of NO_x Removal Rate on Levelized Cost ($/ton) of NO_x Control Systems

8.3 SO_2 Emissions Control Systems

This section describes the effects of varying the sulfur content of the coal, the size of the unit, the capacity factor, and the SO_2 removal rate for the SO_2 emissions control systems.

Figures 8-13 through 8-15 summarize and graph the effects of varying the sulfur content of the coal:

- Figure 8-13 shows the effect on the total capital requirement
- Figure 8-14 shows the effect on the levelized costs (mills/kW).
- Figure 8-15 shows the effect on the levelized costs ($/ton).

Figures 8-16 through 8-18 summarize and graph the effects of varying the size of the unit:

- Figure 8-16 shows the effect on the total capital requirement
- Figure 8-17 shows the effect on the levelized costs (mills/kW).
- Figure 8-18 shows the effect on the levelized costs ($/ton).

Figures 8-19 through 8-21 summarize and graph the effects of varying the capacity factor:

- Figure 8-19 shows the effect on the total capital requirement
- Figure 8-20 shows the effect on the levelized costs (mills/kW).
- Figure 8-21 shows the effect on the levelized costs ($/ton).

Figures 8-22 through 8-24 summarize and graph the effects of varying the SO_2 removal rate of the system:

- Figure 8-22 shows the effect on the total capital requirement
- Figure 8-23 shows the effect on the levelized costs (mills/kW).
- Figure 8-24 shows the effect on the levelized costs ($/ton).

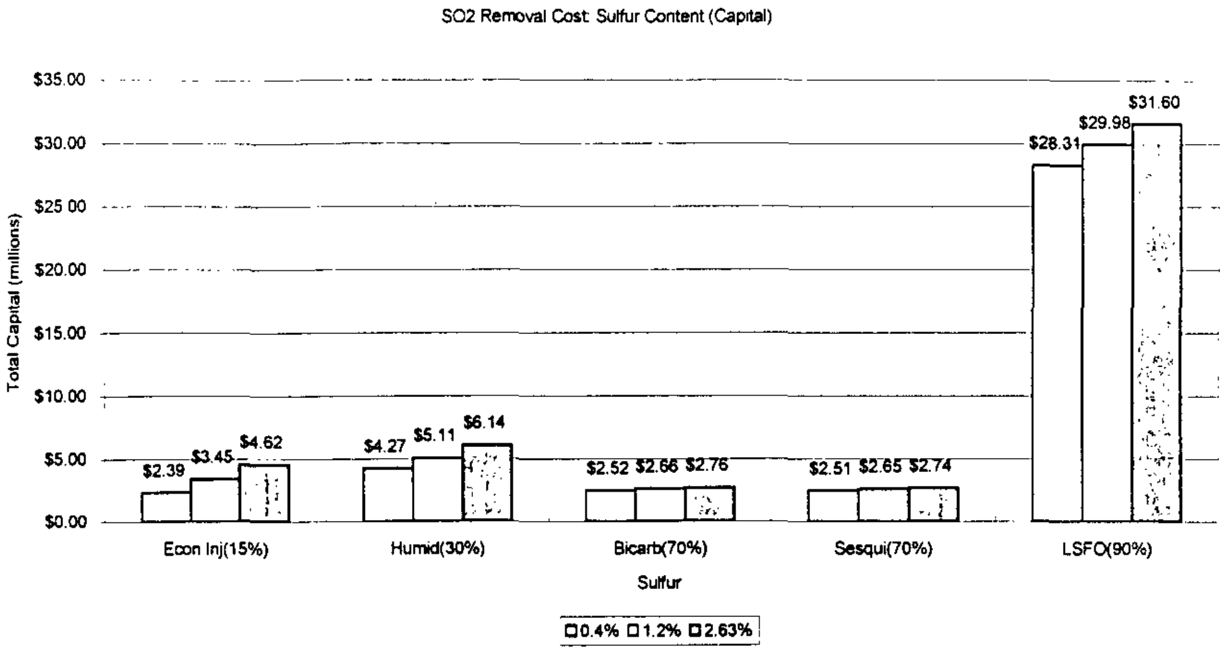

Figure 8-13. Effect of Coal Sulfur Content on Capital Cost of SO_2 Control Systems

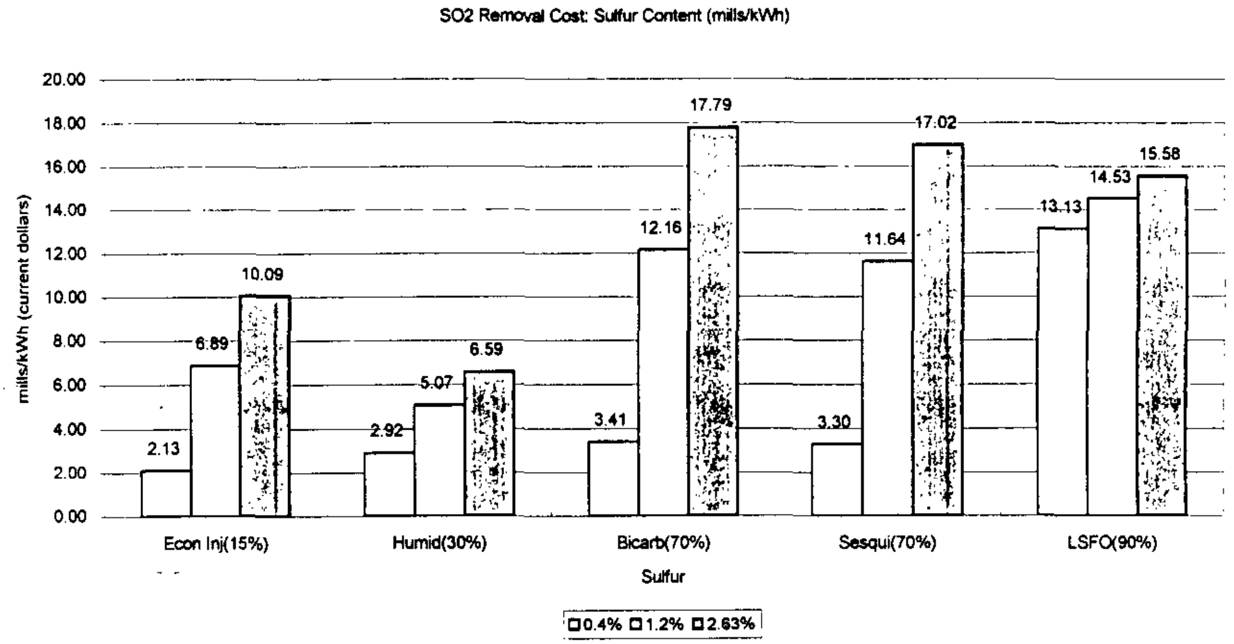

Figure 8-14. Effect of Coal Sulfur Content on Levelized Cost (mills/kW) of SO_2 Control Systems

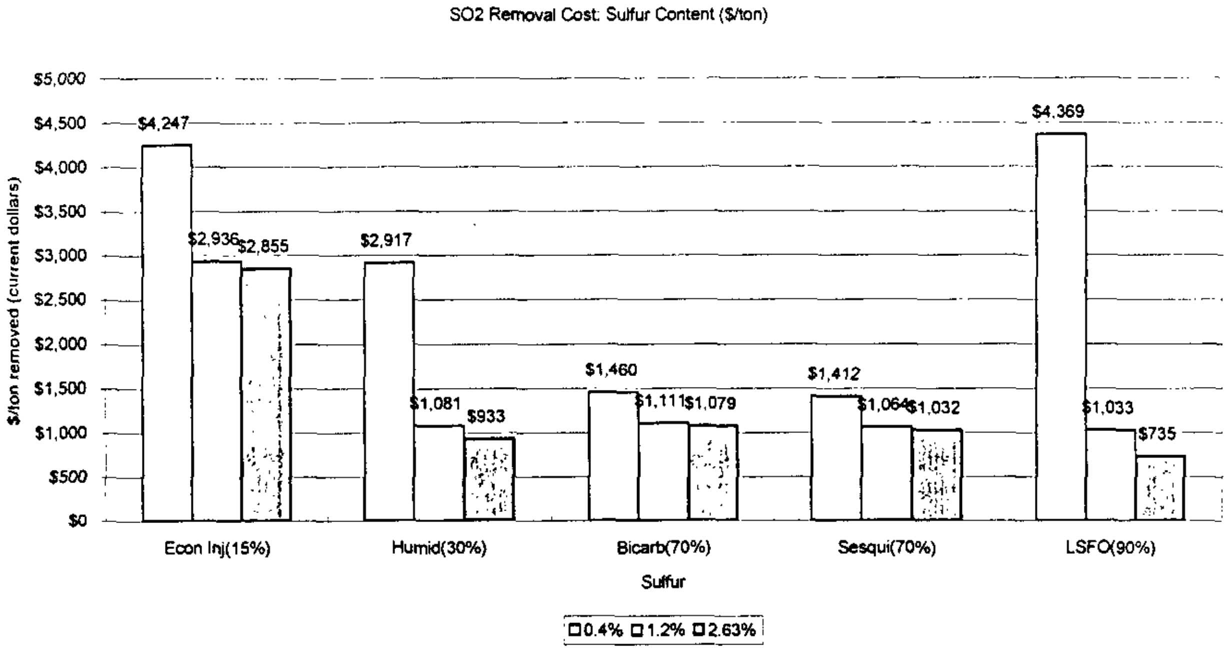

Figure 8-15. Effect of Coal Sulfur Content on Levelized Cost ($/ton) of SO_2 Control

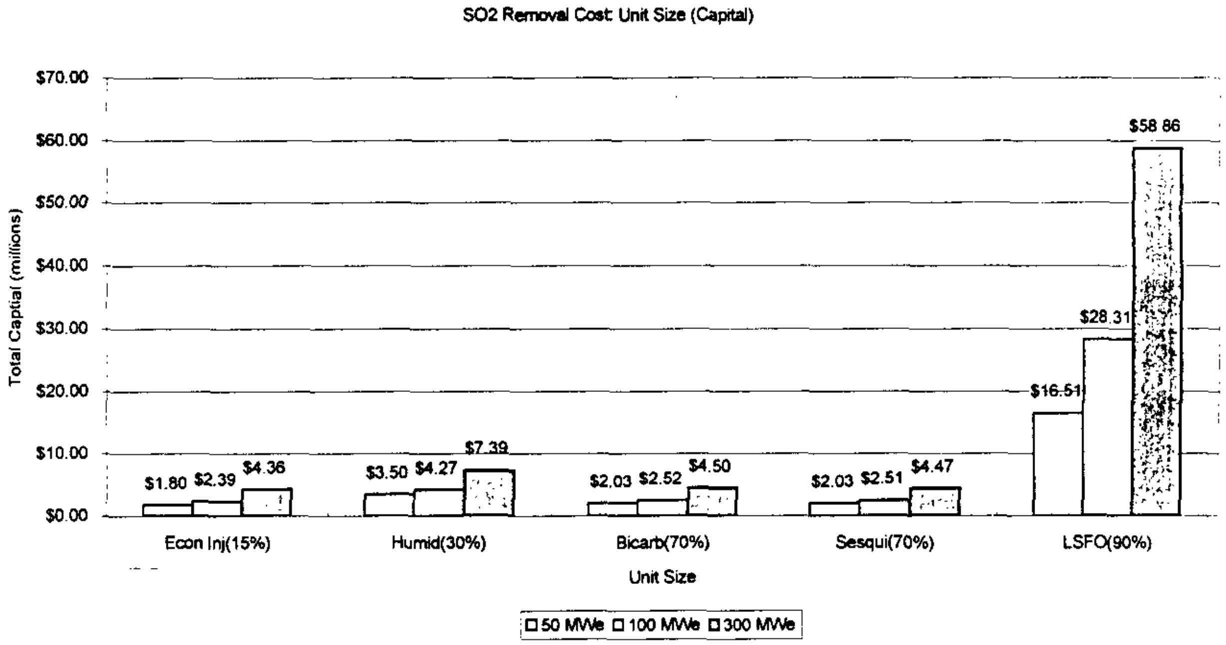

Figure 8-16. Effect of Unit Size on Capital Costs of SO_2 Control Systems

8.4 Integrated NO_x/SO_2 Emissions Control Systems

This section describes the effects of varying the size of the unit and the capacity factor of the integrated systems:

Figures 8-25 through 8-27 summarize and graph the effects of varying the size of the unit:

- Figure 8-25 shows the effect on the total capital requirement
- Figure 8-26 shows the effect on the levelized costs (mills/kW).
- Figure 8-27 shows the effect on the levelized costs ($/ton).

Figures 8-28 through 8-30 summarize and graph the effects of varying the capacity factor:

- Figure 8-28 shows the effect on the total capital requirement
- Figure 8-29 shows the effect on the levelized costs (mills/kW).
- Figure 8-30 shows the effect on the levelized costs ($/ton).

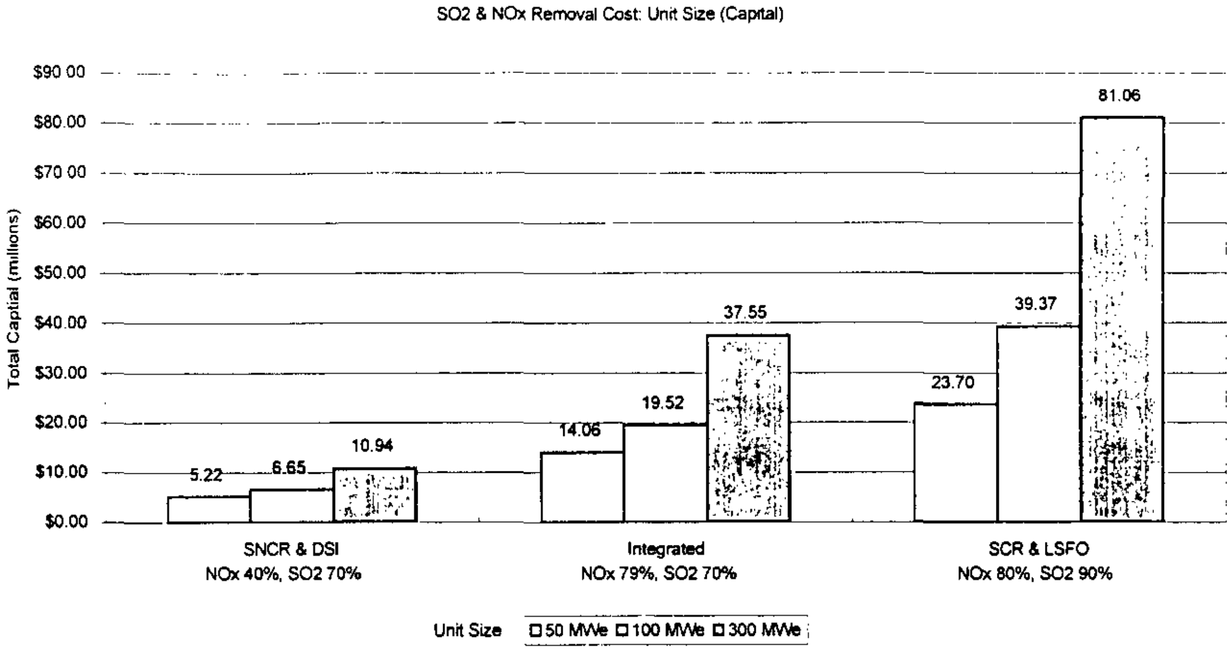

Figure 8-25. Effect of Unit Size on Total Capital Requirements of the Integrated System

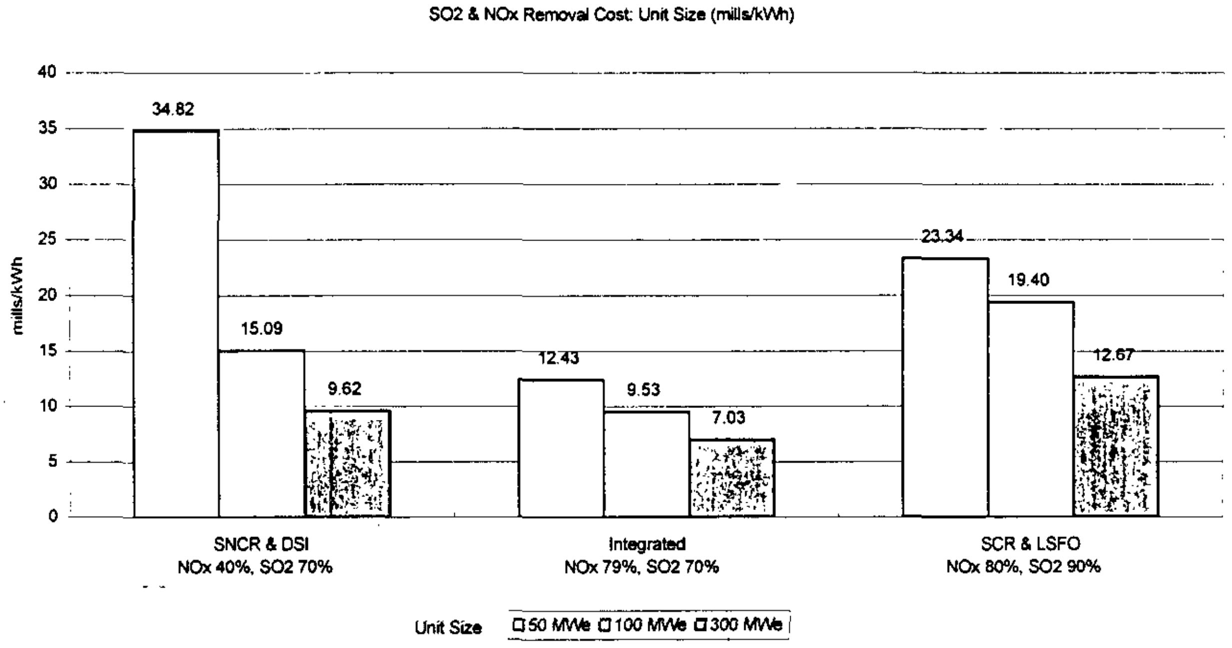

Figure 8-26. Effect of unit Size on Levelized Cost (mills/kW) of the Integrated Systems

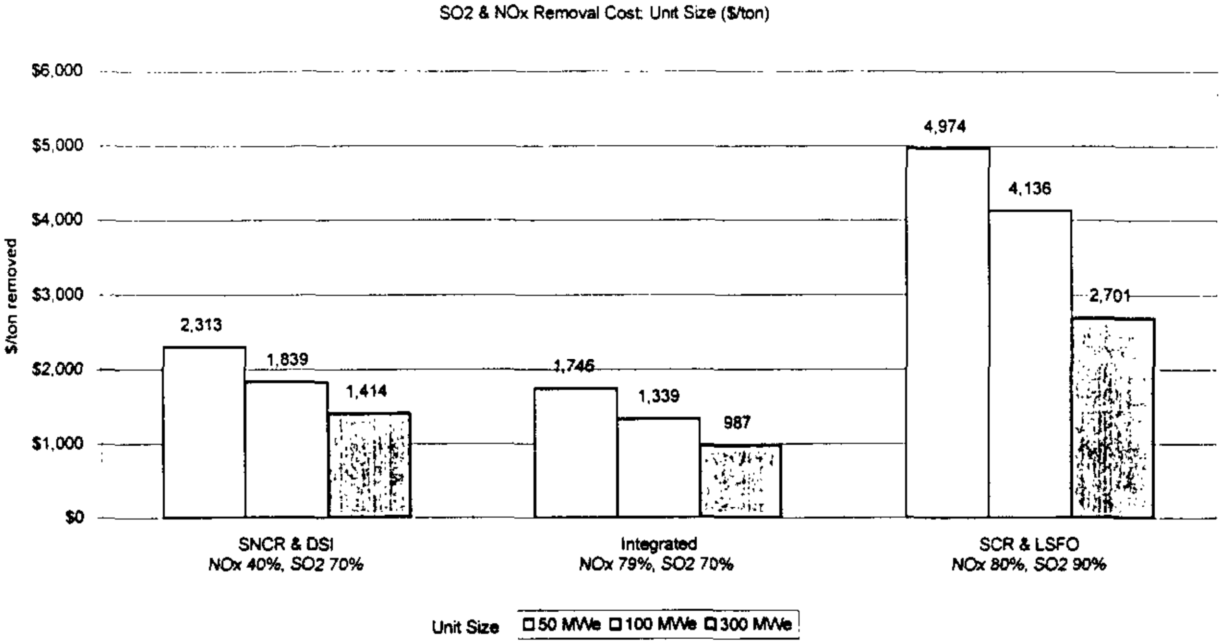

Figure 8-27. Effect of Unit Size on Levelized Cost ($/ton) of the Integrated Systems

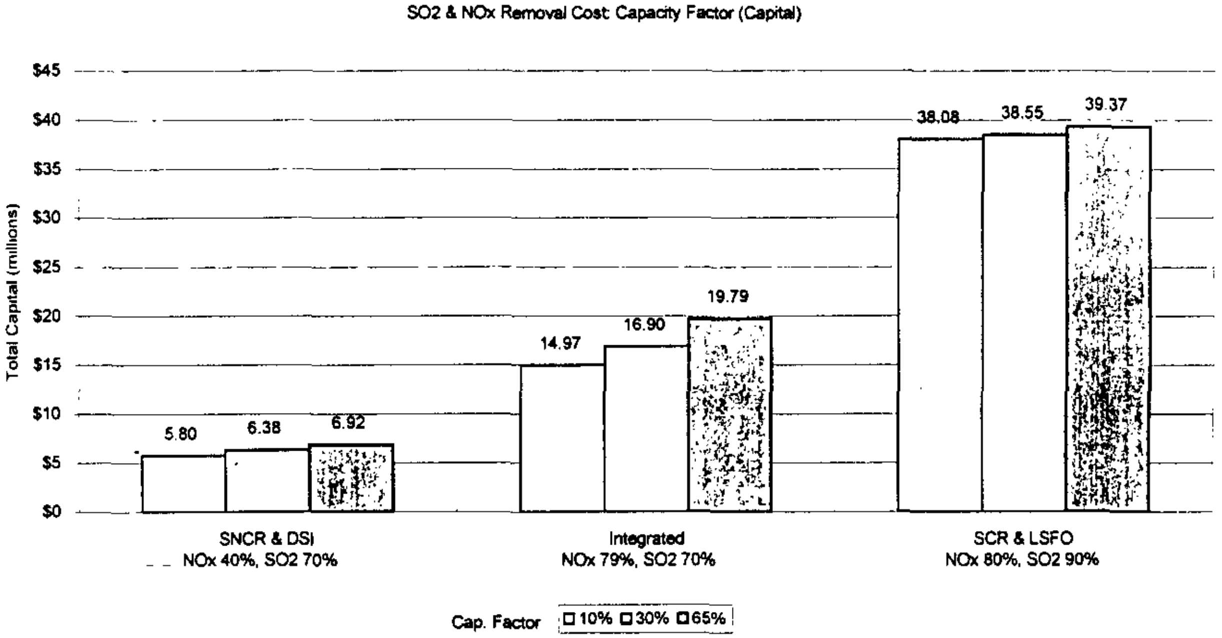

Figure 8-28. Effect of Capacity Factor on Capital Costs of the Integrated Systems

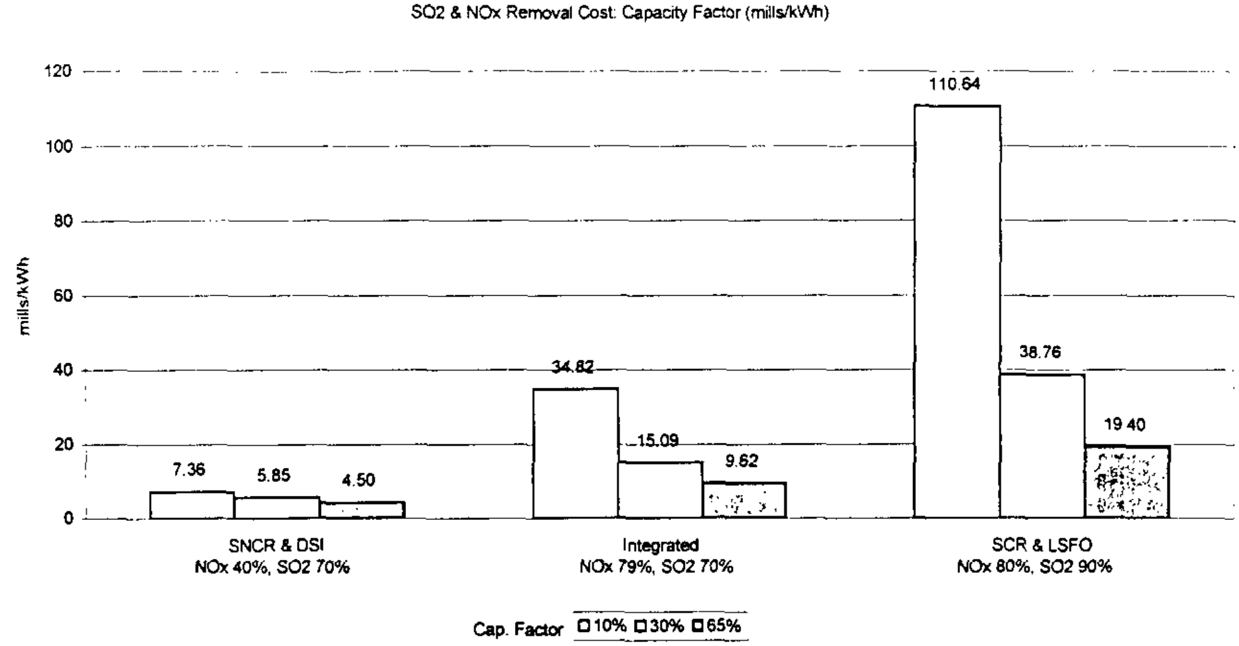

Figure 8-29. Effect of Capacity Factor on Levelized Cost (mills/kW) of the Integrated System

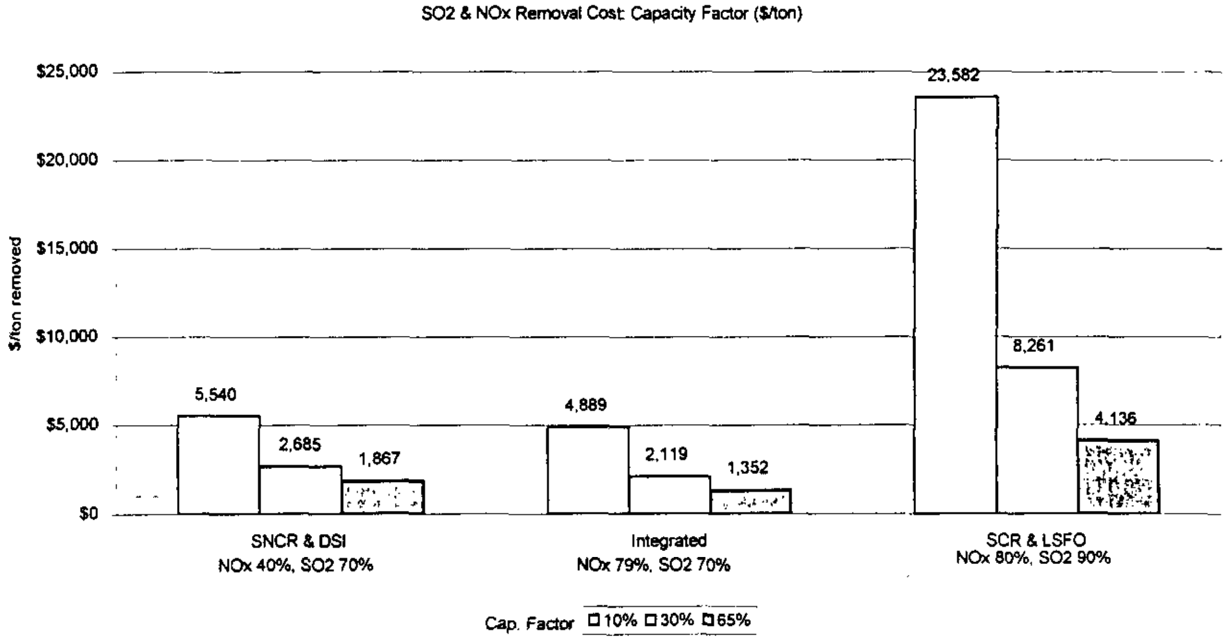

Figure 8-30. Effect of Capacity Factor on Levelized Cost ($/ton) of the Integrated System

9 COMMERCIALIZATION POTENTIAL AND PLANS

This section discusses the commercialization potential of the Integrated Dry NO_x/SO_2 Emission Control System. The entire Integrated Dry NO_x/SO_2 Emission Control System contains a total of five different technologies that were in various stages of commercialization at the time the project was initialized. These technologies are:

- Low NOx Burners
- Overfire Air (NOx Ports)
- Selective Non-Catalytic Reduction
- Dry Sorbent Injection (sodium- and calcium-based injection)
- Duct Humidification (for use with the calcium-base injection)

Public Service Company of Colorado developed and owns the rights to the integration and concurrent use of sodium-based dry sorbent injection and selective non-catalytic reduction. Public Service Company of Colorado was granted a U.S. patent number for the integration of these two technologies. B&W developed and owns the rights to the low NOx Burners, the NOx ports, and the duct humidification technologies. Selective Non-Catalytic Reduction is being marketed by Noell and other vendors in the U.S. and abroad with various proprietary items that vary with each system. Dry sorbent injection is a public domain technology although various proprietary aspects may exist.

9.1 Background

The Integrated Dry NO_x/SO_2 Emission Control System was developed and demonstrated on an older and smaller top-fired B&W boiler burning low-sulfur Western fuel. The goal of this project was to develop and demonstrate a new combination of technologies that could meet future environmental requirements and obtain up to 70% reduction of NO_x and SO_2 emissions. A secondary, but very important, goal of the project was to accomplish these requirements at a lower capital and levelized evaluated cost that the current available technologies.

The project successfully demonstrated that the Integrated Dry NO_x/SO_2 Emission Control System met and even exceeded its emissions removal targets. On similar units it is believed that the system can obtain nearly 80% NO_x reduction while obtain 70% SO_2 reduction. This was accomplished at far lower capital and levelized operating costs than a competing system of SCR and LSFO wet scrubber for a unit burning low sulfur coal.

The environmental control market is driven by the customer's need to meet environmental requirements. Soon after this project was begun, the current Clean Air Act was modified with new requirements for SO_2 and NO_x emissions. The SO_2 emission regulations required significant SO_2 reduction for high sulfur coal unit and overall limiting emissions to those that occurred in the late 1980's. A system of trading SO_2 allowances was created that allows the regulated entities to buy and sell the right to emit SO_2. These new rules allow the "most economic" methods to be used for SO_2 removal. For example, a small unit that had slightly increased SO_2 emissions could be purchase or use SO_2 allowances obtained from another unit that had excess allowances. If the market price of these allowances was sufficently high, some efficient companies could generate additional allowances. The NO_x limits that were set by this program were based on obtaining reductions that can be achieved with combustion modifications.

9.2 Market

The Integrated Dry NO_x/SO_2 Emission Control System was developed to be retrofitted to pre-NSPS boilers that may require moderate (up to 70%) reductions in SO_2 and NO_x emissions. In particular, the Integrated Dry NO_x/SO_2 Emission Control System was developed to meet the site specific requirements for some of the more difficult boiler emission control situations. Market analysis indicates the following units that may have a need for further SO_2 and NO_x reductions:

- Down-fired boilers (6,400 MWe, 65 units), and

- Wet bottom boilers (3,800 MWe, 29 units).

These units generate high levels of NO_x and are difficult to retrofit with existing SO_2 removal technologies because of the age and available expansion area. Other characteristics of this market include:

- The remaining operating units are relatively old with a median age of about 36 years. These types of boilers were popular in the 1930s, 40s, and 50s but have largely been displaced by larger dry bottom wall fired and tangential fired designs.

- The boilers are relatively small, typically ranging from 12 to 225 MWe with an average size of about 100 MWe.

- Many of these coal-fired units are located in the Mid-west.

Because of the age, size, and retrofit difficulty of these units, utilities will be very price sensitive to new equipment. Many utilities are considering fuel switching and retirement for these units. However, the Integrated Dry NO_x/SO_2 Emission Control System provides an economic alternative that can be considered rather than retirement.

A broader secondary market also exists that would benefit from installing one or more of the technologies included in the Integrated Dry NO_x/SO_2 Emission Control System. B&W has installed and has plans to install their low NO_x burners to a large number of wall fired units. Their NO_x ports are expected to be installed on some units that have a desire for further NO_x reductions require by regional, state, or local requirements. Selective Non-Catalytic Reduction will be attractive to units that have retrofit low NO_x combustion modifications but have further requirements to reduce NO_x emissions. The sorbent injection technology is expected to be attractive where moderate reductions in SO_2 are needed on low to moderate sulfur coal boilers as a SO_2 trim system on units that may choose a lower sulfur coal to meet regulatory requirements. This secondary market includes power plants that have the following characteristics:

- Coal-fired, pre-NSPS units
- Coal sulfur emission greater than 1.2 lb/MMBtu
- Units with fabric filters
- Units with electrostatic precipitators with SCA ratings greater than 400.
- Units with ESPs with SCAs between 300 and 400. (site specific due to higher particulate loads)

An evaluation of pre-NSPS boilers with these characteristics indicates that the following secondary markets may exist for the Integrated Dry NO_x/SO_2 Emission Control System SO_2 removal technologies.

• ESP (SCA>400)	38,000 MWe, 126 units
• ESP (300<SCA<400)	29,200 MWe, 100 units
• Fabric Filters	4,400 MWe, 38 units

9.3 Commercialization Status

The market analysis shows there is a significant potential for a lower capital and levelized cost method of obtaining significant NO_x and SO_2 emission reductions. However, early indications are that many utilities are considering fuel switching and low NO_x burners alone to meet the requirements of the Clean Air Act. When major SO_2 reductions are being considered, this is generally on large units that fire a high sulfur coal. In these cases, wet scrubbers generally provide the most economical method of reduction. In certain areas where higher SO_2 and/or NO_x removals are being considered, technologies that provide the maximum removal capability are being considered although they often have a higher evaluated cost for removal than the

Integrated Dry NO_x/SO_2 Emission Control System . The environmental groups and regulatory agencies are demanding that SO_2 and NO_x removals be obtained at technology limits rather than by the most economical means. This desire for increasing reductions has lessened the market expectations for technologies such as the Integrated Dry NO_x/SO_2 Emission Control System that obtain lower but more economic removals than obtained by competing technologies.

Despite the lower market expectation of the Integrated Dry NO_x/SO_2 Emission Control System, there remain a number of units that would benefit at the removal rates possible with this system. Public Service Company of Colorado intends to continue market exposure of the Integrated Dry NO_x/SO_2 Emission Control System in those cases where the benefits of the system can be maximized. Public Service is studying installing all or parts of the Integrated Dry NO_x/SO_2 Emission Control System on a number of their units depending on future environmental requirements. B&W has a large market share in the environmental control industry and is exposing potential customers to those parts of the Integrated Dry NO_x/SO_2 Emission Control System that meet specific requirements for cost and removal.

10 SUMMARY AND CONCLUSIONS

The Integrated Dry NO_x/SO_2 Emission Control System is a new emission control technology that consists of the integration of five existing and developing technologies as follows:

- Low NOx Burners
- Overfire Air (NOx Ports)
- Selective Non-Catalytic Reduction
- Dry Sorbent Injection (sodium- and calcium-based injection)
- Duct Humidification (for use with the calcium-base injection)

The combined system achieved an 80% NO_x reduction and a 70% SO_2 reduction when demonstrated on Public Service Company of Colorado's Arapahoe Unit 4. Arapahoe Unit 4 is a 100 MWe coal-fired unit located in Denver burning low-sulfur (0.4%) Colorado coal. The system, with the exception of the combustion modifications, can be retrofit to a large range of units of varying boiler types with minimal outage time and at a lower capital cost than existing technologies. Advantages of the Integrated Dry NO_x/SO_2 Emission Control System are as follows:

- Up to 80% NO_x and 70% SO_2 reductions
- Minimal land area required for retrofit with flexible location selection
- Short outage required for installation
- Application to a number of units regardless of boiler type and particulate control collection device
- No additional solid waste stream
- Integration of the complete system reduces the negative effects of the individual technologies
- Much lower capital cost (roughly 50% lower than a wet scrubber with SCR)
- Lower levelized cost per ton of reduced emission especially on smaller low sulfur coal units (roughly 70% lower than a wet scrubber with SCR on a unit similar to Arapahoe 4)

Disadvantages of the Integrated Dry NO_x/SO_2 Emission Control System are as follows:

- Higher operating and maintenance costs (additional equipment and reagent purchase)
- Slight decrease in boiler efficiency (due to the water injection of the SNCR)
- Stack ammonia emissions of 5 to 10 ppm
- Increase in N_2O emissions (when urea is used as the SNCR reagent)
- Slight increase in NO_2 emissions (with sodium-based reagent)
- Change in waste characteristics (ammonia odor due to SNCR slip)
- Increase in the waste solubility (due to sodium-based injection)
- Inability to achieve higher than 70% SO_2 reduction limits application to meet some regulatory requirements

This DOE Clean Coal Technology project has provided a significant amount of operating data and knowledge on a number of different technologies. A short summary for each of the technologies investigated during this program is presented. Details on the results are available in more depth with the body of this report and the previously published test reports for the project.

10.1 *Low NO_x Burners and Overfire Air*

This project was the first retrofit of low NO_x burners to a utility top-fired boiler. These boilers generally have higher NO_x emissions than the more common wall- and tangentially-fired boilers. These two technologies are discussed together as it is difficult to determine the individual effect of the equipment as both were installed during the same outage.

- The combustion modifications at Arapahoe provided higher than expected NO_x reductions of 62 to 69% across the normal operating range of 50-110 MWe.
- It is believed that the low-NO_x burners provided most of the NO_x reductions, however, due to cooling air requirements, it was not possible to test the system with overfire air quantities of less than 15% of total secondary air flow.

- NO_x emissions during normal load-following conditions were increased by up to 20% from the base load test conditions.

- The combustion modifications did not increase the unburned carbon nor the CO emissions of the boiler during tuned conditions. However, the tuning was accomplished by raising excess air by a net 0.5 to 1.0 % oxygen level at the boiler exit.

- Increasing overfire air flow on this boiler provided significant reductions in both CO and flyash unburned carbon levels. This was contrary to what was expected, and is attributed to increased overfire air penetration and mixing at the higher flow rates.

- The combustion modifications decreased the furnace exit gas temperature by approximately 200°F. This furnace exit gas temperature decreased due to lower waterwall slagging and an associated increased heat absorption in the furnace. Excess air was increased by up to 2% at 60MWe to overcome the lower superheat steam temperatures.

10.2 *Selective Noncatalytic Reduction*

This project was the first U.S. utility coal-fired retrofit of SNCR. The system was tested with both urea and urea converted to ammonia based compounds.

- Urea injection allows an additional 30 to 50% NOx reduction while maintaining an ammonia slip of 10 ppm at the fabric filter inlet during base load operation. Both stationary and retractable injection lances in the furnace were used depending on unit load. This increased the total system NOx reduction to greater than 80% at full load, significantly exceeding the project goal of 70%.

- Boiler load was the parameter which was shown to have the largest effect on system performance, as it was the predominate factor in determining the local flue gas temperature at the injection location.

- Variations in the total liquid flow and mixing air flow had small effects on both NO_x reduction and NH_3 emissions over the range of flows tested.

- Urea injection increased the N_2O emissions by 29 to 35%.

- On an equal ammonia slip basis, converted urea provides higher NO_x removals than urea on this boiler. However, the increased NO_x removals with converted urea required higher chemical injection rates and thus was less efficient.

- Converted urea injection increased the N_2O emission by 3 to 8%.

- The use of retractable furnace lances greatly increased the low load performance of the SNCR system at Arapahoe. At loads below 70MWe the NO_x reduction was increased from 11% with the wall injectors to 35 to 52 percent with the retractable lances.

- Ammonia will absorb on the flyash in the baghouse depending upon the fly ash chemistry. With operation at a 10 ppm NH_3 slip at the fabric filter inlet, ash ammonia concentrations were in the range of 100 to 200 ppm by weight. This quantity did not cause any problems with odor or ash disposal when the SNCR was operated with the sodium injection system out of service.

10.3 *Sodium-Based Dry Sorbent Injection*

Sodium reagent use provided the highest SO_2 removal efficiencies and was shown to be the most economical SO_2 removal system studied at the low sulfur coal fired Arapahoe station. While sodium injection has been studied and used at other sites, a large amount of data was gathered at Arapahoe.

- Both sodium sesquicarbonate and sodium bicarbonate were able to achieve 70% SO2 removal.

- Sodium sesquicarbonate injection worked well over the tested flue gas temperature range of 220 to 280°F before the fabric filter. When injected before the air heater at 650°F, sodium sesquicarbonate injection provided the same final SO_2 removal although the reaction rate was slightly slower than at the cooler temperatures.

- Sodium bicarbonate injection eventually obtained high SO_2 removal when injected before the fabric filter into a 250 to 280°F flue gas. However, the reaction rate was so slow at these temperatures the reagent was not a practical choice for Arapahoe. When injected before the air heater at 650°F, sodium bicarbonate injection provided a much faster reaction and good reagent utilization.

- At 70% SO_2 removal and injection before the air heater, sodium bicarbonate injection required a molar injection ratio (2Na/S) of approximately 0.9. At the same SO_2 removal and injection before the fabric filter, sodium sesquicarbonate injection required a molar injection ratio (2Na/S) of approximately 1.9. As SO_2 removal is reduced the molar injection ratio between the two reagents decreases rapidly.

- Sodium sesquicarbonate utilization increases substantially as particle size is reduced. At a nominal molar injection ratio (2Na/S) of 0.9, 28 micron mean diameter provided 28% SO_2 removal, 17 micron mean diameter provided 42% SO_2 removal, and 15 micron mean diameter provided 48% SO_2 removal.

- Sodium bicarbonate utilization showed a lower dependence upon particulate size. At a nominal molar injection ratio (2Na/S) of 0.9, 25 micron mean diameter provided 58% SO_2 removal while 18 micron mean diameter provided 60% SO_2 removal.

- Humidification of the flue gas to a 60°F approach to saturation increased SO_2 removal by up to 20% when injecting sodium sesquicarbonate (at the same molar ratios).

- Both sodium sesquicarbonate and sodium bicarbonate also produce some NO_x reduction. At a 70% SO_2 removal rate, approximately 10% NO_x reduction is obtained with either reagent. This NO_x reduction varies due to unexplainable conditions and cannot be controlled.

- Both sodium sesquicarbonate and sodium bicarbonate reagents oxidize NO to NO_2. The total NO_x is reduced but the stack NO_2 concentration will increase. As NO_2 is a visible gas, a sufficient concentration (approximately 35 ppm at Arapahoe) will create a visible stack plume.

- Sodium sesquicarbonate creates approximately 50% less NO_2 than sodium bicarbonate at the same SO_2 removal rate.

10.4 *Calcium-Based Dry Sorbent Injection*

Hydrated lime was injected into the boiler in 1000°F flue gas and before the fabric filter in 250°F flue gas. Humidification testing was completed at both injection points. SO_2 removal with calcium-based reagents was substantially less than expected and the removal goal of 50% was not met.

- The highest SO2 removal was obtained with duct injection with humidification to an approach to saturation of 25 to 30°F. At a molar ratio (Ca/S) 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% of the overall SO_2 reduction occurred in the fabric filter.

- Some ash buildup occurred in the duct during humidification although it is believed that this is a manageable effect.

- Only 5 to 10% SO_2 removal was obtained with hydrated lime injection before the economizer at a flue gas temperature of 950 to 1150°F and a molar ratio of 2.0. It is believed that poor reagent distribution was a major cause of the poor performance. A traverse at the boiler outlet showed that even at points near the wall where the local molar ratio was estimated at 6.0, only 30% SO_2 removal was obtained.

- Humidification during economizer injection of hydrated lime did not significantly improve the SO_2 removal. Testing showed that a significant amount of the injected hydrated lime reagent reacted with CO_2 to form calcium carbonate ($CaCO_3$).

10.5 *Integrated System*

The integration of the individual technologies provides some significant advantages although one disadvantage is also discussed.

- The integration of all technologies provided for 80% NOx removal and 70% SO_2 removal at Arapahoe 4.

- A series of four air toxics tests showed that the integrated system when used with a fabric filter successfully removed nearly all the trace metal emissions and approximately 80% of the mercury emissions.

- The integration of sodium-based dry sorbent injection and SNCR decreases the NO_2 emissions that occur with sodium-based injection alone by approximately 50%.

- The integration of sodium-based dry sorbent injection and SNCR decreases NH_3 emissions that occur with SNCR alone although it is difficult to quantify. Through results of the long term test program, it is estimated that a 50% reduction occurred in the NH_3 slip while operating the sodium injection system at a 70% SO_2 removal rate. The net result of the reduced NH_3 emissions was that the control system would automatically increase the urea injected and provide for higher NO_x reductions at the same NH_3 slip. *Conversely, the NH_3 allowable slip could be reduced by 50% while* maintaining the same NO_x removal. Note that these estimates account for the estimated 10% NO_x removal that the sodium injection system provides when operated by itself.

- The flyash ammonia absorption increased during integration of sodium injection and SNCR when operated at the same NH_3 slip. At an 8 ppm NH_3 slip flyash ammonia *ranged from 400 to 700 ppm by weight verses the 100 to 200 ppm by weight that* occurred during SNCR injection alone. One benefit of the integration of the technologies is that as stack ammonia slip decreases, the control system increased urea injection rate and thus provided higher NO_x reduction and intermediate NH_3 slip while operating the sodium injection system. The ammonia was removed from the flue gas but was deposited in the ash. By reducing the allowable NH_3 slip to 4 ppm and maintaining the same NO_x reduction, the ammonia concentration in the ash was reduced to the 100 to 200 ppm by weight range that initially occurred.

- Even at the same flyash ammonia concentration, the NH_3 odor in the ash truck loading area increased and became a concern. It was determined that the rapid pH change that occurred due to the sodium injection caused a more rapid release of the ammonia absorbed in the flyash when it was wetted to control fugitive dust emissions. This problem was eventually solved by transporting the ash in enclosed tanker trucks and not adding water at the site.

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