# INTEGRATED DRY NO$_x$/SO$_2$ EMISSIONS CONTROL SYSTEM

## BASELINE SNCR TEST REPORT

(Test Period: February 4 to March 6, 1992)

DOE Contract Number DE-FC22-91PC90550

Prepared by

R. A. Smith
G. H. Shiomoto
L. J. Muzio
Fossil Energy Research Corp.
Laguna Hills, CA


T. Hunt
Public Service Company of Colorado
Denver, CO

Prepared for

Public Service Company of Colorado
Denver, Colorado

Revised: September 1993

NOV 2 9 1993

Patents Cleared by Chicago on _____

**Public Service**

December 1, 1993

U.S. Department of Energy/PETC
Mail Stop 920L
P.O. Box 10940
Pittsburgh, PA. 15236

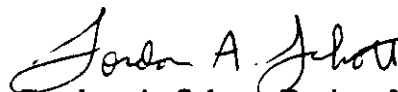Attention: Mr. Thomas W. Arrigoni, PETC Technical Project Manager

Subj:  Integrated Dry NOx/SO2 Emissions Control System
DOE I.D. DE-FC22-91PC90550

Gentlemen:

We are sending herewith the final version of the *Baseline SNCR Test Report*. This final report has been modified to include your previous comments and has received the required patent clearance.

Please advise us if you have any questions.

Very truly yours,

Gordon A. Schott, Project Manager
Environmental Engineering
Generation Engineering Services

Enclosure

<u>With enclosure</u>:

cc:  Mr. David L. Hunter (DOE)            Mr. Dale Jones (Noell)
Dr. C. Lowell Miller (DOE)          Mr. George Brown (PSCC,2)
Mr. Hugh Glen (DOE)                 Mr. Terry Hunt (PSCC)
Mr. Howard Fibus (DOE)              File CC-071G
Mr. Jeffrey Stallings (EPRI)
Mr. Jim Rooney (Coastal Chem)
Mr. John Doyle (B&W)
Office of Technical Information Management (3)
Dr. S.N. Roger Rao (Burns and Roe Technical Group)

DISCLAIMER


This report was prepared by Fossil Energy Research Corporation for Public Service Company of Colorado pursuant to a Cooperative Agreement partially funded by the U.S. Department of Energy, and neither Public Service Company of Colorado, any of its subcontractors, the U.S. Department of Energy, nor any person acting on behalf of either:

    (a)    Makes any warranty or representation, express or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this report, or that the use of any information, apparatus, method or process disclosed in this report may not infringe privately-owned rights; or

    (b)    Assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, method or process disclosed in this report.

Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the U.S. Department of Energy. The views and opinions of authors expressed herein do not necessarily state or reflect those of the U.S. Department of Energy.

# ABSTRACT

The DOE sponsored Integrated Dry $NO_x/SO_2$ Emissions Control System program, which is a Clean Coal Technology III demonstration, is being conducted by Public Service Company of Colorado. The test site is Arapahoe Generating Station Unit 4, which is a 100 MWe, down-fired utility boiler burning a low sulfur western coal. The project goal is to demonstrate 70 percent reductions in $NO_x$ and $SO_2$ emissions through the integration of: 1) down-fired low-$NO_x$ burners with overfire air; 2) Selective Non-Catalytic Reduction (SNCR) for additional $NO_x$ removal; and 3) dry sorbent injection and duct humidification for $SO_2$ removal. The effectiveness of the integrated system on a high-sulfur coal will also be tested.

This report documents the second test phase of the program. This second test phase was comprised of the start up of the SNCR system followed by a brief parametric test series. Time constraints due to the retrofit schedule precluded optimizing the SNCR system. Testing investigated both urea and aqueous ammonia as SNCR chemicals. Other parameters investigated included boiler load, the amount of chemical injected, as well as injection parameters (injection location, amount of mixing air, dilution water flow, and injector orifice sizes).

$NO_x$ removals of nominally 35 percent could be obtained with both chemicals while maintaining ammonia slip levels less than 10 ppm at full load. At higher chemical injection rates (nominal N/NO molar ratios of 1.5 to 2.0), $NO_x$ reductions in the range of 60 to 70 percent were achieved, but with unacceptable levels of $NH_3$ slip. For a given level of $NO_x$ reduction, ammonia slip was lower with aqueous ammonia injection than with urea. The test program also confirmed prior observations that 1) the optimum temperature for $NO_x$ reduction with ammonia is lower than with urea, and 2) $N_2O$ emissions as a by-product of the SNCR process are lower for ammonia compared to urea.

--

# ACKNOWLEDGEMENTS

TABLE OF CONTENTS

## LIST OF FIGURES

# LIST OF TABLES

# LIST OF DEFINITIONS

| | |
|---|---|
| ACFM | Cubic Feet per Minute, gas flow |
| Btu | British Thermal Unit |
| B&W | Babcock & Wilcox |
| CEM | Continuous Emission Monitor |
| CFM | Cubic Feet per Minute |
| CGA | Cylinder Gas Audit Test |
| DOE | U. S. Department of Energy |
| DRB-XCL™ | Dual Register Burner - Axially Controlled Low-$NO_x$ |
| DSCF | Dry Standard Cubic Feet of gas |
| DSCFM | Dry Standard Cubic Feet per Minute of gas |
| fps | Feet per Second |
| gpm | Gallons per Minute |
| EPRI | Electric Power Research Institute |
| HVT | High Velocity Thermocouple, suction pyrometry |
| LCP | Local Control Panel |
| LNB | Low-$NO_x$ Burner |
| MMBtu | 1,000,000 Btu |
| MMD | Mass Mean Diameter |
| MWe | MegaWatts (electrical) |
| MWg | MegaWatts (gross load) |
| N/A | Not Applicable |
| NDIR | Non-Dispersive Infrared |
| NDUV | Non-Dispersive Ultraviolet |
| N/NO | Molar Ratio of Nitrogen Injected (in the SNCR Chemical) to the NO Present in the Flue Gas |
| OFA | Overfire Air |
| PLC | Programmable Logic Control |
| PM | Particulate Matter |
| $PM_{10}$ | Particulate Matter under the 10 micron diameter size |
| ppm | Parts Per Million |

FERCo-7034-R229

# LIST OF DEFINITIONS (Continued)

| | |
|---|---|
| ppmc | Parts Per Million Corrected to 3 percent $O_2$ level |
| PSCC | Public Service Company of Colorado |
| psig | Pounds per Square Inch Gauge |
| RATA | Relative Accuracy Test Audit |
| SCF | Standard Cubic Foot, measured at 1 atmosphere and 60°F |
| SCFM | Standard Cubic Feet per Minute, measured at 1 atmosphere and 60°F |
| SNCR | Selective Non-Catalytic $NO_x$ Reduction |

# EXECUTIVE SUMMARY

This Test Report summarizes the technical activities and results for one phase of a Department of Energy sponsored Clean Coal Technology III demonstration of an Integrated Dry $NO_x/SO_2$ Emissions Control System for coal-fired boilers. The project is being conducted at Public Service Company of Colorado's Arapahoe Generating Station Unit 4 located in Denver, Colorado. The project goal is to demonstrate up to 70 percent reductions in $NO_x$ and $SO_2$ emissions through the integration of existing and emerging technologies including: 1) down-fired low-$NO_x$ burners with overfire air; 2) selective non-catalytic reduction (SNCR) for additional $NO_x$ removal; and 3) dry sorbent injection and duct humidification for $SO_2$ removal.

Due to the number of technologies being integrated, the test program has been divided into the following test activities:

- Baseline tests with the original combustion system

- Baseline tests with the original combustion system and SNCR

- Low-$NO_x$ Burner (LNB)/Overfire Air (OFA) tests

- LNB/OFA/SNCR tests

- LNB/OFA/Calcium Injection tests

- LNB/OFA/Sodium Injection tests

- LNB/OFA/SNCR/Dry Sorbent Injection tests (integrated system)

- High-Sulfur Coal tests with the integrated system

The tests with the SNCR and original combustion systems are the subject of this report. The objectives of these tests were twofold. First, to start up and check out the functional performance of the SNCR hardware. Second, to provide a preliminary characterization of the SNCR process performance with the original combustion system. This characterization will then serve as a basis of comparison of the combined LNB/OFA/SNCR system to the use of SNCR alone.

The baseline SNCR test program was conducted over a five (5) week period from February 4, 1992, to March 6, 1992. The short time period did not allow a complete optimization of the injection system. In fact, a detailed optimization was not desirable, as the combustion

FERCo-7034-R229

modifications scheduled for April and May, 1992, were expected to impact operation of the boiler, and therefore change the optimal SNCR operating parameters. A limited parametric investigation of the effects of boiler load, chemical injection rate, and injection system parameters (i.e., injection location, mixing air and dilution water flow rates, and injection nozzle orifice sizes) was accomplished during the five-week period. The injection system parameters were optimized while utilizing urea as the SNCR chemical. The effects of boiler load and chemical injection rate were then assessed for both urea and aqueous ammonia ($NH_4OH$) injection.

The parameters found to have the greatest effect on process performance were boiler load, chemical injection rate (N/NO molar ratio), and mixing air and dilution water flow rates. The effects of mixing air and liquid orifice sizes were found to be minimal. Although mixing air flow rate had only a slight effect on $NO_x$ removal, large increases in $NH_3$ emissions resulted from decreased mixing air flow rates. Variations in boiler load and dilution water flow showed the largest effects on system performance, due to their impact on the local flue gas temperatures in the area of chemical injection. SNCR is a highly temperature dependent process with only a narrow window available for maximum $NO_x$ removal.

As expected, increased SNCR chemical flow rates yielded higher $NO_x$ removals, with the tradeoff of higher $NH_3$ emissions accompanying the increased removals. The results showed that $NO_x$ removals were higher with urea than with $NH_4OH$ for a given chemical injection rate, over nearly the entire boiler load range. $NH_3$ emissions were also found to be higher with urea. Therefore, for a given $NH_3$ emission limit, $NH_4OH$ injection tended to provide higher $NO_x$ removals than urea. As shown in Figure S-1, for a 10 ppm $NH_3$ emission limit $NO_x$ removals of 26 to 36 percent were achievable with $NH_4OH$ over the load range of 60 to 100 MWe, while urea injection resulted in removals of only 16 to 36 percent. However, over the load range of 65 to 100 MWe, urea was the most efficient chemical since the increased $NO_x$ removals with $NH_4OH$ required higher chemical feed rates.

Consistent with previous studies, nitrous oxide ($N_2O$) emissions with $NH_4OH$ injection were lower than with urea injection. With $NH_4OH$, the fraction of the $NO_x$ reduced which was converted to $N_2O$ was less than 2 percent at a nominal N/NO molar ratio of 1.0, irrespective of load. With urea and a similar N/NO ratio, the conversion ranged from 9 to 15 percent at 100 and 60 MWe, respectively.

In addition to byproduct emission of $NH_3$ and $N_2O$, it was also found that the SNCR process increased CO emissions. The increase in CO emissions with $NH_4OH$ injection was found to be lower than that for urea injection. With $NH_4OH$, the increase in CO emissions was on the order of 8 ppm at a nominal N/NO molar ratio of 1.0, irrespective of load. With urea and a similar N/NO ratio, the increase in CO emissions ranged from 10 to 40 ppm at 100 and 60 MWe, respectively.

The above comparisons of the performance of urea and $NH_4OH$ are for injection through the same set of injectors, and for the same set of injection conditions (mixing air and dilution water flow rates). The conclusions may not apply to a system that has been independently optimized for the two different SNCR chemicals.
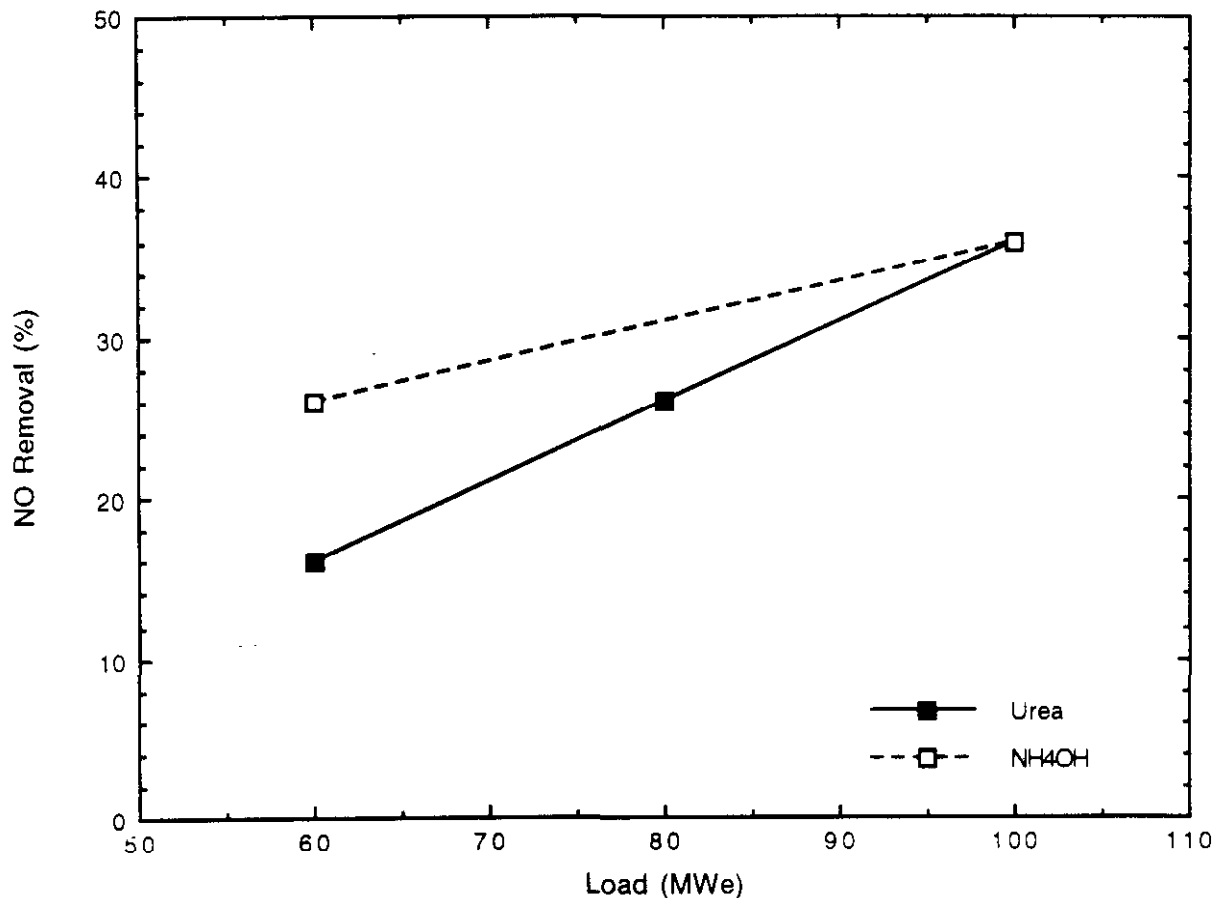
Figure S-1. Comparison of NO Removals for Urea and $NH_4OH$
for a Fixed $NH_3$ Slip Level of 10 ppm

# 1.0 INTRODUCTION

This report presents the results for one phase of the Public Service Company of Colorado (PSCC) and the Department of Energy (DOE) sponsored Integrated Dry $NO_x/SO_2$ Emissions Control System program. This DOE Clean Coal Technology III demonstration program is being conducted by Public Service Company of Colorado at PSCC's Arapahoe Generating Station Unit 4, located in Denver, Colorado. The intent of the demonstration program at Arapahoe Unit 4 is to achieve up to 70 percent reductions in $NO_x$ and $SO_2$ emissions through the integration of existing and emerging technologies, while minimizing capital expenditures and limiting waste production to dry solids that are handled with conventional ash removal equipment. The technologies to be integrated are: 1) a down-fired low-$NO_x$ burner system with overfire air; 2) Selective Non-Catalytic Reduction (SNCR) with urea and aqueous ammonia for additional $NO_x$ removal; and 3) dry sorbent injection (calcium- and sodium-based compounds) and duct humidification for $SO_2$ removal. Figure 1-1 shows a simplified schematic of the integrated system as implemented at Arapahoe Unit 4.

During the demonstration program, these emissions control systems are being optimized and integrated with the goal of achieving up to 70 percent reductions in $NO_x$ and $SO_2$. It is anticipated that the emissions control system will achieve these reductions at costs lower than other currently available technologies. It is also anticipated that these technologies will integrate synergistically. For example, an undesirable side effect of sodium-based sorbent injection for $SO_2$ control has been oxidation of NO to $NO_2$, resulting in plume colorization. Pilot-scale testing sponsored by the Electric Power Research Institute (EPRI) has shown that $NH_3$ can suppress the NO to $NO_2$ oxidation. In this integrated system, the by-product $NH_3$ emissions from the urea injection system will serve to minimize $NO_2$ formation. An additional objective of this program will be to test the effectiveness of the integrated system on a high-sulfur coal.

Due to the number of technologies being integrated, the test program has been divided into the following test activities:

- Baseline tests of the original combustion system. These results provide the basis for comparing the performance of the individual technologies as well as that of the integrated system. (completed)
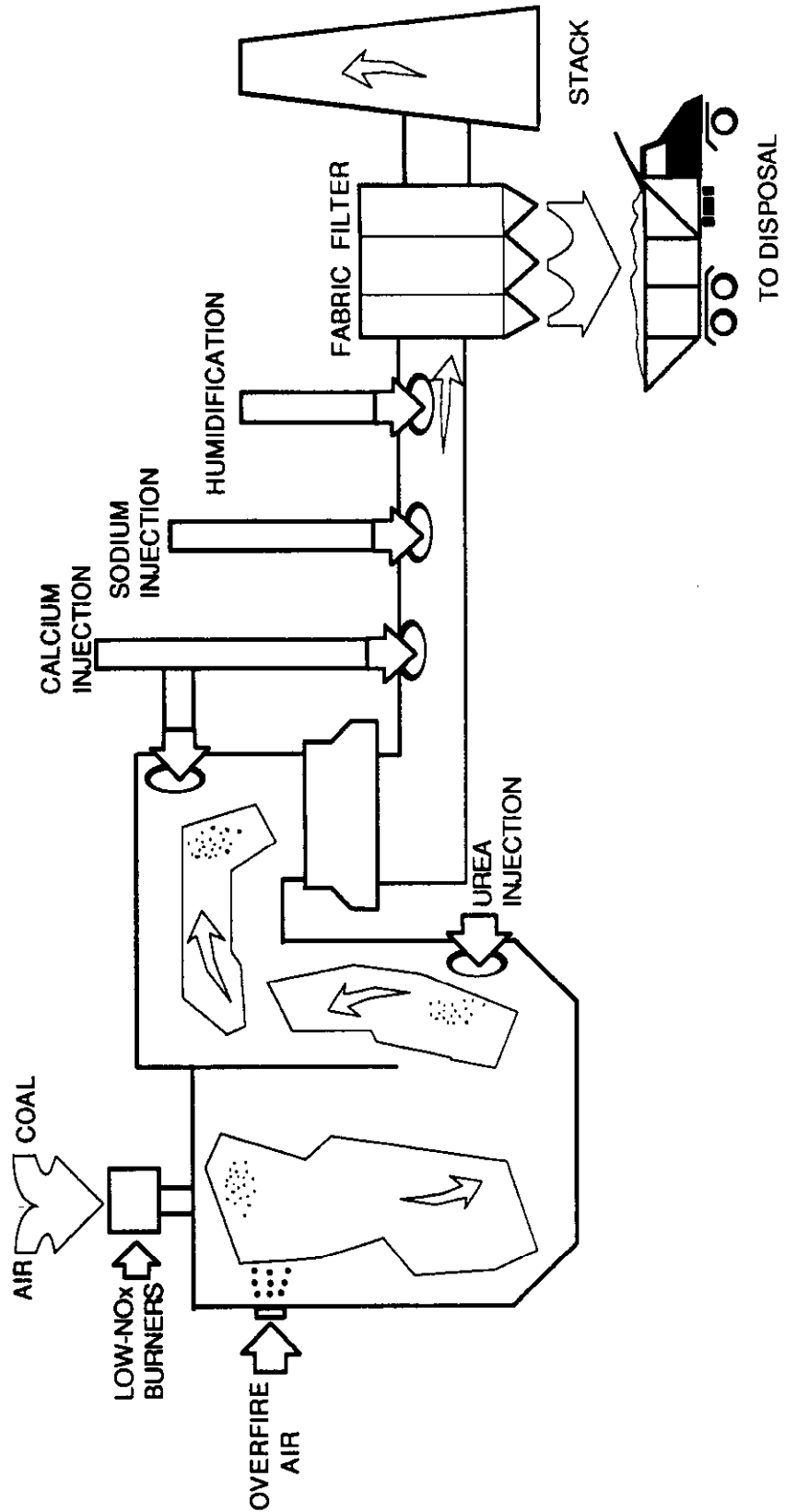
Figure 1-1. Arapahoe Unit 4 Integrated Dry NO$_x$/SO$_2$ Emissions Control System

FERCo-7034-R229

- Baseline combustion system/SNCR tests. Performance of urea and aqueous ammonia injection with the original combustion system. (subject of this report)

- Low-NO$_x$ burner (LNB)/overfire air (OFA) tests.

- LNB/OFA/SNCR tests. NO$_x$ reduction potential of the combined low-NO$_x$ combustion system and SNCR.

- LNB/OFA/Calcium-Based Sorbent Injection. Economizer injection and duct injection with humidification.

- LNB/OFA/Sodium Injection. SO$_2$ removal performance of sodium-based sorbent.

- Integrated Systems test. NO$_x$ and SO$_2$ reduction potential of the integrated system using LNB/OFA/SNCR/dry sorbent injection using calcium- or sodium-based reagents. Integrated system performance.

- High-Sulfur Coal tests. NO$_x$ and SO$_2$ reduction potential of the integrated system using an eastern bituminous coal. Dry sorbent injection will be calcium-based, using the most efficient injection location determined from previous testing.

In addition to investigation of NO$_x$ and SO$_2$, the test program will also investigate air toxic emissions. Baseline air toxic emission levels will be obtained during the testing of the modified combustion system. Three additional tests will be conducted during the urea, calcium, and sodium injection tests to determine the potential air toxics removal of these pollution control technologies.

This report presents the results of the Selective Non-Catalytic Reduction tests performed with the original combustion system on the Arapahoe Unit 4 boiler. During this test period, both urea and aqueous ammonia were investigated as SNCR chemicals.

# 2.0 PROJECT DESCRIPTION

The following subsections will describe the key aspects of the technologies being demonstrated, the project participants, and the boiler and the original combustion system. Finally, a brief review of the results of the baseline tests with the original combustion system will be presented.

## 2.1 PROCESS DESCRIPTION

The Integrated Dry $NO_x$/$SO_2$ Emissions Control system consists of five major control technologies that are combined to form an integrated system to control both $NO_x$ and $SO_2$ emissions. $NO_x$ reduction is accomplished through the use of low-$NO_x$ burners, overfire air, and SNCR, while dry sorbent injection (using either calcium- or sodium-based reagents) is used to control $SO_2$ emissions. Flue gas humidification will be used to enhance the $SO_2$ removal capabilities of the calcium-based reagents. Each of these technologies is discussed briefly below.

### Low-NO$_x$ Burners

$NO_x$ formed during the combustion of fossil fuels consists primarily of $NO_x$ formed from fuel bound nitrogen, and thermal $NO_x$. $NO_x$ formed from fuel bound nitrogen results from the oxidation of nitrogen which is organically bonded to the fuel molecules. Thermal $NO_x$ forms when nitrogen in the combustion air dissociates and oxidizes at flame temperatures. Thermal $NO_x$ is of primary importance at temperatures in excess of 2800°F.

To reduce the $NO_x$ emissions formed during the combustion process, Babcock and Wilcox (B&W) Dual Register Burner-Axially Controlled Low-$NO_x$ (DRB-XCL™) burners were retrofit to the Arapahoe Unit 4 boiler. Most low-$NO_x$ burners reduce $NO_x$ through the use of air staging, which is accomplished by limiting the availability of air during the early stages of combustion. This lowers the peak flame temperature and results in a reduction in the formation of thermal $NO_x$. In addition, by reducing the oxygen availability in the initial combustion zone, the fuel-bound nitrogen is less likely to be converted to $NO_x$, but rather to $N_2$ and other stable nitrogen compounds. The B&W DRB-XCL™ burner achieves increased $NO_x$ reduction effectiveness by incorporating fuel staging in addition to air staging. Fuel staging involves the introduction of fuel downstream of the flame under fuel-rich conditions. This results in the generation of hydrocarbon radicals which further reduce $NO_x$ levels. The fuel staging is accomplished through the design

of the coal nozzle/flame stabilization ring on the burner. Additionally, combustion air to each burner is accurately measured and regulated to provide a balanced fuel and air distribution for optimum $NO_x$ reduction and combustion efficiency. Finally, the burner assembly is equipped with two sets of adjustable spin vanes which provide swirl for fuel/air mixing and flame stabilization.

## Overfire Air

Low-$NO_x$ burners and overfire air reduce the formation of $NO_x$ by controlling the fuel/air mixing process. While low-$NO_x$ burners control the mixing in the near burner region, overfire air controls the mixing over a larger part of the furnace volume. By diverting part of the combustion air to a zone downstream of the burner, initial combustion takes place in a near stoichiometric or slightly fuel rich environment. The remaining air necessary to ensure complete combustion is introduced downstream of the primary combustion zone through a set of overfire air ports, sometimes referred to as $NO_x$ ports. Conventional single jet $NO_x$ ports are not capable of providing adequate mixing across the entire furnace. The B&W dual-zone $NO_x$ ports, however, incorporate a central zone which produces an air jet that penetrates across the furnace and a separate outer zone that diverts and disperses the air in the area of the furnace near the $NO_x$ port. The central zone is provided with a manual air control disk for flow control, and the outer zone incorporates manually adjustable spin vanes for swirl control.

The combined use of the low-$NO_x$ burners and overfire air is expected to reduce $NO_x$ emissions by up to 70 percent.

## Selective Non-Catalytic Reduction

$NO_x$ reduction in utility boilers can also be accomplished by Selective Non-Catalytic Reduction (SNCR). This process involves the injection of either urea or ammonia (anhydrous or aqueous) into the combustion products where the gas temperature is in the range of 1600 to 2100°F. In this range, $NH_2$ is released from the injected chemical which then selectively reacts with NO in the presence of oxygen, forming primarily $N_2$ and $H_2O$. An SNCR system is capable of removing 40 to 50 percent of the NO from the flue gas stream.

Urea and ammonia each have their own optimum temperature and range within which $NO_x$ reduction can occur. An example of such a temperature "window" is shown conceptually in

Figure 2-1. At temperatures above the optimum, the injected chemical will react with $O_2$ forming additional $NO_x$, thereby reducing the $NO_x$ removal efficiency. At temperatures below the optimum, the injected chemical does not react with NO, resulting in excessive emissions of $NH_3$ (referred to as ammonia slip). Chemical additives can be injected with the urea to widen the optimum temperature range and minimize $NH_3$ emissions.

The SNCR chemical of primary interest for the present program is urea. The urea is generally injected into the boiler as a liquid solution through atomizers. The atomizing medium can be either air or steam, although air is used in the current installation. The urea and any additives are stored as a liquid and pumped into the injection atomizers.

## Dry Reagent SO_2 Removal System

The dry reagent injection system consists of equipment for storing, conveying, pulverizing and injecting calcium- or sodium-based products into the flue gas between the air heater and the particulate removal equipment, or calcium products between the economizer and the air heater. The $SO_2$ formed during the combustion process reacts with the calcium or sodium-based reagents to form sulfates and sulfites. These reaction products are then collected in the particulate removal equipment together with the flyash and any unreacted reagent and removed for disposal. The system is expected to remove up to 70 percent of the $SO_2$ when using sodium-based products while maintaining high sorbent utilization.

Although dry sodium-based reagent injection systems reduce $SO_2$ emissions, $NO_2$ formation has been observed in some applications. $NO_2$ is a red/brown gas; therefore, a visible plume may form as the $NO_2$ in flue gas exits the stack. Previous pilot-scale tests have shown that ammonia slip from urea injection reduces the formation of $NO_2$ while removing the ammonia which would otherwise exit the stack.

In certain areas of the country, it may be more economically advantageous to use calcium-based reagents, rather than sodium-based reagents, for $SO_2$ removal. $SO_2$ removal using calcium-based reagents involves dry injection of the reagent into the furnace at a point where the flue gas temperature is approximately 1000°F. Calcium-based materials can also be injected into the flue gas duct work downstream of the air heater, but at reduced $SO_2$ removal effectiveness.

Temperature
too Low

Temperature
too High

NH3
Emissions

NOx
Removal

Optimum
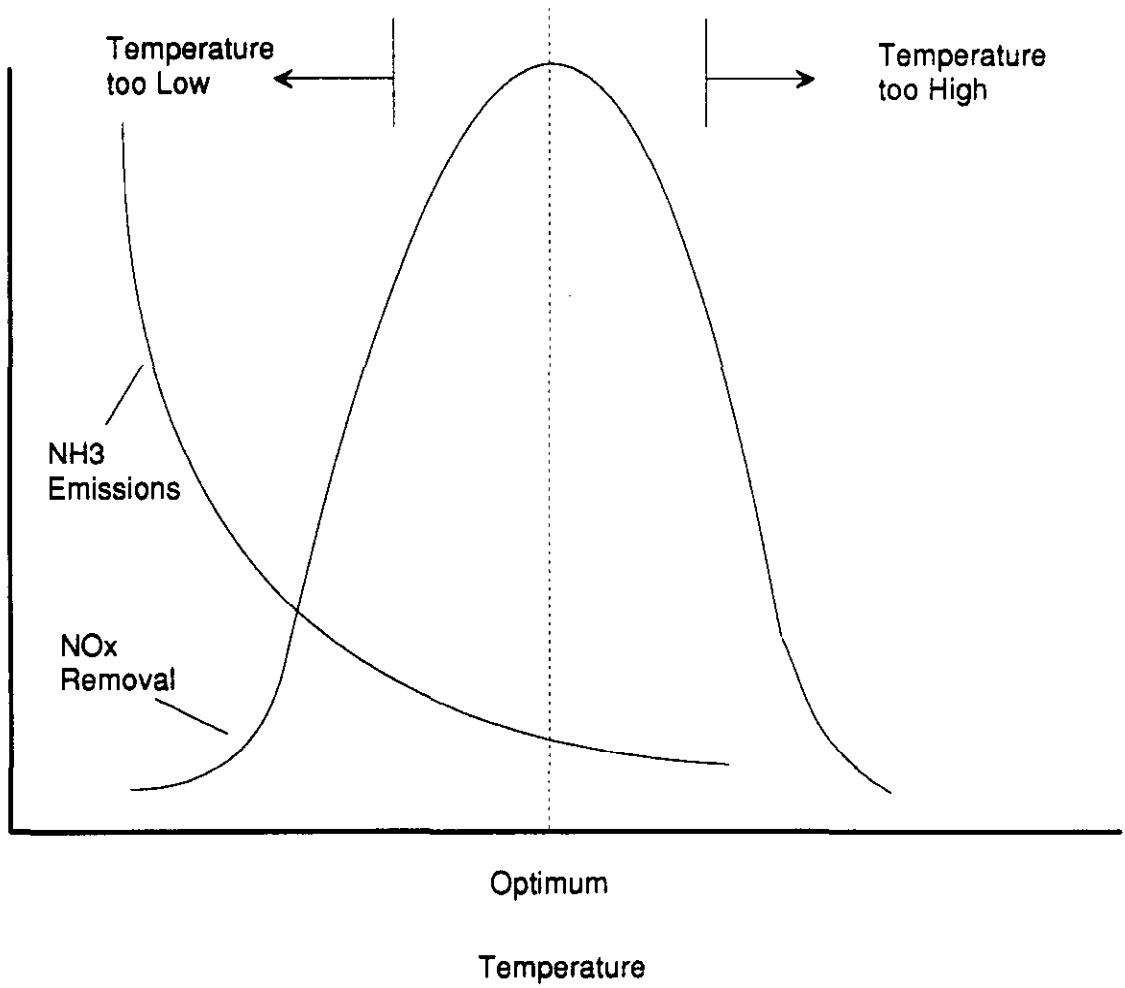
Temperature

Figure 2-1. Conceptual Temperature Window for the SNCR Process

Humidification

The effectiveness of the calcium-based reagent in reducing $SO_2$ emissions when injected downstream of the air heater can be increased by flue gas humidification. Flue gas conditioning by humidification involves injecting water into the flue gas downstream of the air heater and upstream of any particulate removal equipment. The water is injected into the duct by dual-fluid atomizers which produce a fine spray that can be directed downstream and away from the duct walls. The subsequent evaporation causes the flue gas to cool, thereby decreasing its volumetric flow rate and increasing its relative and absolute humidity. It is important that the water be injected in such a way as to prevent it from wetting the duct walls and to ensure complete evaporation before the gas enters the particulate removal equipment or contacts the duct turning vanes. Since calcium-based reagents are not as reactive as sodium-based reagents, the presence of water in the flue gas, which contains unreacted reagent, provides for additional $SO_2$ removal. Up to 50 percent $SO_2$ removal is expected when calcium-based reagents are used in conjunction with flue gas humidification.

## 2.2    PROJECT PARTICIPANTS

PSCC is the Project Manager for the project, and is responsible for all aspects of project performance. PSCC has engineered the dry sorbent injection system and the modifications to the flyash system, provided the host site, trained the operators, provided selected site construction services, start-up services and maintenance, and is assisting in the testing program.

B&W was responsible for engineering, procurement, fabrication, installation, and shop testing of the low-$NO_x$ burners, overfire air ports, humidification equipment, and associated controls. They are also assisting in the testing program, and will provide for commercialization of the technology. NOELL, Inc. was responsible for the engineering, procurement and fabrication of the SNCR system. Fossil Energy Research Corp. is conducting the testing program. Western Research Institute is characterizing the waste materials and recommending disposal options. Colorado School of Mines is conducting research in the areas of bench-scale chemical kinetics for the $NO_2$ formation reaction with dry sorbent injection. Stone & Webster Engineering is assisting PSCC with the engineering efforts. Cyprus Coal and Amax Coal are supplying the coal for the project, while Coastal Chemical, Inc. is providing the urea for the SNCR system.

## 2.3   BOILER DESCRIPTION

Arapahoe Unit 4 is the largest of four down-fired boilers located at the Arapahoe station and is rated at 100 MWe. The unit was built in the early 1950's and was designed to burn Colorado lignite or natural gas. Currently, the main fuel source for the station is a Colorado low-sulfur bituminous coal. Although the unit can be run at full load while firing natural gas, this fuel is only occasionally used to provide load when pulverizers or other equipment are out of service. An elevation view of the boiler is shown in Figure 2-2.

The furnace firing configuration is a down-fired system employing 12 intertube burners located on the roof and arranged in a single row across the width of the furnace. A single division wall separates the furnace into east and west halves, each with six burners. 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 gas passes through a horizontal duct and is then directed downward through a tubular air heater. After leaving the air heater, the flue gas passes through a reverse gas baghouse for particulate control. Induced draft fans are positioned downstream of the baghouse and deliver the flue gas into a common stack for Units 3 and 4.

The intertube burners are not comparable to a more common wall-fired burner. Each burner consists of a rectangular coal/primary air duct which is split into 20 separate nozzles arranged in a four by five rectangle that injects the coal/air mixture evenly across the furnace roof. A secondary air windbox surrounds each burner and allows air flow around each of the individual coal nozzles, resulting in a checkerboard pattern of coal/primary air and secondary air streams. The burners have no provisions to control the rate of fuel and secondary air mixing.

The burners are numbered one through twelve from west to east. Each of the four attrition mills supplies primary air and coal to three of the burners. The coal piping allows each mill to supply two burners in one furnace half and one in the other half. Figure 2-3 shows the burner firing configuration and coal distribution arrangement from the four mills. The secondary air ducts are positioned behind the burners and include a secondary air damper for each burner. When a single burner is removed from service, the secondary air flow is also stopped by closing the
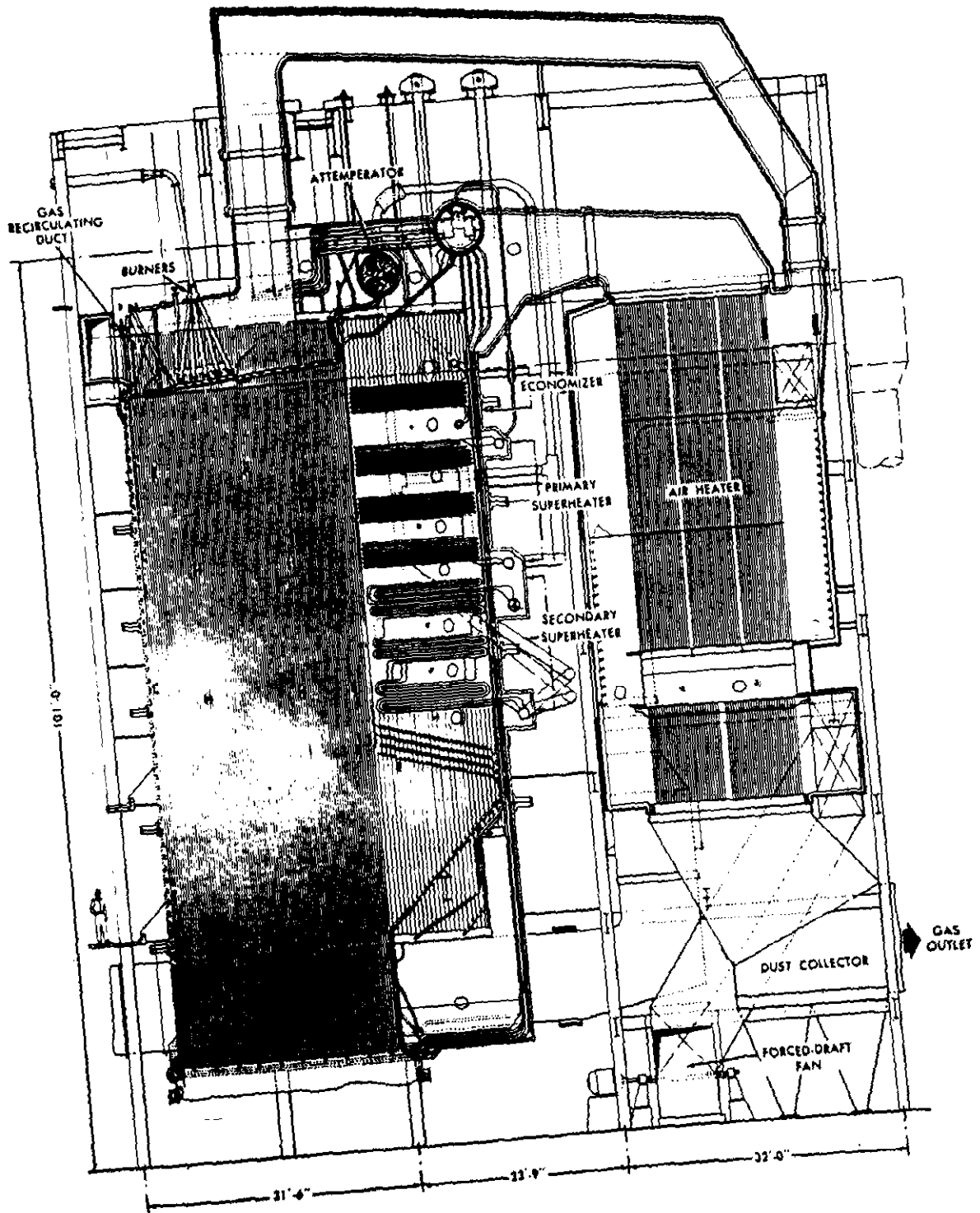
Figure 2-2. PSCC Arapahoe Unit 4

FERCo-7034-R229
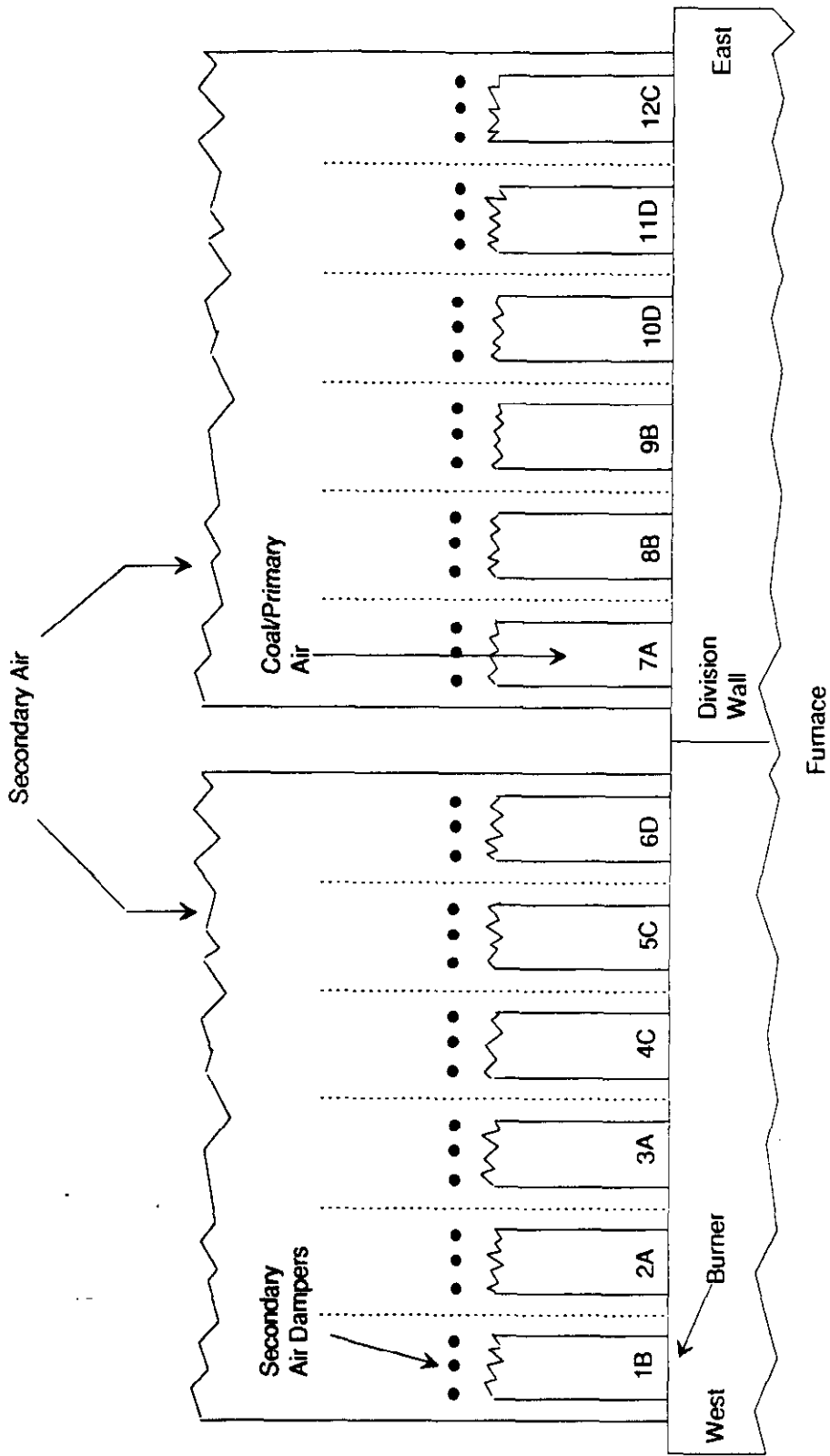
Figure 2-3. Burner-Mill Arrangement - Looking to the North
(Note: the letter next to each burner designates one of the four pulverizers)

FERCo-7034-R229

associated secondary air damper. The dampers are manually controlled at the burner deck and are intended for on/off duty only.

## 2.4    BASELINE BURNER TEST RESULTS

The baseline tests on Arapahoe Unit 4 were performed to document the initial emissions of $NO_x$ and $SO_2$, without any modifications to the boiler or burner systems. These tests were performed during the period from November 11 to December 15, 1991, and the results pertinent to the current phase of testing, namely, the effect of load and excess $O_2$ levels on the baseline $NO_x$ levels, are summarized in this section. Complete documentation of the baseline test results is contained in a separate report.[1]

The difference between NO and $NO_x$ emissions was monitored on most tests during the baseline burner tests, and the difference was found to be not significant within the limits of detection. Thus, for the purposes of this report, NO and $NO_x$ emissions are used interchangeably.

Figure 2-4 summarizes the baseline $NO_x$ data as a function of economizer exit $O_2$ for three loads (60, 80, and 100 MWe). The Arapahoe Unit 4 boiler is used nearly exclusively for load regulation by the PSCC system dispatch center (i.e., the load is rarely constant for a long period of time). Therefore, the number of mills in service at the loads tested during the baseline test series were chosen to reflect the number normally in service when regulating at that particular load: four mills at 100 and 80 MWe, and 3 mills at 60 MWe.

The data in Figure 2-4 indicate that the effect of excess air, or operating $O_2$ level, on the $NO_x$ emissions was significant. The curves for the three boiler loads have similar $NO_x$ versus $O_2$ slopes, nominally 145 ppmc (parts per million corrected to 3 percent $O_2$ concentration $O_2$ dry) $NO_x$/percent $O_2$. This represents a large effect of $O_2$ on $NO_x$ compared to other furnace designs. For full load operation, this dependence on $O_2$ resulted in the $NO_x$ emissions ranging from 760 ppmc at 3.7 percent $O_2$ to 1060 ppmc at 5.7 percent $O_2$. This $O_2$ effect was found to be the most important operational parameter affecting the baseline $NO_x$ emissions with the original combustion system.
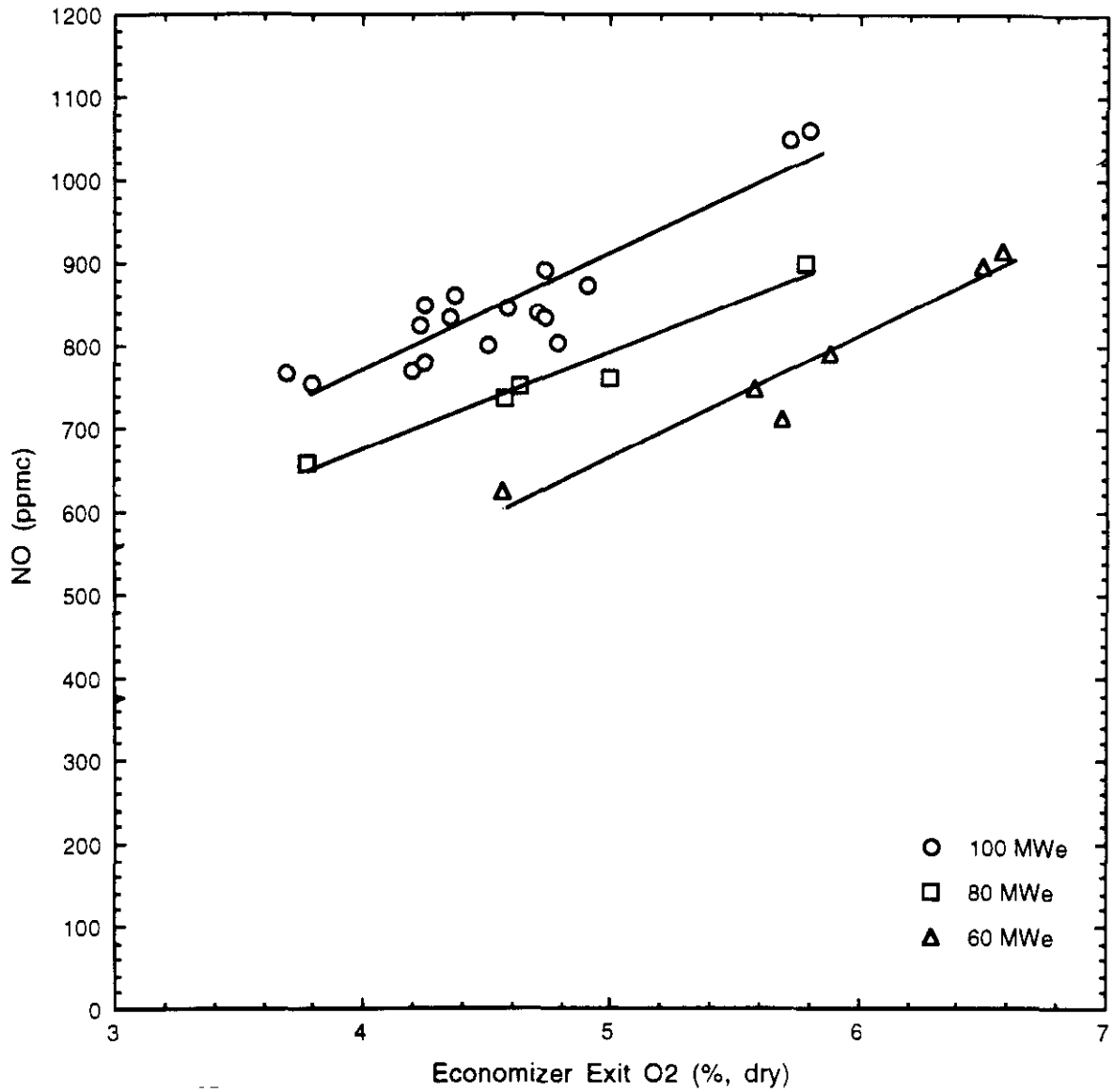
Figure 2.4. Baseline NO Emissions as a Function of Economizer Exit O$_2$

FERCo-7034-R229

The data in Figure 2-4 also indicate that for a constant economizer exit $O_2$ level, the $NO_x$ emissions decreased as the load was reduced. However, normal operation at Arapahoe Unit 4 required that $O_2$ levels be increased as the load was reduced in order to maintain steam temperatures. $NO_x$ emissions at typical base loaded operating $O_2$ levels are replotted in Figure 2-5 as a function of boiler load. The highest $NO_x$ emissions occur at 100 MWe and the levels decrease as the load is reduced. Below 80 MWe, $NO_x$ emissions decreased only slightly, due to the counteracting effects of increasing $O_2$ level and reduced heat release rate. The $O_2$ levels maintained during the typical base loaded boiler operation are also included in Figure 2-4 and show that $O_2$ levels increased with decreasing load. Since the $NO_x/O_2$ relationship of Arapahoe Unit 4 was relatively steep, higher $O_2$ levels prevented significant $NO_x$ reductions at reduced loads. At typical base loaded operating $O_2$ levels, the $NO_x$ emissions ranged from nominally 760 to 850 ppmc (1.04 to 1.16 lb/MMBtu) over the load range of 60 to 100 MWe.

## 2.5    BASELINE SNCR TESTS

The SNCR tests with the original Arapahoe Unit 4 combustion system were performed to demonstrate and document the $NO_x$ removal potential of SNCR without other modifications to the boiler or burner systems. These tests will then provide a basis on which to compare the performance of the low-$NO_x$ combustion system and the combination of the LNB/OFA and SNCR systems.

This initial baseline SNCR test series was brief in scope in order to accommodate the Arapahoe Unit 4 retrofit schedule. Because of the brevity of the program, which was conducted over the 5-week period from February 4, 1992, to March 6, 1992, no extensive optimization of the SNCR system with the original combustion system was possible. The test program consisted of 1) start up of the SNCR system, and 2) a limited parametric test series on the performance of urea and aqueous ammonia as SNCR chemicals.
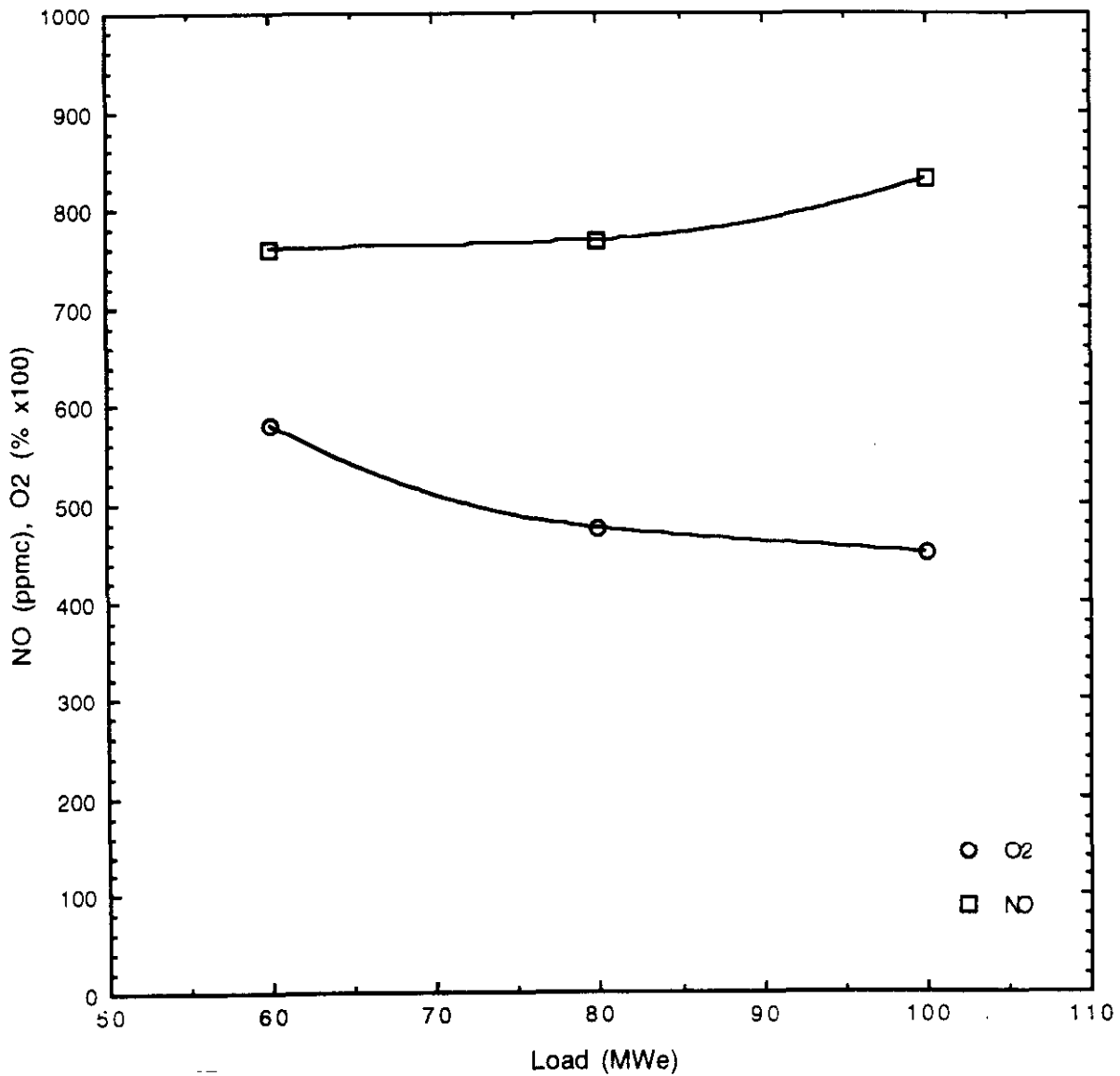
Figure 2-5.  Baseline NO and $O_2$ Levels as a Function of Boiler Load
with Typical Base Loaded Boiler Operation

FERCo-7034-R229

# 3.0 MEASUREMENT METHODS

The SNCR test activities with the baseline burner system required documentation of gaseous emissions, as well as boiler operational performance parameters. This section summarizes the measurement methods that were used during the initial SNCR phase of the test program with the original burners.

## 3.1    GAS ANALYSIS INSTRUMENTATION

The gas analysis monitors and sample conditioning system were installed in a mobile gas analysis laboratory, which was located on the west side of the boiler. The continuous gas analysis instruments included:

- Teledyne Model 326 electrochemical $O_2$

- ThermoElectron Model 10 chemiluminescent $NO/NO_x$

- Horiba Model 2000 NDIR CO

- Horiba Model 2000 NDIR $CO_2$

- Western Research Model 721A NDUV $SO_2$

- Siemens Model 5E NDIR $N_2O$

- Perkin Elmer MCS100, $NH_3$ (described separately in Section 3.2)

The measurement of $O_2$ and $CO_2$ were made in accordance with EPA Method 3a. CO measurements were made in accordance with EPA Method 10, except that instrument $CO_2$ interferences were accounted for by utilizing a triblend span gas of $O_2$, CO and $CO_2$ in $N_2$. The span gas $CO_2$ value was chosen to be near the expected $CO_2$ level in the flue gas, thus the $CO_2$ interference was accounted for during calibration of the CO instrument.

EPA Methods 7e and 6c specify procedures for the continuous measurement of $NO_x$ and $SO_2$, respectively. Both of these methods require sample transport lines heated sufficiently (250°F) to maintain the sample gas above the dew point. Since 20 separate sample lines were utilized during the current test program, it was not economically feasible to utilize heated lines for each.

A single heated sample line was utilized to make $NO_x$ and $SO_2$ measurements in accordance to the EPA methods. These measurements showed that the length of the sample lines were short enough, and sampling rates high enough, such that there was no measurable loss of either $NO_2$ or $SO_2$ in the unheated sample lines.

A simplified schematic of the sample conditioning and gas analysis system is shown in Figure 3-1. The system can accommodate up to 48 individual sample lines. Up to 12 of these can be composited together and then analyzed. Each of the individual sample streams is dried in a refrigerated dryer where the gas is cooled and the moisture dropped out in a trap. Each stream then passes through a metering valve and rotameter, after which all the streams are blended together in a manifold and directed to a pair of sample pumps. The rotameters are used to balance the individual flows in order to provide an accurate composite blend. Two high-volume sample pumps are utilized to provide a sample flowrate sufficient to avoid scrubbing of $NO_2$ and $SO_2$ in the unheated sample lines upstream of the refrigerated dryer. This flowrate is well in excess of that required by the instruments. Downstream of the pumps, a portion of the composited sample is diverted to a final pass through the condenser (where the increased pressure aids in the removal of any remaining moisture), through a final particulate filter, and then to the instruments for analysis. Metering valves and rotameters are used to assure the required sample flow to each instrument.

The location of the 19 unheated sample probes during the current phase of testing was identical to that for the baseline burner tests, namely: 12 at the exit of the economizer, 6 at the exit of the air preheater, and one in the fabric filter outlet duct leading to the stack. The sample probe grid in the horizontal duct at the economizer exit is shown in Figure 3-2. Although this duct is 40 feet wide, it is only 7 feet deep, so an array of probes positioned two high by six wide was deemed adequate to obtain a representative gas sample. The short probes were located at one-fourth of the duct depth and the longer probes at three-fourths of the duct depth. This spacing vertically divided the duct into equal areas. The use of two probe depths also provided the opportunity to ascertain any vertical stratification of gas species within the duct. Individual sample probes consisted of stainless steel tubing with sintered metal filters on the ends. The sample lines which transported the gas to the sample conditioning system consisted of polyethylene tubing which was heat traced and insulated to prevent freezing during the winter months.
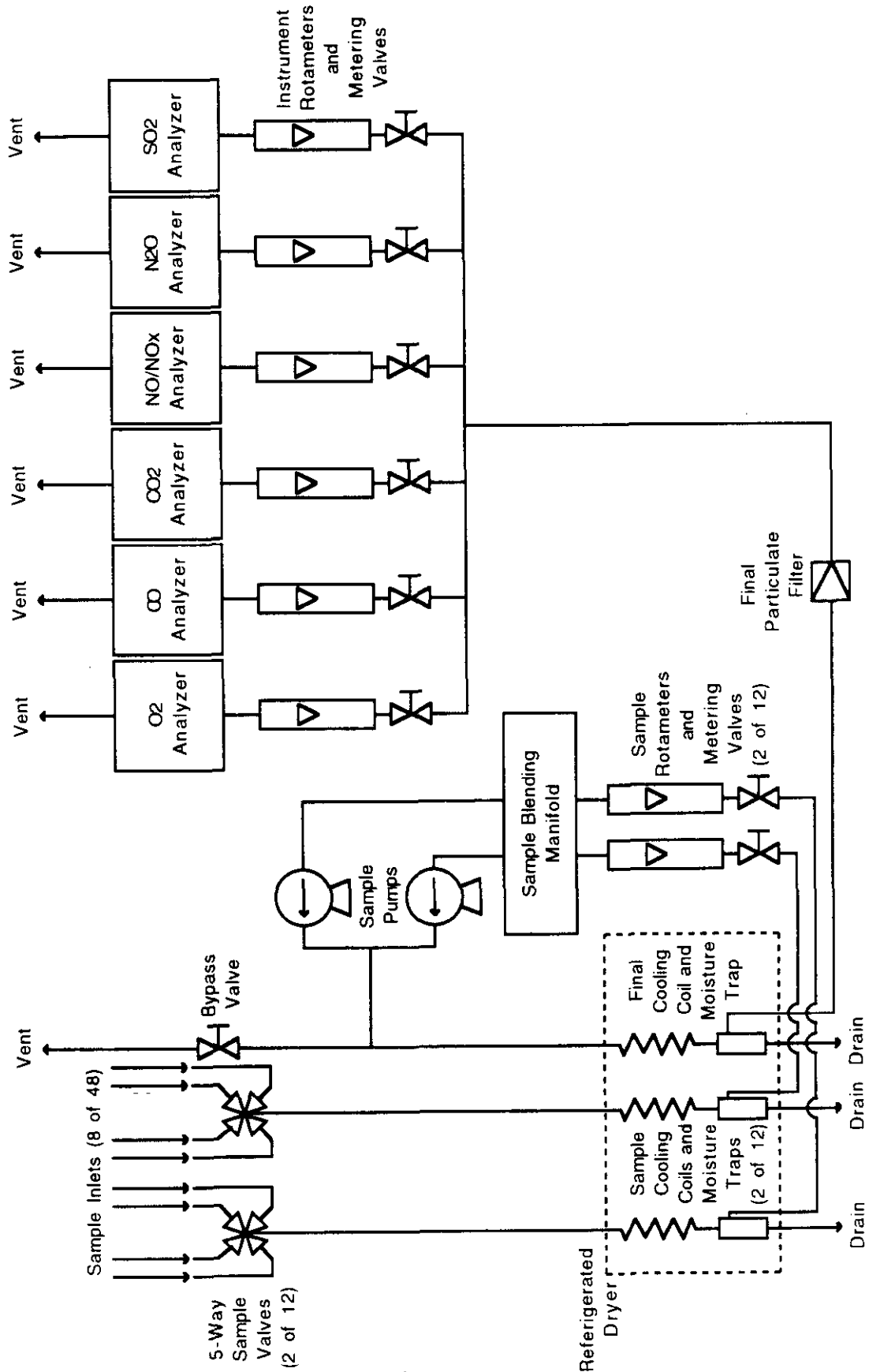
Figure 3-1. Simplified Schematic of Sample Conditioning and Gas Analysis System

FERCo-7034-R229
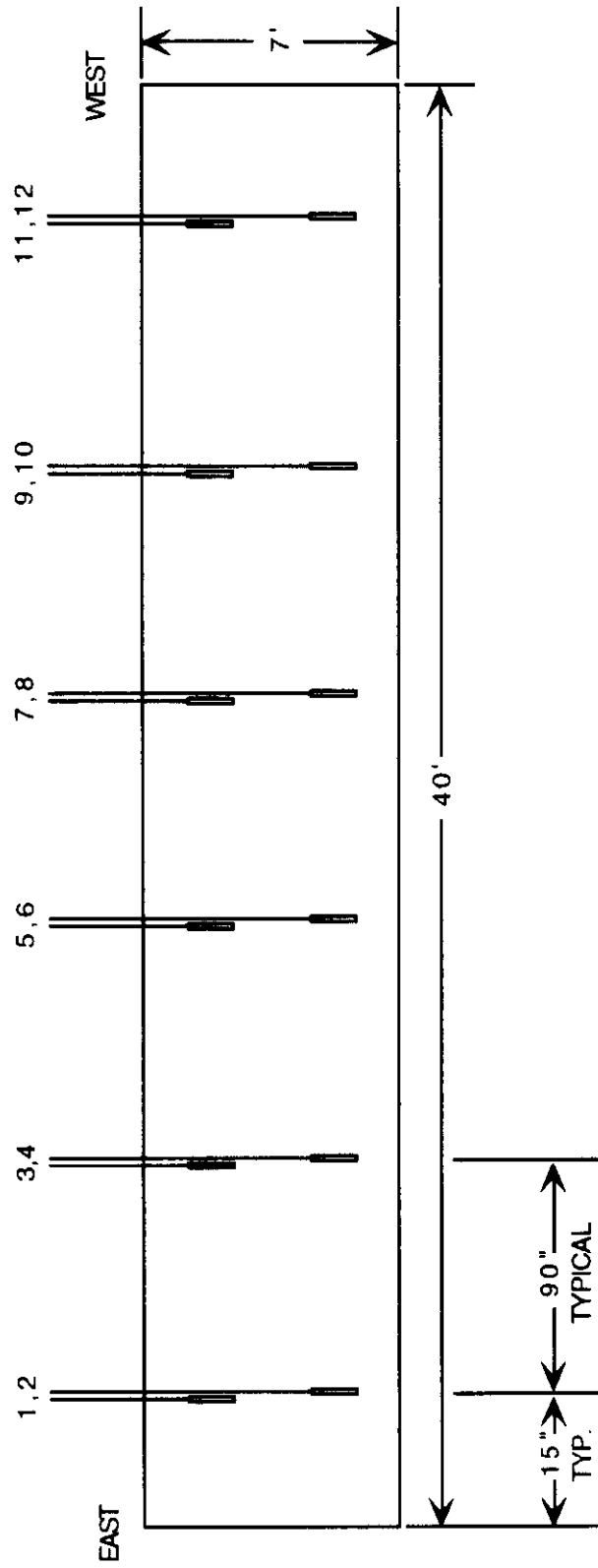
Figure 3-2. Economizer Exit Sampling Locations

FERCo-7034-R229

Additional gas sampling probes were installed at the air heater exit and stack (fabric filter outlet duct) locations. Whereas the 12-point economizer exit sampling grid would be utilized for detailed point-by-point measurements, the air heater exit and stack sampling probes would be used only to obtain general duct averages at these locations. Therefore, only a limited number of probes were utilized at these test locations; seven (six unheated and one heated) at the air heater exit and a single unheated probe at the stack location. Figure 3-3 shows the location of the probes at the air heater exit. Six of these probes utilized sample tubing which was similar to that installed at the economizer exit (i.e., "cold" lines that were insulated and heat traced to provide freeze protection). These staggered probes were installed at one-fourth and three-fourths duct depths, similar to the economizer exit. The seventh probe was located at one-half duct depth and utilized a heated line (controlled to 250°F) to transport the gas sample to the mobile laboratory. This sample point was utilized to check the representativeness of the $NO_2$ and $SO_2$ values measured through the unheated lines.

Since the "stack" sampling location was located in the duct downstream of the fabric filter and induced draft fans where little stratification of the flue gas stream exists, only a single probe was utilized at this location. Figure 3-4 shows the installation of this probe. The sampling line was insulated and heat traced for freeze protection.

The instruments utilized during the baseline urea test program were housed in a mobile gas analysis laboratory. The system was manually operated to permit calibration or sampling at the various sample points as required. The system was housed in a heated and air conditioned environment to permit stable instrument temperature and, therefore, minimal instrument calibration drift.

Instrument calibration could be performed on demand and was performed prior to every test. In cases where a single test extended longer than one or two hours, more frequent calibrations were performed. For the baseline SNCR tests, analyzer calibrations were performed at least every two hours during a long test. Frequent calibration would allow the detection and elimination of instrument drift problems. Cross checks were also performed to confirm that new calibration gas cylinders were in agreement with older cylinders in use.
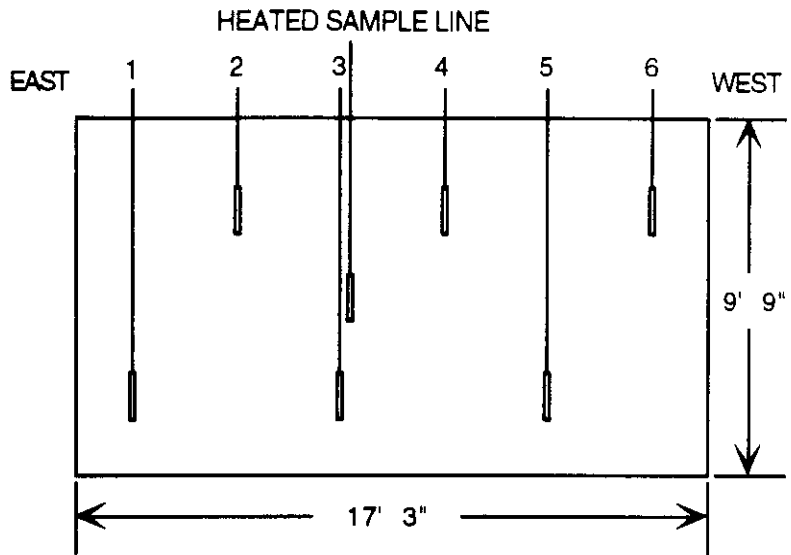
Figure 3-3.  Air Heater Exit Sampling Locations
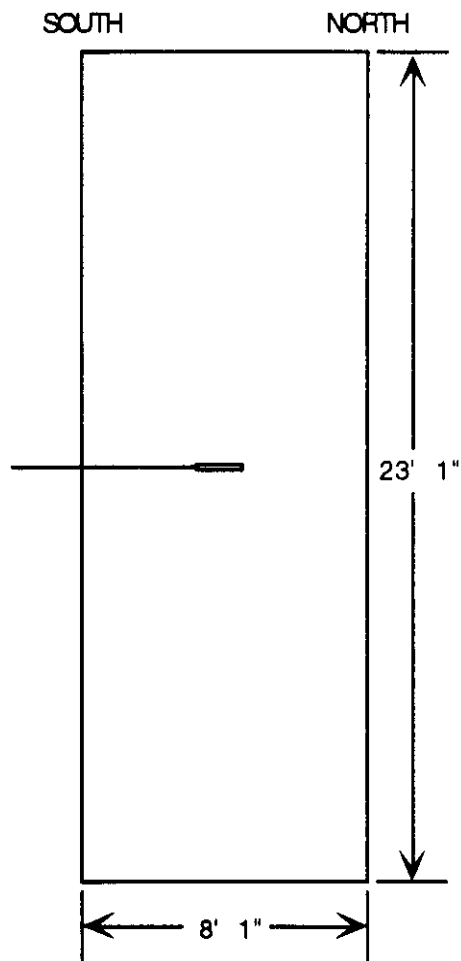


Figure 3-4.  Fabric Filter Outlet Duct Sampling Location

During the baseline burner tests, TRC Environmental Consultants was contracted to perform a Relative Accuracy Test Audit (RATA) to verify the accuracy of the combustion gas analysis system. These tests consisted of a cylinder gas audit (CGA), utilizing ±1 percent accurate calibration gases and were performed for $O_2$, $NO_x$, $SO_2$, and CO. The calibration gases used were certified to be analyzed following the EPA traceability Protocol Number 1.

The results indicated that the difference between the reference gas and the FERCo instrument response was within the ±15 percent limits of the CGA test methodology (40 CFR, Part 60, Appendix F). The $O_2$, $NO_x$, $SO_2$ and CO emissions showed good relative accuracy during these verification tests with relative errors of 0.2, -4.0, 0.6 and -8.7 percent, respectively.

## 3.2    $NH_3$ MEASUREMENTS

The measurement of $NH_3$ emissions is an important aspect of quantifying the performance of a SNCR system. Traditionally, batch or wet chemical sampling techniques have been used for this purpose. However, the time delay between the collection of the sample and the delivery of the results, due to the required laboratory analysis, is less than optimal when trying to optimize process performance in a field test situation. Recently, a number of continuous ammonia analyzers have become available, which could provide the on-line performance desirable for a field test program. However, these analyzers are considered to be in a developmental and proving stage, due to difficulties in obtaining and preserving valid gas samples, especially in sulfur-laden environments.

Wet chemical $NH_3$ analysis was the primary measurement used during the current test program. Although an EPA method is not available for $NH_3$ measurement, the method described below has been utilized by Fossil Energy Research Corp. and others during numerous test programs and has been proven sufficiently accurate. This $NH_3$ measurement technique involves scrubbing nominally two cubic feet of flue gas through an impinger train containing 0.02N sulfuric acid. The probe and teflon line between the probe and impingers are then washed with dilute sulfuric acid and included with the impinger solutions. The impinger solutions are then analyzed for ammonia using a specific ion electrode. The majority of the wet chemical ammonia samples were obtained from a set of six ports located in the air heater exit duct (just upstream of the ports used for the continuous gas analysis samples shown in Figure 3-3). A more limited number of samples were

obtained downstream of the fabric filter. Unless noted otherwise, the ammonia values presented in the results section are composite samples obtained from the duct at the air heater exit.

As mentioned above, a continuous $NH_3$ analyzer would markedly facilitate SNCR system optimization and testing. During the current phase of testing, a continuous $NH_3$ analyzer was also utilized, with the goal of this effort being to assess the severity of the problems to be encountered in making this measurement in the sulfur-containing flue gas. The continuous $NH_3$ analyzer was a Perkin Elmer model MCS100 provided to the program by NOELL, Inc. The MCS100 is an infrared-based multigas analyzer.

The specific analyzer configuration used during these tests measures $NH_3$, $H_2O$ and $CO_2$. Interferences by $H_2O$ and $CO_2$ are then accounted for electronically. The entire sample stream (probe, sample line, pump, flow meter, and measuring cell) is maintained at 250°C (482°F) to preserve the integrity of the sample. The analyzer is mounted in a stand-alone cabinet, separate from the rest of the continuous gas analysis instrumentation, and was located adjacent to the gas sampling location at the air heater exit. Due to the heat tracing requirements, only a single point sample was used. As mentioned previously, the $NH_3$ measurements reported in the results section are primarily from the wet chemical technique, and any measurements taken from the continuous analyzer are so designated. Due to of the single point sampling configuration of the continuous analyzer, the representativeness of the $NH_3$ measurement was questionable. In addition, during the first two weeks of SNCR testing, the probe could not be heat traced due to the port configuration, which impaired the performance of the continuous $NH_3$ continuous analyzer.

## 3.3    FLUE GAS TEMPERATURE MEASUREMENTS

During the course of the baseline SNCR test program, flue gas temperature measurements were made on a regular basis. The data were gathered at the entrance to the SNCR chemical injection zone (Port G in Figure 3-5), using an acoustic pyrometer.

In order to verify the acoustic data, High Velocity Thermocouple (HVT) measurements were made at selected operating conditions through Port G on the west side of the boiler (structural steel and a stairway precluded HVT access to the east port). The HVT probe utilized for these
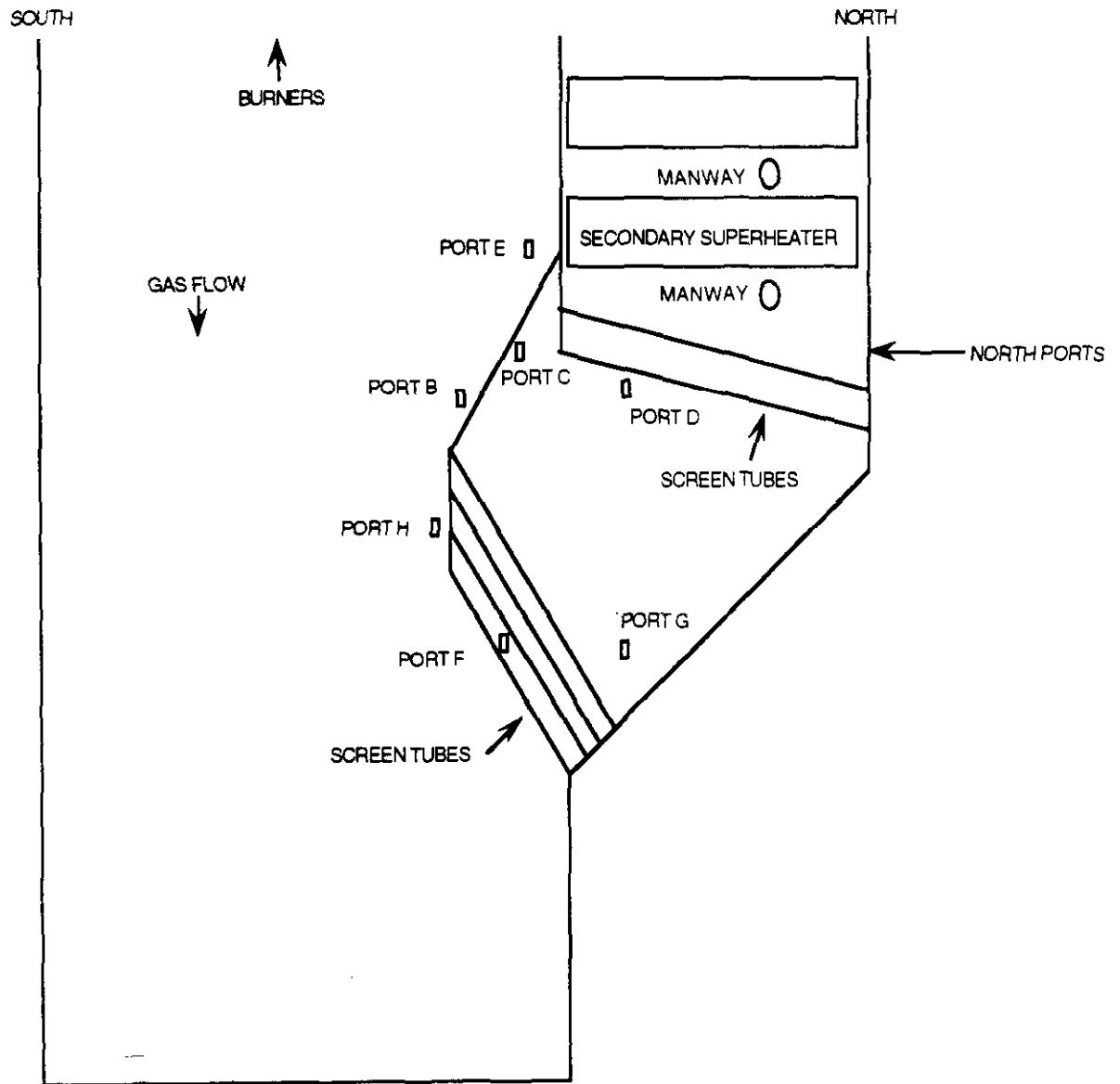
Figure 3-5. Temperature Sample Port Locations

FERCo-7034-R229

measurements was of a standard water-cooled design, utilizing a single radiation shield and a type R thermocouple.

# 4.0 SNCR SYSTEM

## 4.1    PROCESS DESCRIPTION

Selective Non-Catalytic Reduction (SNCR) is a class of $NO_x$ control processes developed to reduce $NO_x$ emissions from fossil fuel combustion systems. SNCR processes involve the injection of a nitrogen containing chemical into the combustion products where the temperature is in the range of 1600 to 2100°F. In this range, the chemical reacts selectively with NO in the presence of oxygen, forming primarily $N_2$ and $H_2O$. SNCR chemicals each have their own optimum temperature and range within which $NO_x$ reductions can occur. At the upper end of the range, the injected chemical will react directly with $O_2$ forming additional $NO_x$. At too low a temperature, the injected chemical does not react with NO, resulting in excessive emissions of $NH_3$.

Pilot-scale testing results[2,3] have shown the optimum temperature for $NO_x$ removal with ammonia to be nominally 1750°F. With urea, the optimum temperature is nominally 100°F higher[2,3]. It is not certain whether this difference in optimum temperature is due primarily to differences in the decomposition of the chemicals and the "release" of reactive nitrogen compounds or to basic differences in the chemical reaction paths. The difference in optimum temperature ranges for $NO_x$ reduction with urea and ammonia is shown conceptually in Figure 4-1.

Two chemicals were tested during the SNCR baseline test series: ammonium hydroxide ($NH_4OH$) also referred to as aqueous ammonia and urea ($NH_2CONH_2$). Aqueous ammonia is vaporized directly to $NH_3$ and $H_2O$ when injected into the hot combustion products (Figure 4-2). This release of $NH_3$ from the aqueous to gas phase occurs from the time the drop is injected until it is completely evaporated. In the gas phase, the $NH_3$ decomposes to amidogen ($NH_2$), and then the $NH_2$ reacts with NO to form $N_2$ and $H_2O$ as shown in Figure 4-3.

The situation is somewhat different for a urea solution. The urea will tend to remain in the aqueous phase until sufficient water has evaporated from the injected drop such that the urea is near saturation. At this point, the urea will decompose with the decomposition products thought to be $NH_3$ and cyanic acid (HNCO) as shown in Figure 4-3. The $NH_3$ proceeds to react to reduce NO along the same path as for $NH_4OH$ injection. The HNCO can either react to reduce NO by
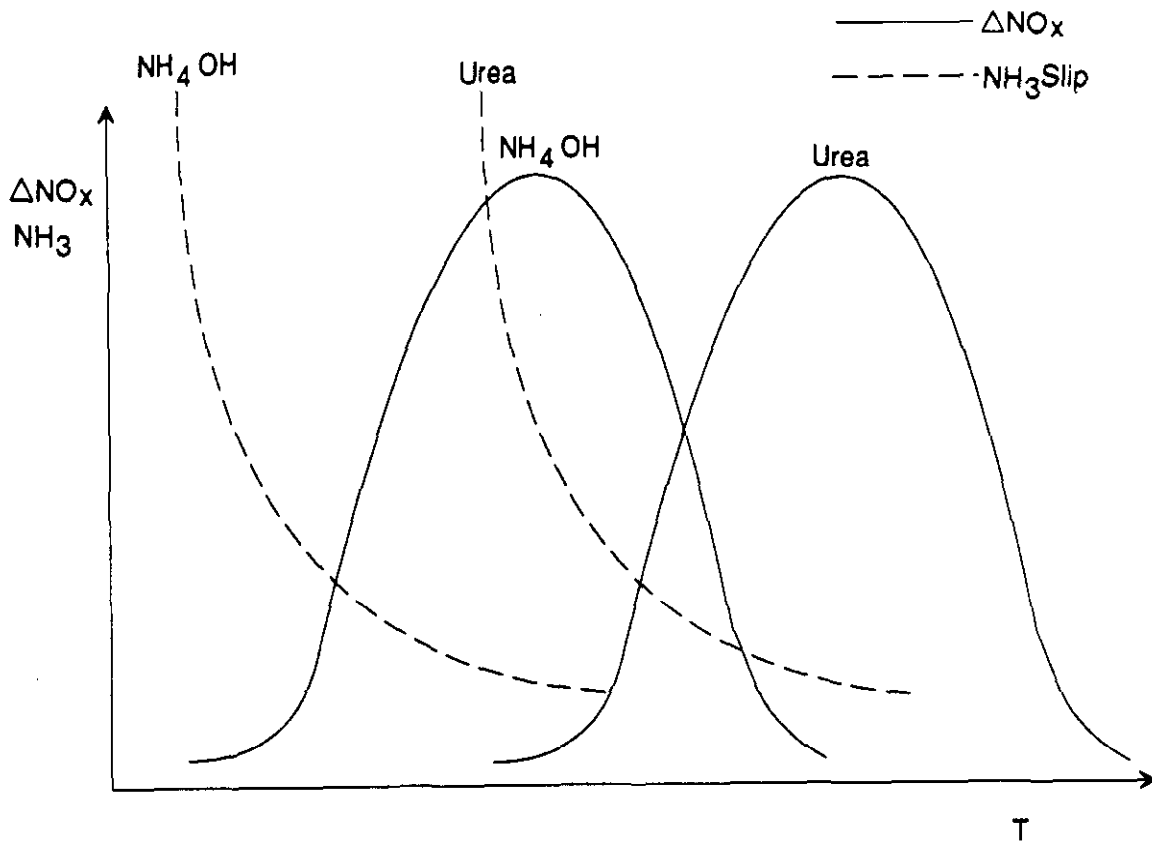
Figure 4-1. SNCR Chemical Temperature Window
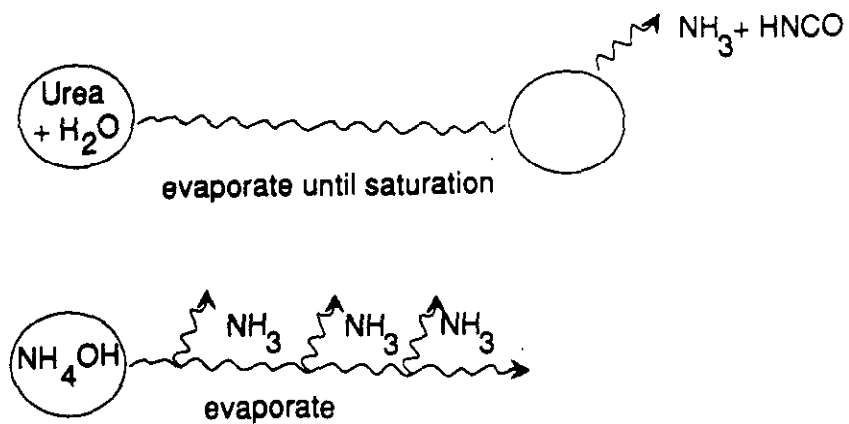


Figure 4-2. SNCR Chemical Vaporization Processes

FERCo-7034-R229
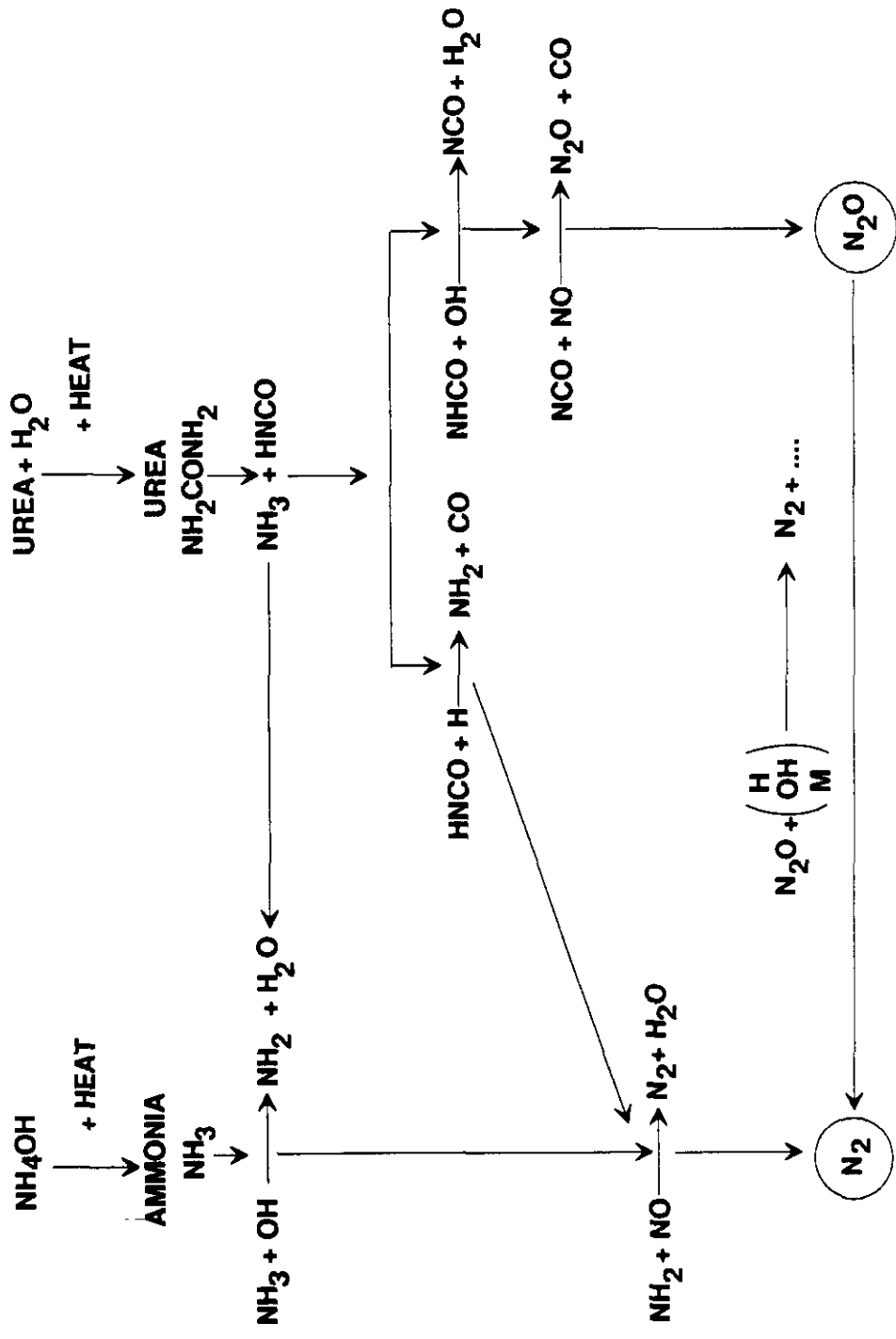
Figure 4-3. Major SNCR Chemical Paths for Urea and Ammonia

FERCo-7034-R229

combining with H, or it can go through a path which will produce nitrous oxide ($N_2O$) by reacting with a hydroxyl radical (OH). Depending on the temperature and residence time, the $N_2O$ will either decompose further to $N_2$ through reactions with H, OH or one of a number of other molecules (M), or be emitted as a by-product of the SNCR process.

## 4.2    SYSTEM DESIGN

Before the detailed design of a SNCR system can be completed, the basic temperature distribution and velocity flow patterns within the boiler must be defined. The temperature and velocity fields were characterized through two separate efforts:

1)    on-site flue gas temperature measurements using acoustic pyrometry and HVT measurements, and

2)    laboratory cold flow testing using a 1:10 scale model of the Arapahoe Unit 4 boiler.

These two efforts are described below in more detail.

### 4.2.1  Flue Gas Temperature Measurements

Detailed gas temperature measurements were performed at Arapahoe Unit 4 with the original combustion system during the period of April 15 to 19, 1991. This was seven months before the beginning of the baseline burner tests, and approximately ten months before the start of the baseline SNCR tests. The measurements were made in order to locate the temperature regions where urea injection was believed to be most effective (1650 to 1950°F). While it was expected that the combustion modifications would alter the temperature distribution within the boiler, it was believed that change would be minimal (on the order of only 25°F). Acoustic and suction pyrometry techniques were used simultaneously to obtain the gas temperature measurements. The results of these measurements are briefly summarized below, and complete documentation of the temperature measurement tests is contained in a separate report[4].

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 pyrometer sends a sound pulse across the furnace; the transit time for the pulse is measured and thus, the mean speed of sound across the furnace is determined. The average temperature along the path can then be determined from the speed of the sound pulse. The acoustic

temperature measurement technique requires a clear line of sight across the furnace at the measurement location. Since the Arapahoe Unit 4 boiler has a division wall running the length of the furnace, the first available location with acceptable access for the acoustic instrument was through a pair of ports just downstream of the first set of screen tubes (Location G in Figure 4-4).

Temperature measurements were made at the six boiler operating conditions listed in Table 4-1. These loads were selected as they represent a range of normal operating conditions for Arapahoe Unit 4. The unit generally runs with four mills in service at loads above 80 MWe, although 100 MWe can be maintained with only three mills. The unit often operates at or near 50 MWe with only two mills in service at night when the demand for load is low.

Table 4-1

BOILER OPERATING CONDITIONS FOR FLUE GAS TEMPERATURE MEASUREMENTS
(April 15 to 19, 1991)

| Load (MWe) | Mills out of Service* |
|:---:|:---:|
| 100 | None |
| 100 | B |
| 80 | None |
| 80 | B |
| 60 | B |
| 50 | B,C |

*Four mills total, designated A, B, C and D (see Figure 2-3 for a diagram of the burners supplied by each mill)

The temperature measurements were made upstream of the convective section. The locations of the sample ports are shown in an elevation view of the furnace (looking from the east) in Figure 4-4. Port H was situated at the furnace exit upstream of the lower set of screen tubes. Port F was located between the first and second rows of tubes, and Port G was near the back wall downstream of the first screen tube set. Port D was located upstream of the second set of screen tubes, and the manway door upstream of the secondary super heater (which had been previously modified with a 2-inch diameter port) provided access to the region downstream of the second screen tube set. This area could also be probed through a series of eight ports along the north (back) wall of the unit.

SOUTH                                                    NORTH

↑
BURNERS

┌─────────────────────────┐
│                         │
└─────────────────────────┘

MANWAY  ○

GAS FLOW                    ┌─────────────────────────┐
                           │  SECONDARY SUPERHEATER   │
PORT E  ▯                  └─────────────────────────┘
↓
                            MANWAY  ○

                                                    ← ─── NORTH PORTS
                    ▯
PORT B    PORT C
        ▯         ▯
          ▯    PORT D

                            SCREEN TUBES

PORT H  ▯

                    PORT G
PORT F   ▯          ▯

SCREEN TUBES
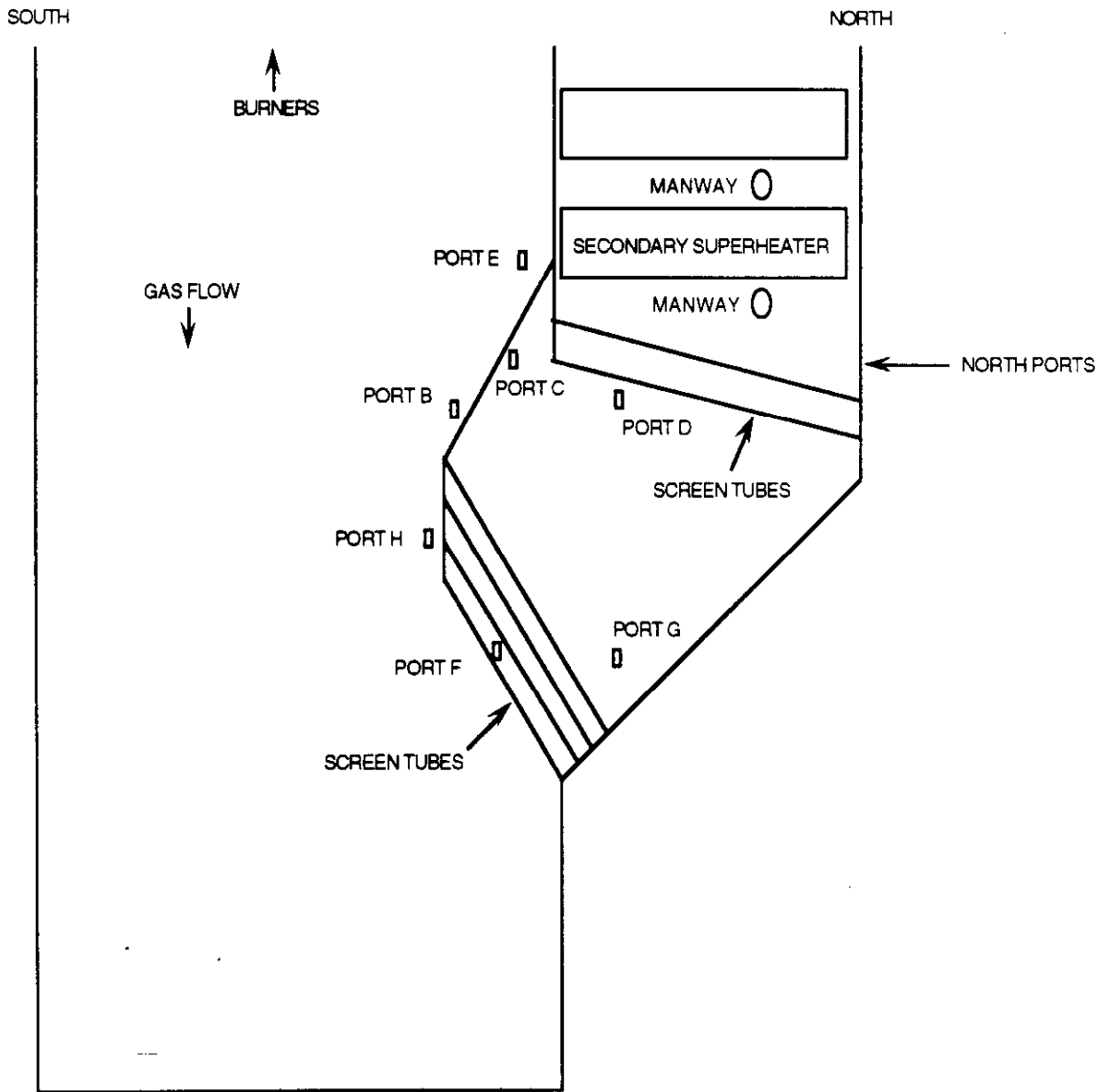
Figure 4-4. Port Locations for Temperature Measurements
(view looking from East to West)

The layout of the north ports, as well as a map detailing the burner/mill arrangement, is shown in Figure 4-5.

For each boiler operating condition (Table 4-1), acoustic pyrometry measurements were taken at the lower manway door, and at Ports G and D. Acoustic measurements were not possible at Ports H and F due to the furnace division wall. HVT measurements were made through the ports along the north wall and at Ports H and F on the west side of the unit. HVT measurements were also frequently taken at Ports D and G (west side) to provide a basis of comparison for the acoustic measurements. The 2-inch diameter ports on the manway doors were too small for the HVT probe, so the acoustic measurements made at this location were compared to the HVT data taken through the north ports.

Results. The results of the HVT and acoustic temperature tests at the six boiler operating conditions listed in Table 4-1 are summarized in Table 4-2. The table shows the average HVT value for each location which is computed from the mean values recorded at each traverse point. The high and low temperatures recorded during each HVT traverse are also indicated, and the average of the acoustic measurements are shown for each of the three locations where measurements were possible.

Although the table shows that the temperature at each position is a function of load, it also shows an overall temperature distribution which is similar for each load condition. The average temperatures as a function of load are plotted in Figure 4-6 for selected port locations. From this distribution, a generalization regarding the flow field may be inferred. Namely, the upward turn from the furnace exit through the first set of screen tubes forces most of the gas along the back (north) wall of the unit as it enters the convective section. The relatively cool temperatures measured at Port D are likely the result of a recirculation zone which is set up as the gases flow around the wall separating the furnace and convective sides of the unit. In fact, one-tenth scale flow visualization studies (discussed later in this section) confirm the existence of a recirculation zone at this location.
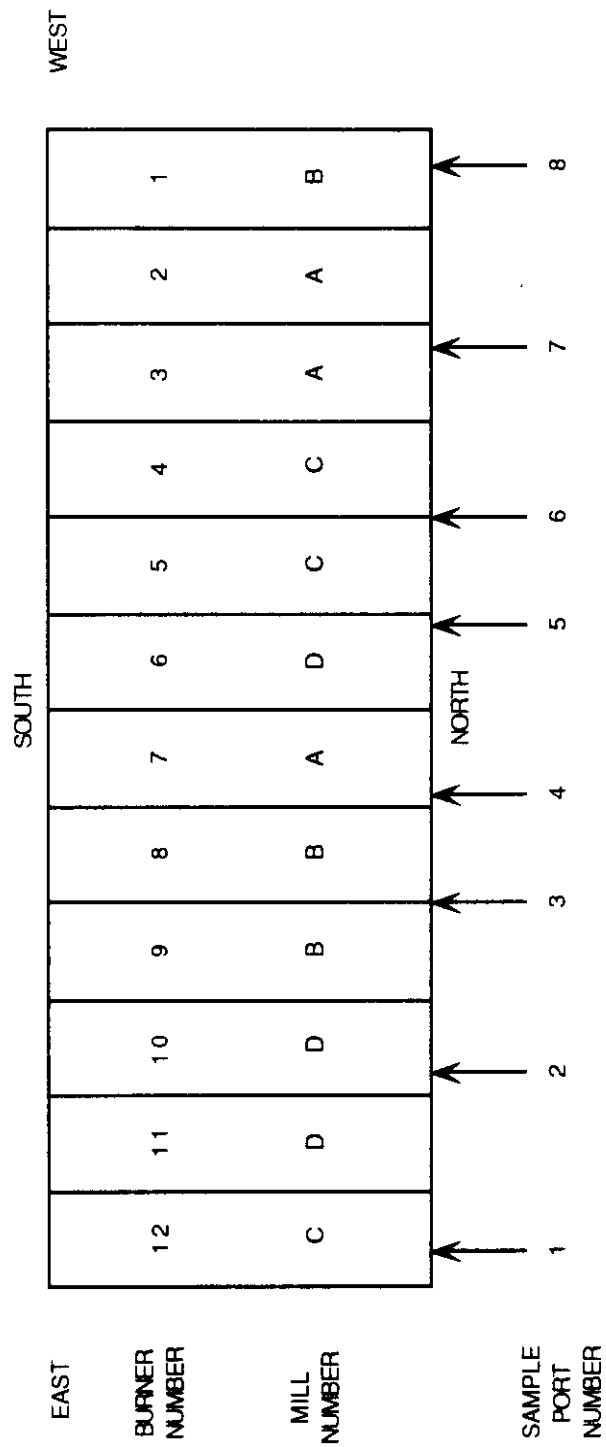
Figure 4-5. Orientation of North Ports

FERCo-7034-R229
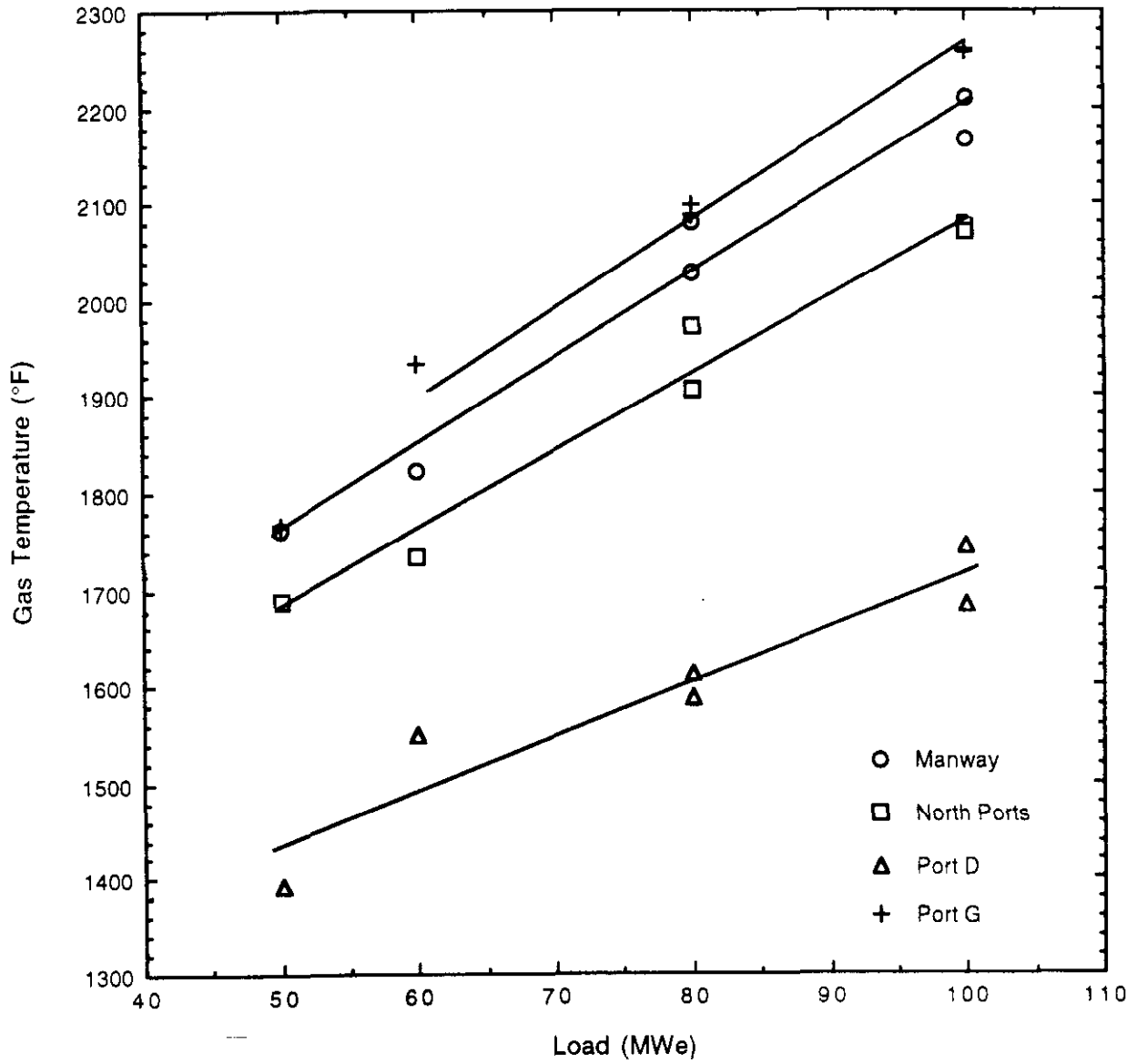
Figure 4-6. Effect of Load on Temperature at Selected Locations in the Furnace
for Temperature Measurements Performed April 15 to 19, 1991
(See Figure 4-5 for Port Locations)

FERCo-7034-R229

Table 4-2

## FLUE GAS TEMPERATURE MEASUREMENT RESULTS
### (April 15 to 19, 1991)

| Boiler Operating Condition | Measurement Type | Port H (West Side) | Port F (West Side) | Port G (West Side) | Port D (West Side) | North Ports (Manway) |
|---|---|---|---|---|---|---|
| 100 MWe, All Mills | HVT Avg. (F) | 2451 | 2346 | None | 1750 | 2079 |
| | HVT Range (F) | 2380-2535 | 2290-2425 | None | 1570-1871 | 1817-2231 |
| | Acoustic (F)* | None | None | 2256 | 1744 | 2167 |
| 100 MWe, B Mill OOS | HVT Avg. (F) | 2568 | 2346 | 2280 | None | 2069 |
| | HVT Range (F) | 2505-2630 | 2220-2490 | 2185-2320 | None | 1817-2245 |
| | Acoustic (F)* | None | None | 2302 | 1685 | 2209 |
| 80 MWe, All Mills | HVT Avg. (F) | 2401 | 2239 | None | 1618 | 1905 |
| | HVT Range (F) | 2350-2430 | 2100-2300 | None | 1462-1754 | 1655-2083 |
| | Acoustic (F)* | None | None | 2087 | 1588 | 2028 |
| 80 MWe, B Mill OOS | HVT Avg. (F) | 2263 | 2000 | None | None | 1971 |
| | HVT Range (F) | 2250-2270 | 1943-2040 | None | None | 1756-2175 |
| | Acoustic (F)* | None | None | 2097 | 1612 | 2081 |
| 60 MWe, B Mill OOS | HVT Avg. (F) | 2288 | 1982 | 1720 | 1513 | 1735 |
| | HVT Range (F) | 2190-2360 | 1833-2095 | 1669-1728 | 1416-1612 | 1551-1945 |
| | Acoustic (F)* | None | None | 1934 | 1549 | 1822 |
| 50 MWe, B and C Mills OOS | HVG Avg. (F) | 1908 | 1630 | 1487 | 1447 | 1690 |
| | HVT Range (F) | 1900-1930 | 1545-1705 | 1430-1533 | 1326-1531 | 1513-1810 |
| | Acoustic (F)* | None | None | 1767 | 1393 | 1762 |

*Acoustic measurements are a line-of-site average across the boiler.

The data discussed above are average data obtained at each of the port locations. The performance of the SNCR system can also be impacted by spatial temperature variations that might occur at each of the measuring planes. This can be the result of a number of factors, including the division wall in the furnace or the number of mills in service. The extent of this variation is shown in Figure 4-7, which shows the temperature measurements along the North wall ports at a load of 100 MWe with all four mills in service. As can be seen, the temperature variations along the east-west direction can be in excess of 300°F. Lower temperature regions were measured near the outer walls of the furnace and near the center of the furnace, downstream of the furnace division wall.

Table 4-2 also indicates that, in the areas probed, the most promising location for urea injection is the area downstream of the second set of screen tubes (near the north ports), where the average HVT temperatures range from 1690 to 2080°F over the load range.
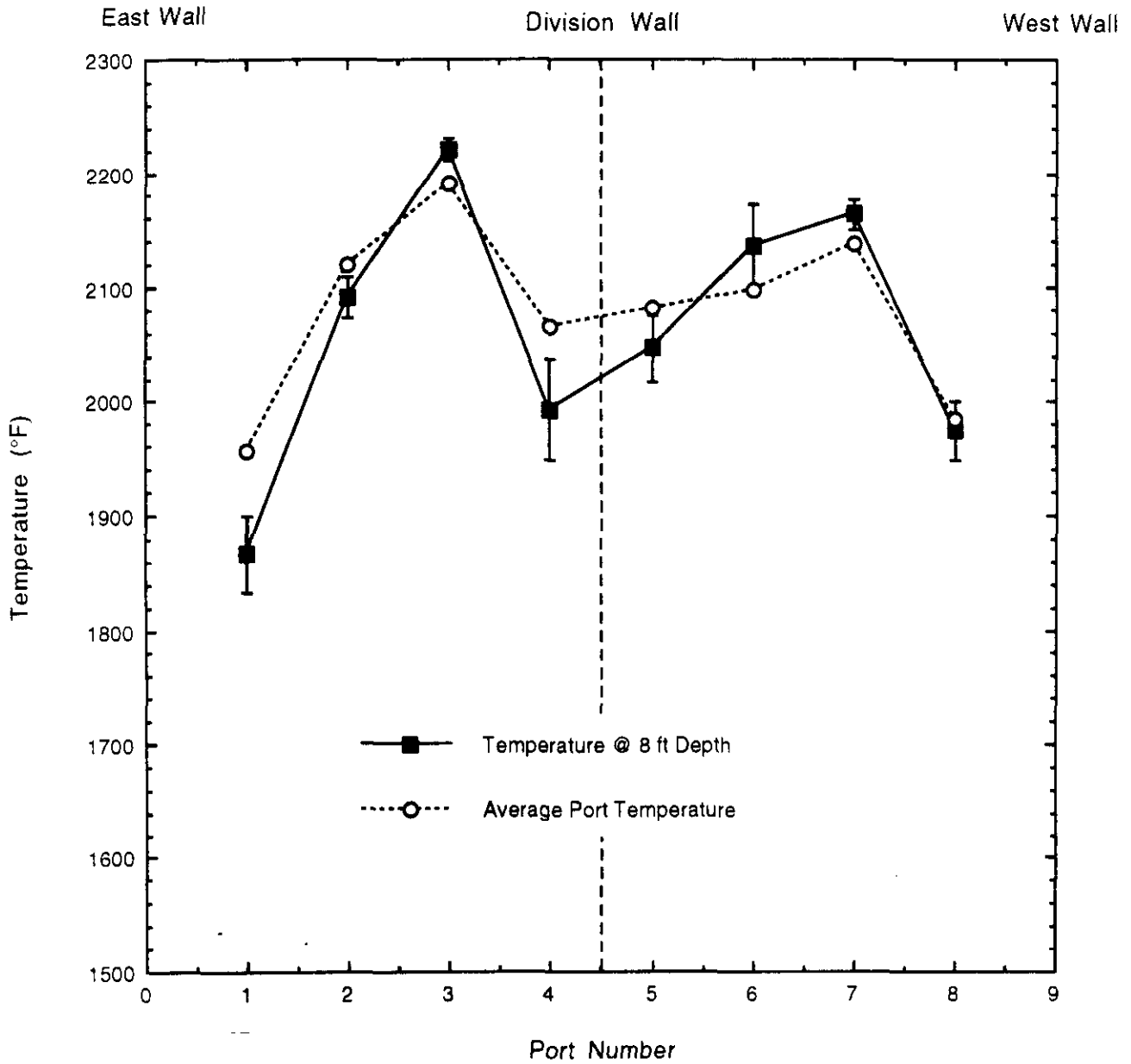
Figure 4-7. North Port Temperature Profile: 100 MWe, All Mills in Service

### 4.2.2 Cold Flow Modeling

In addition to temperature, the degree of chemical mixing with the bulk flue gas is critically important to the SNCR process. Maldistributed chemical injection results in lower overall $NO_x$ reduction and higher ammonia slip. With the appropriate temperature regions identified by the temperature measurements, the next step in the design process by NOELL, Inc. was design of the injector system. This was accomplished with cold flow modeling techniques incorporating both flow visualization and tracer gas measurements to quantify and optimize a "mixing" parameter. A 1:10 scale cold flow model of the Arapahoe Unit 4 furnace and convective section was used for this part of the design procedure. Bulk flow characteristics were examined, as well as several injection scenarios, using flow visualization and tracer gas measurements. Injection configurations were optimized using a tracer gas technique to quantify the mixing between the injected chemical and the bulk flue gas. The results of these tests are briefly summarized below, and complete documentation of the cold flow modeling effort is contained in a separate report[5].

Approach. The flue gas temperature measurements indicated that the general vicinity of the north ports provided access to the necessary urea injection temperatures over the load range (Section 4.2.1). The north ports were easily accessible (46 inches above a walkway) and represented a good location for wall mounted injectors. On the basis of this information, a scenario using two rows of wall injectors was developed. The injectors would be installed, running across the north wall of the convective section at roughly the same elevation as the north ports. One row of injectors would be installed at the exact same elevation as the north ports, pointed slightly upward, essentially parallel to the screen tubes (see Figure 4-8). Another row would be placed lower, below the screen tubes, pointed slightly downward, essentially parallel to the connective section bottom. With this injector configuration, a load following procedure was developed. The upper injector level would be used at high loads where the cavity temperature was appropriate for efficient $NO_x$ removal, and as load was reduced and temperature dropped below the optimum, the lower (i.e., hotter) level of injectors would be used. It was also anticipated that the downward oriented injectors would inject the chemical in a direction counter flow to the bulk gas flow, resulting in enhanced mixing and longer residence times. This scenario served as the basis for the cold flow modeling test procedure.

SOUTH                                                                      NORTH

SECONDARY SUPERHEATER

AVERAGE HVT
@ FULL LOAD =
1817-2231 F

FULL LOAD
(UPPER LEVEL)
INJECTOR ROW

LOW LOAD
(LOWER LEVEL)
INJECTOR ROW

AVERAGE HVT
@ FULL LOAD =
1669-1728 F
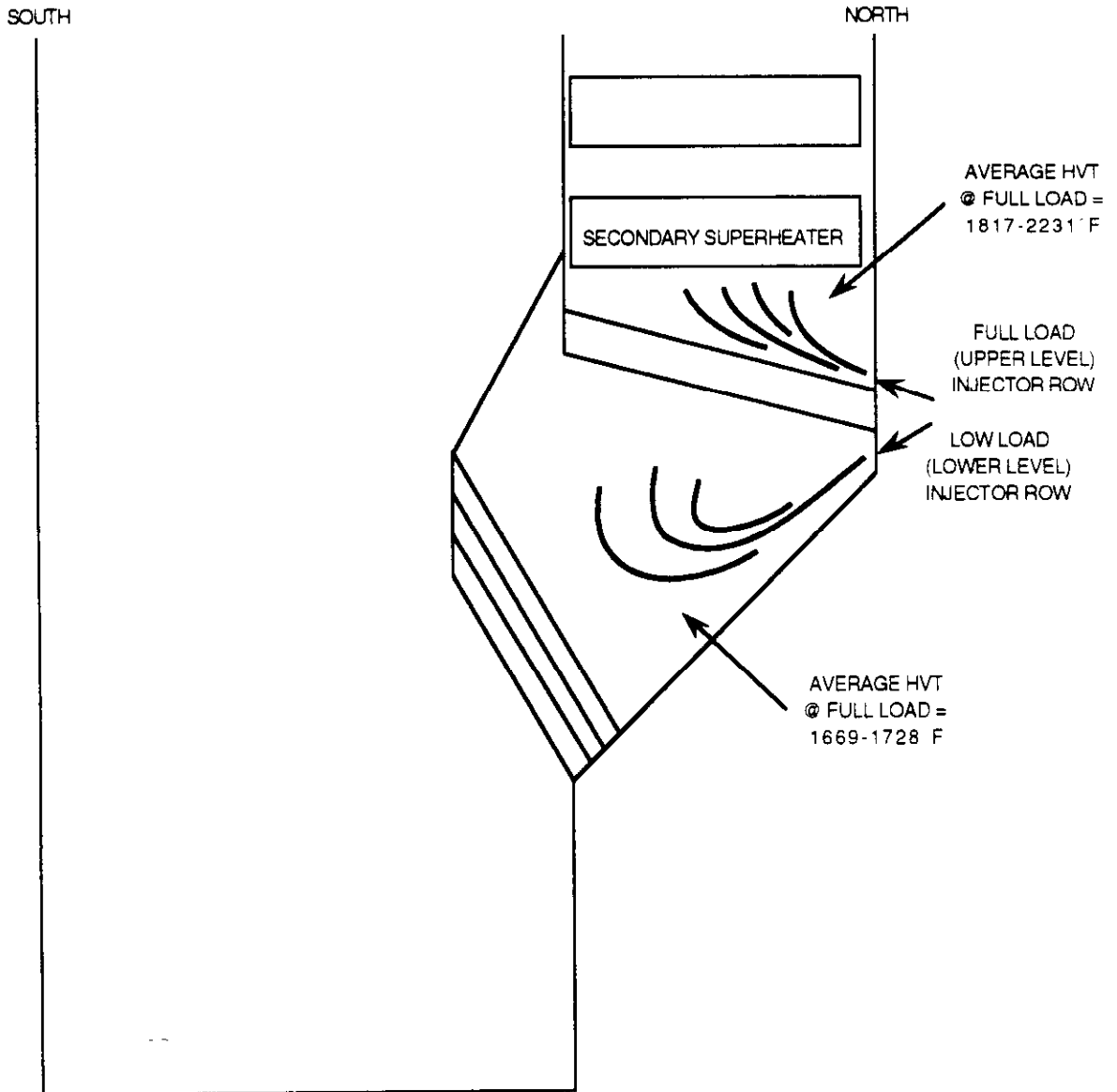
Figure 4-8.  Injector Placement Scenario Based on Flue Gas Temperature Measurements

_Methodology._ Geometric and dynamic similarity between the full-scale boiler and the 1:10 scale model were maintained for the cold flow testing. Model Reynolds numbers were kept well above 15000 to simulate the gross turbulent mixing of the full-scale system. In examining the interaction of the injection flow with the bulk flow, equivalent full-scale and model momentum ratios were maintained.

With respect to flow visualization, two techniques were used. The bulk flow patterns were obtained by seeding the main burner flow with neutrally buoyant bubbles. For the higher velocity jets, smoke was used for flow visualization.

In order to provide a basis for quantifying and comparing the degree of mixing achieved with each injection system configuration, the injection air was seeded with a tracer gas. Sixty-point sample and velocity traverses were conducted over the entire cross-sectional area of the convective section. The location at which these traverses were conducted was dependent upon the injection level, and the locations of the planes of measurement are shown in Figure 4-9. The measured concentrations were converted into a contour map to visually assess the uniformity of mixing achieved with a given injector configuration. In effect, however, this was only marginally more quantitative than flow visualization. A method was developed to better quantify mixing between different injection configurations, as well as to directly compare the measurements by negating any differences in overall tracer gas concentration or velocity distribution. This method normalizes the tracer gas measurements and accounts for a non-uniform velocity field in the overall mixing determination. The method is based on the assumption that if the flowfield was perfectly mixed, each sample point in the 60-point grid would exhibit a normalized value of one, and the standard deviation would be zero. At the other extreme, if the flowfield was totally unmixed and all of the tracer gas was measured within a single sample cell, a normalized value of 60 would be obtained in one cell, while all other sample cells exhibited a value of zero. The standard deviation of this latter case is a maximum. Intermediate levels of mixing will possess standard deviations of the normalized tracer gas concentration between these two extreme values. Each standard deviation value represents a certain mixing percentage, with zero standard deviation representing 100 percent mixed, and the maximum standard deviation representing 0 percent mixed.

SOUTH                                                   NORTH

SAMPLE AND VELOCITY
PLANE FOR UPPER
LEVEL INJECTION

SAMPLE AND VELOCITY
PLANE FOR LOWER
LEVEL INJECTION

SECONDARY SUPERHEATER

FULL LOAD
(UPPER LEVEL)
INJECTOR ROW

LOW LOAD
(LOWER LEVEL)
INJECTOR ROW
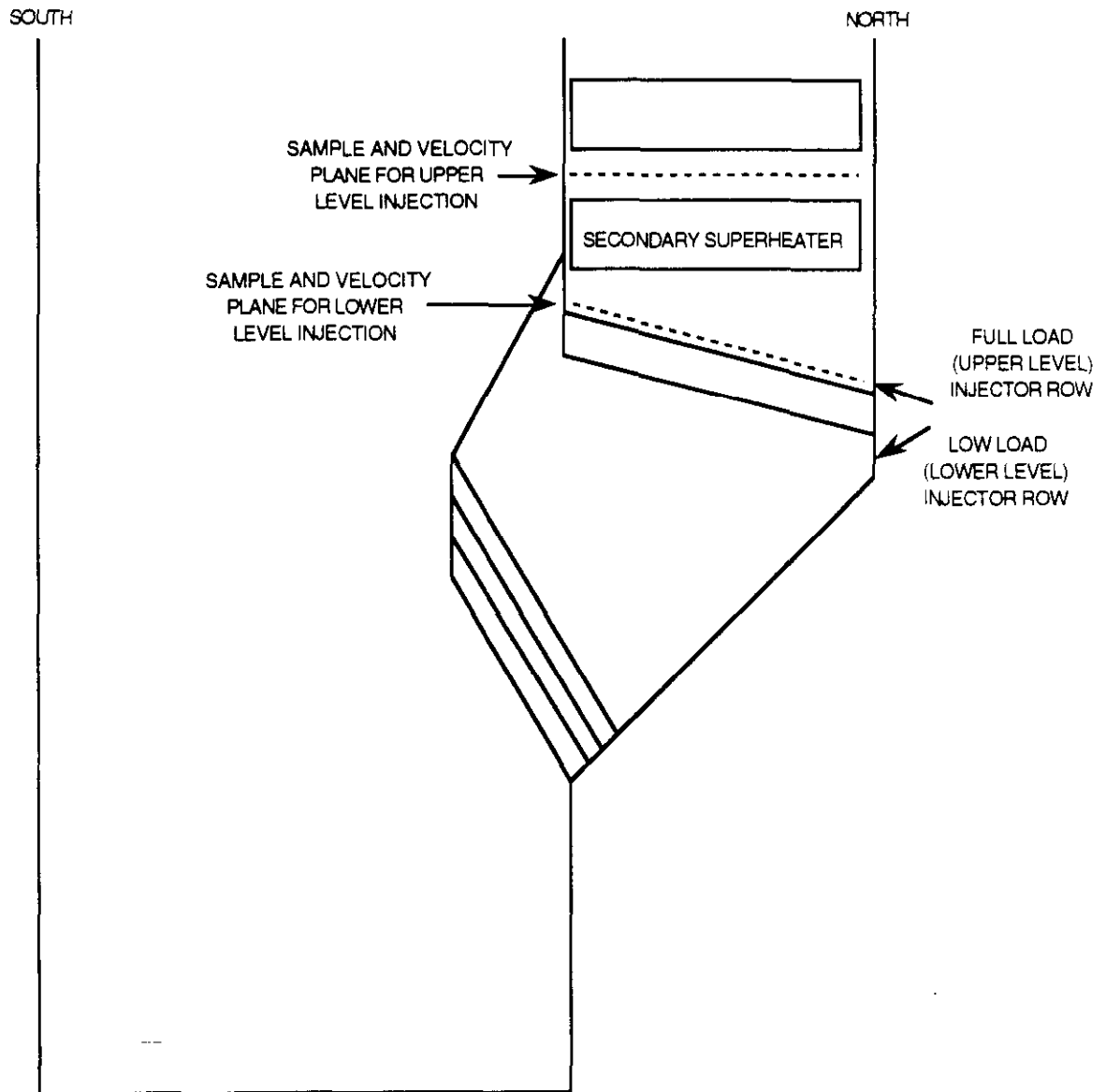
Figure 4-9.  Sample and Velocity Traverse Planes for Tracer Gas Measurements

4-15

FERCo-7034-R229

This method for quantifying the degree of mixing was used to optimize the following parameters for the upper and lower injector rows (or "levels"):

- number of injectors
- injector angle
- injector diameter
- amount of mixing air.

Results. A synopsis of the overall model bulk flow patterns is shown in Figure 4-10. At the convective section entrance, the flow encountered a 50 percent reduction in cross-sectional area as well as an immediate 180° upward turn. This resulted in a high velocity region running up against the north wall, and a large recirculation zone extending nearly halfway across the convective section. The flowfield entering the first convective tube bank was clearly non-uniform.

The design injection air flow rate was nominally two percent of the total boiler flow at full load. Previous design experience had shown this flow rate to provide high levels of mixing while not being excessive from the standpoint of compressor power costs. At full scale, the velocity at the injection nozzle is kept sonic. Thus, the evaluation of different injection configurations began by keeping the injection air flow and the injector nozzle velocity constant (thereby setting the momentum ratio constant) and varying the number of injectors. As the number of injectors changed, the jet diameter was also changed to maintain constant injection air flow. Optimizing the number of injectors involved the testing of four different scenarios: 8, 10, 12 and 20 jets. These tests were performed at the full load test condition with the upper level of injectors aimed +15° (upward) from horizontal. The results of the mixing tests are shown in Figure 4-11. As the number of jets varied, there were trade-offs between jet penetration and lateral dispersion in the east-west direction. Figure 4-11 shows that ten jets provided the highest mixing of the four cases at 71 percent. In this case, the ten jets penetrated to the middle of the plane and mixed very well laterally. Although the eight jet configuration resulted in increased penetration, the decrease in lateral mixing resulted in reduced mixing. At the other extreme, the lateral dispersion with twenty jets was good, but it was accompanied by a large decrease in penetration. These results are directly applicable to the lower injection level as well, since the variations in the lateral flowfield (east to west) was minimal as the bulk flows through the model were changed from the high load condition to the low load condition.
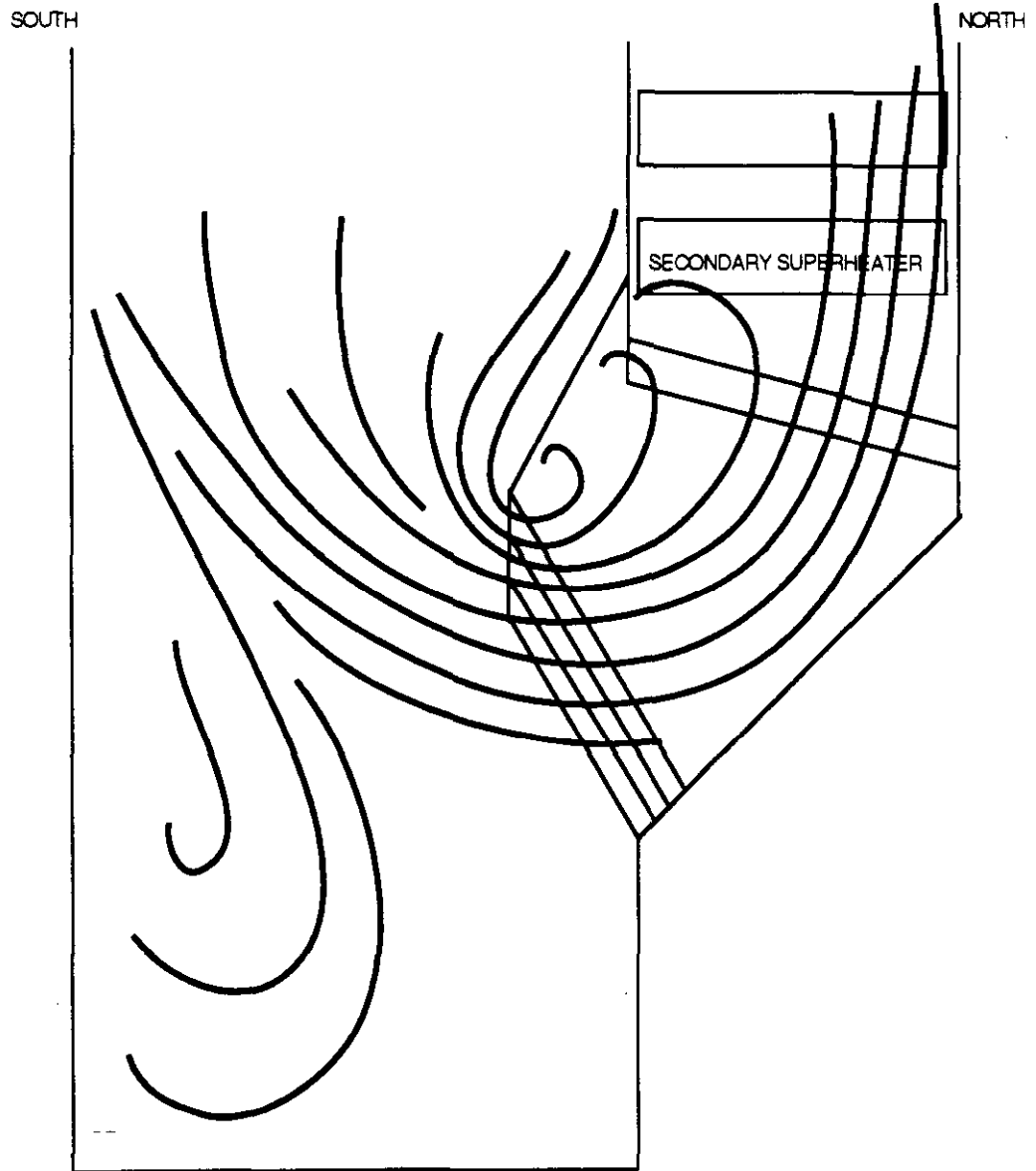
Figure 4-10. Overall Bulk Flow Patterns
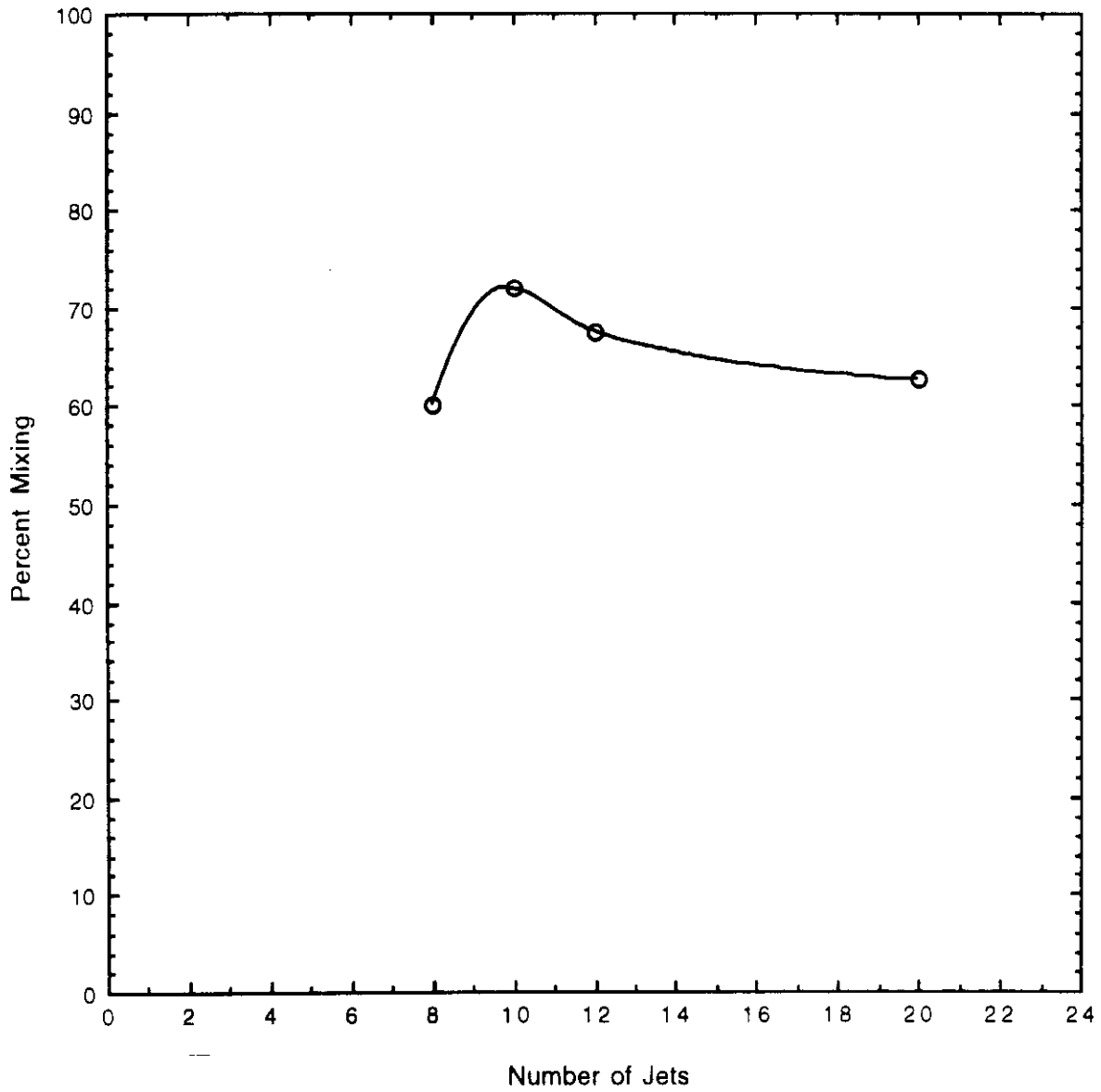
Figure 4-11. Effect of Number of Jets for Upper Level Injectors
Angled +15° from Horizontal

FERCo-7034-R229

After it was determined that 10 injectors was the optimum number, the injector angles were optimized for both levels. At the upper level, the angle was varied from -15° to +15° from horizontal with essentially no change in the mixing. As the angle was increased above +15°, the mixing degraded. Angles below -15° were not tested, since jet penetration into the upper screen tube bank was not desirable. At the lower injection level, tests were run pointing the jets directly horizontal (0°), and also directly counterflow to the bulk gas flow (-45°). Mixing was relatively poor at 59 percent with the jets aimed horizontally, but increased dramatically to 85 percent when the jets were aimed in the counterflow direction.

### 4.2.3 System Design Summary

The main conclusions reached as a result of the flue gas temperature measurement and cold flow modeling efforts are summarized below.

- Flue gas temperature measurements showed that the general vicinity of the north ports provided the necessary chemical injection temperatures. The results also indicated that two different levels of injectors were required to optimize the SNCR process over the load range. At full load an upper level would be used, while at reduced loads a lower level would be necessary. This arrangement allows chemical injection into the proper temperature zone over the load range.

- Cold flow modeling showed that at full load with the upper level injectors at approximately elevation 5306 feet (relative to sea level), mixing was optimal using the following injection configuration:

  - number of evenly spaced injectors = 10;
  - injector diameter = 1.61 inches full scale;
  - injector angle = 15° ± 5° from horizontal.

- Cold flow modeling showed that at reduced load, with the lower level injectors at approximately elevation 5302 feet, mixing was optimal using the following configuration:

  - number of evenly spaced injectors = 10;
  - injector diameter = 1.08 inches full scale;
  - — injector angle = -45°± 5° from horizontal (directly counterflow).

### 4.3 SYSTEM DESCRIPTION

The NOELL, Inc. SNCR injection system is designed to achieve a high degree of mixing between the flue gases and the reducing reagent in short residence times. This is accomplished by using a high-velocity carrier air stream. To achieve a high degree of mixing, jet velocities in the sonic

velocity range are used (about 500 to 800 fps). Aqueous ammonia or urea solutions are injected into the flue gas using a NOELL, Inc. proprietary dual-fluid nozzle. The nozzle provides deep penetration of a finely atomized solution.

Two rows of ten wall-mounted injection nozzles were installed on the Arapahoe Unit 4 boiler: one at elevation 5302'6" and one at elevation 5306'3", which placed the two levels immediately upstream and downstream of the second set of screen tubes as shown in Figure 4-12. The injection angle for the lower level of nozzles (Level 1) is oriented 45° down from horizontal and was designed to be used over the boiler operating range of 40 to 70 percent of full load. The angle of the upper level nozzles (Level 2) is 15° above horizontal, and was to be used between 70 and 100 percent of full load. The two levels are operated independently and cannot operate simultaneously. Below 40 percent load, the injection system is taken out of service as temperatures are expected to be too cold for efficient $NO_x$ removal. A schematic diagram of the urea storage and delivery system is shown in Figure 4-13.

Two insulated steel tanks are used to store a 65 percent (by weight) urea solution. The urea is continuously recirculated through electric circulation heaters to maintain a temperature of 150°F, using one of two recirculation pumps. Urea to be injected is taken from the recirculation lines, filtered and mixed with softened dilution water.

The water softening skid consists of dual softening vessels. The first vessel operates while the second is regenerating and vice versa, which allows for continuous operation. The system is controlled locally and is totally automatic.

The urea solution and dilution water are mixed at the suction side of one of two injection pumps. The injection pump pressurizes the solution up to 500 psig where it is fed into one of the two levels of injection lances which are selected automatically. The urea injection lines are insulated and heat traced at 50°F to prevent crystallization. The urea injection pumps are operated with variable speed drives, and the total liquid flow (urea solution and dilution water) is set by the pump speed and can be varied from nominally 7 to 28 gpm. The urea flow is then controlled using a control valve to control the urea flow to the suction side of the pump.
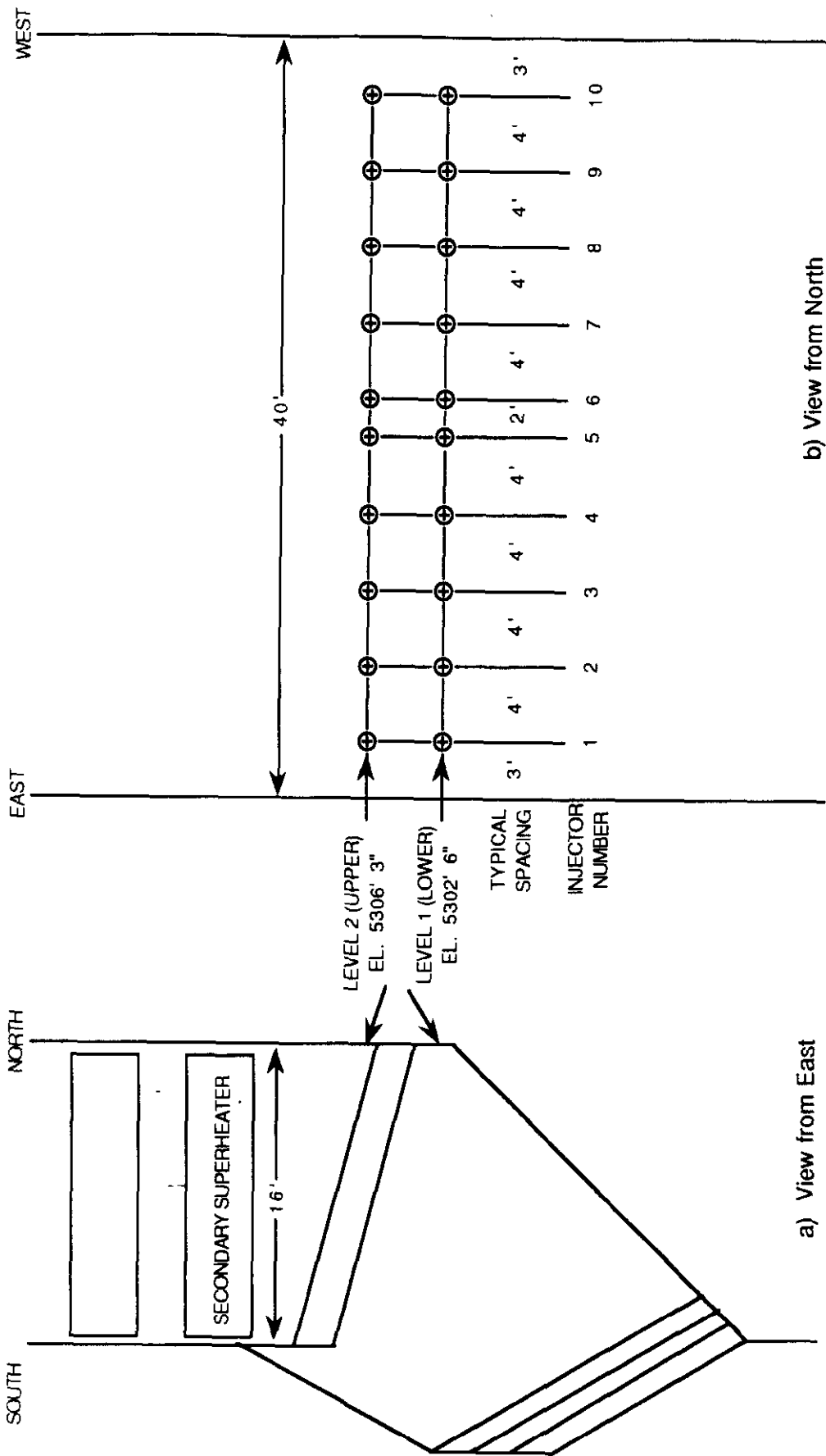
Figure 4-12. Arapahoe Unit 4 SNCR Injection Nozzle Location

b) View from North

a) View from East

FERCo-7034-R229
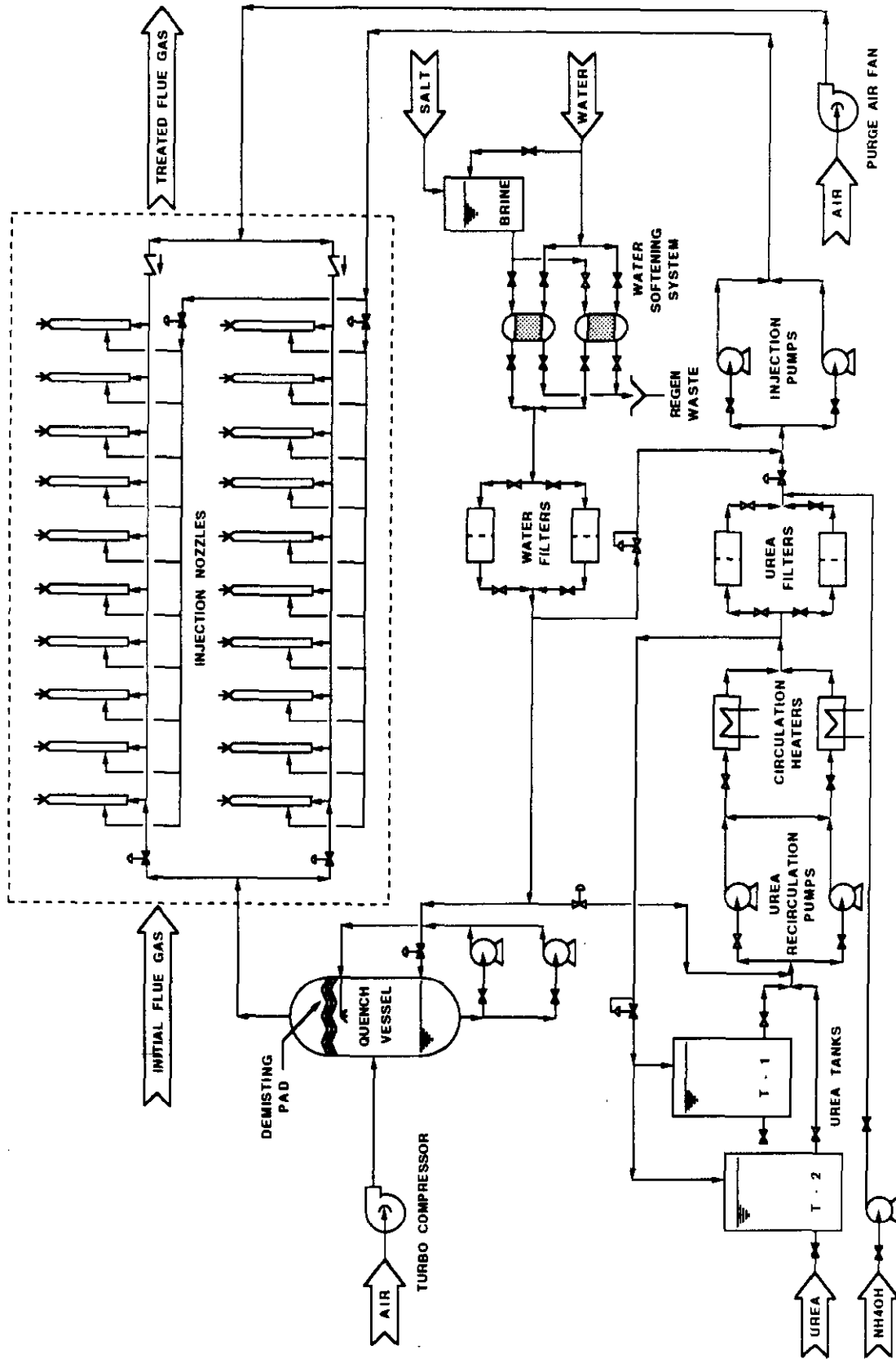
Figure 4-13. Urea Storage and Delivery System Flow Diagram

FERCo-7034-R229

The mixing air is supplied by a single stage centrifugal compressor which draws ambient air through a filter and silencer. The compressor can supply up to 9200 scfm of air at 13 psig. The volume of air supplied is controlled by variable inlet guide vanes and a variable diffuser assembly, which automatically delivers a preset discharge pressure. Upon exiting the compressor, the air passes through a quench vessel which cools the hot compressed air by recirculating, spraying, and evaporating water. The quench skid has redundant pumps for water recirculation, and the water level within the quench vessel is maintained automatically by a switch operated solenoid valve.

Purge air is used to keep the level of injection lances not in service cool and free of ash build up. The air is supplied by a purge air fan which draws ambient air through a filter and silencer. The air is fed through the air lines not in use, up to the air header on the level not injecting urea, and then through the nozzles.

The urea injection system is controlled by a programmable logic controller (PLC). The PLC is operated using an IBM compatible computer and controls all the functions of the system (equipment on/off, valves open/close, etc.), except for three local control systems in local control panels (LCPs); the centrifugal compressor, the circulation heaters and the water softening skid. These LCPs control the equipment and receive the main commands and transmit the key information to and from the PLC.

Some of the valves need manual pre-selection for redundant equipment, i.e., urea recirculation pump, quench pump, or filter inlet and outlet valves. However, the PLC secures the function of the equipment if a valve is not positioned correctly.

From the local computer, the SNCR system can be either manually set, or operated under automatic control. Under automatic control operation, the urea flow rate is set by a feed forward control function using a boiler load signal. The system also utilizes feedback control to trim the urea flow rate by $\pm 30$ percent. The feedback control loop can use either a stack $NO_x$ signal or a stack $NH_3$ signal.

During the baseline SNCR tests, aqueous ammonia ($NH_4OH$) was tested as well as urea. Since the $NH_4OH$ tests were not originally planned and were conducted over a short period of time, temporary $NH_4OH$ storage was provided on site. For this test period, the $NH_4OH$ was stored in a tanker truck, and a small transfer pump was used to pump the solution (29.4 weight percent as $NH_3$) from the

tanker truck to the suction side of the injection pump (upstream of the control valve, as shown in Figure 4-13). All other control functions remained the same as when operating with urea.

# 5.0 RESULTS

## 5.1 OBJECTIVES

The objectives of the baseline SNCR tests were twofold. First, to start up and check out the functional performance of the SNCR hardware. Second, to provide a preliminary characterization of the SNCR process performance with the original combustion system on the Arapahoe Unit 4 boiler. This will then serve as a basis of comparison of the combined low-$NO_x$ combustion/SNCR system to the use of SNCR alone.

The baseline SNCR test program had to coordinate with the overall retrofit schedule for the Arapahoe Unit 4 boiler. This only provided for a five (5) week test program from February 4 to March 6, 1992, prior to the outage scheduled for the low-$NO_x$ combustion system retrofit. Due to this short time period, which had to accommodate both the SNCR start up and test activity, it was not possible to completely optimize the injection system. However, it was possible to perform a limited parametric investigation of the following parameters.

Boiler Load (Temperature, Residence Time)
- 60 to 110 MWe

SNCR Chemical Type
- Urea
- Aqueous Ammonia ($NH_4OH$)

SNCR Chemical Injection Rate
- N/NO Molar Ratio = 0 to 2.0 (nominal)

SNCR Injection System Parameters
- Injection Location (Level 1, Level 2)
- Mixing Air Flow Rate (1700 to 4800 scfm)
- Dilution Water Flow Rate (7 to 28 gpm)
- Mixing Air Orifice Size
- Liquid Orifice Size
- Number of Injectors in Service

Boiler load is an important process parameter from the perspective that it is the predominant factor which determines the flue gas temperature at the injection location. Thus, an assessment of the system performance over the load range essentially defines process response over a range

FERCo-7034-R229

of injection temperatures. Variations in boiler load will also have an effect on system performance by affecting the amount of time that the injected chemical spends at a particular location in the boiler. As the boiler load decreases, the flue gas flow rate decreases and the residence time increases. Although changes in residence time resulting from variations in boiler load can be significant, the change in local flue gas temperature will have the dominant effect from the perspective of SNCR process performance. For the current study, unit load was varied from 60 to 110 MWe.

The original test plan called for testing only with urea. However, recent full-scale tests[4] have shown that aqueous ammonia ($NH_4OH$) can provide increased system performance compared to that for urea in certain temperature ranges. This coupled with initial urea test results showing NO removals which were somewhat lower than expected, resulted in the desire to compare the performance of the two chemicals on a side-by-side basis. Due to the logistics involved in obtaining the chemical, only two days were available for testing $NH_4OH$ at the conclusion of the test program. Thus, only a cursory comparison of the performance of the two chemicals was possible during this test series.

The limited time available for the baseline urea test program did not allow for comprehensive optimization of the five injection process parameters indicated above (injection location, air and liquid flow rates, and air and liquid orifice sizes). Early tests at the Level 2 injection location showed the region to be too cold for urea injection, even at full load. Thus, the majority of the test effort focused on Level 1 injection. The effect of nozzle parameters (i.e., mixing air and liquid orifice sizes) were shown to have little impact on process performance when compared to the impact of mixing air and water dilution flow rates, thus allowing the allocation of more time to study the two latter effects.

Before presenting the test results, it is of value to discuss the impacts that the various SNCR injection parameters can have on the process. In some cases, these effects are coupled and may have offsetting impacts on the overall SNCR process. Changing an injection system parameter can 1) change the overall level of mixing of the chemical with the combustion products, 2) change drop size and thus evaporation times, 3) change local temperatures, and 4) change the location in the furnace where the chemical mixes with the combustion products. The general effect of these various changes are summarized in Table 5-1.

As is apparent from Table 5-1, changing an injection parameter can impact the process in a number of ways. For instance, increasing the mixing air flow rate, while potentially increasing the mixing, will also provide localized cooling of the combustion products. Thus, depending upon the local temperatures, increasing the mixing air flow rate may or may not have an overall beneficial effect on the SNCR process performance.

Table 5-1

GENERAL EFFECTS OF INJECTION SYSTEM PARAMETERS

| Increasing | Jet Penetration | Overall Mixing | Drop Size | Local Temperature |
|---|---|---|---|---|
| Mixing Air Pressure[1] | + | + | - | - |
| Dilution Water Flow | + | 0 | - | - |
| Air Orifice Size[2] | - | - | + | 0 |
| Liquid Orifice Size[3] | + | 0 | + | 0 |

[1] Same air orifice size increases air flow rate
[2] Same air flow rate decreases injection velocity
[3] Same liquid flow decreases atomization

Localized cooling of the flue gas occurs when the air/liquid mixture is injected due to 1) energy required to heat the mixing air, 2) energy required to vaporize the liquid and 3) energy required to heat the vaporized liquid to the local combustion product temperature. Table 5-2 summarizes the nominal cooling effects for a range of injection system parameters; the local cooling effect can range from 60 to 127°F at full load conditions depending on the injection system parameters. The cooling effect can be higher at lower boiler operating loads.

Table 5-2

SUMMARY OF LOCAL COMBUSTION GAS COOLING BY THE SNCR INJECTION JETS

| Load (MWe) | Injection Parameters | | Calculated Localized Cooling, ΔT (°F) |
|---|---|---|---|
| | $P_{Air}$ (psig) | $Q_{Liq}$ (gpm) | |
| 100 | 12 | 28 | 127 |
| 100 | 12 | 18 | 95 |
| 100 | 12 | 6 | 57 |
| 100 | 8 | 28 | 120 |
| 100 | 1.5 | 28 | 102 |

Before the results are presented, it is also worthwhile to discuss how the tests were actually run and, in particular, how the chemical injection rate was defined. The relative chemical feed rate for a particular test is indicated by the N/NO molar ratio (i.e., the molar ratio of the amount of nitrogen injected to the amount of NO in the untreated flue gas). Before each test, a target N/NO ratio was decided upon, and a baseline NO level measured at the economizer exit. From these two values, a chemical feed rate was calculated and the injection pump speed and urea control valve settings determined. At the conclusion of the test, the N/NO ratio was calculated from the average urea flow and baseline NO level. Since the urea flow may vary slightly over the duration of a test, and the baseline NO level may vary over the course of the day (baseline NO levels were not checked after each individual test, but periodically throughout each day), the calculated N/NO ratio was often slightly different than the target value. Throughout the text of this report, the target (or nominal) N/NO ratios will be utilized in the discussion of test conditions (i.e., a nominal N/NO ratio of 1.0 will indicate a calculated N/NO ratio in the region of 0.9 to 1.1).

## 5.2    FURNACE EXIT GAS TEMPERATURE

As noted above, the initial results of the urea injection tests indicated NO removals which were somewhat lower than expected. Acoustic temperature measurements showed that the furnace exit gas temperatures were significantly lower than those measured previously in support of the SNCR system design phase (Table 4-2). Both sets of data collected with the acoustic instrument at Port G (recall Figure 4-4) are plotted in Figure 5-1, along with similar measurements made during the baseline burner tests. The data collected during the baseline burner and baseline SNCR tests agree well with each other, but are on the order of 150 to 200°F lower than those measured in April, 1991.

The reason for the decrease in temperature seen between April and November, 1991, is not clear. Although there was a unit outage from September 27 to October 13, only a simple boiler inspection was performed and no physical or chemical cleaning of the furnace or convective sections took place. It is possible that the furnace "cleaned itself" during the contraction and expansion associated with the shut-down and start-up of the boiler. If this occurred and the furnace walls were significantly cleaner after the outage than before, the furnace wall heat transfer would increase, and the furnace exit gas temperature would be reduced. However, other than
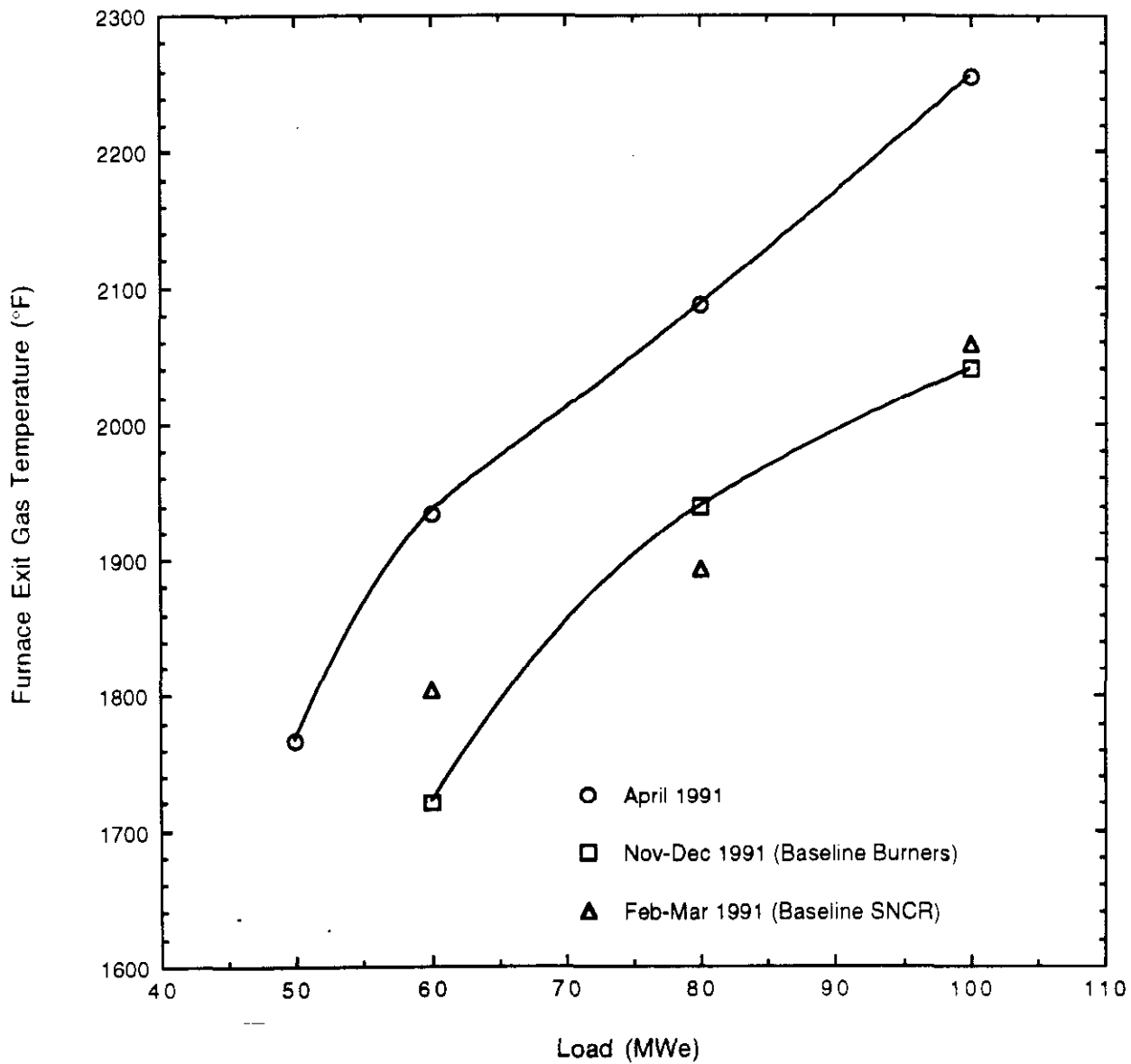
Figure 5-1. Variation of Furnace Exit Gas Temperature with Time
(Acoustic Measurements at Port G)

the temperature measurements discussed above, there is no solid evidence supporting this hypothesis.

A temperature reduction on the order of 150 to 200°F could have a major impact on SNCR process performance when the width of the urea injection temperature window (1650 to 1950°F) is considered. As will be shown in the following section, early tests at the Level 2 injection location showed the region to be too cold for urea injection even at full load; thus, the majority of the test effort focused on the hotter Level 1 injection location.

## 5.3 UREA INJECTION AT LEVEL 2

As noted above, only a brief amount of testing was conducted with the Level 2 injectors as the temperature was found to be too low for adequate performance with urea. The results of the Level 2 urea injection tests are shown below in Table 5-3. The tests were performed at 100 MWe with a fixed total liquid flow rate of 28 gpm. At N/NO ratios of nominally 1.0, NO removal was less than 30 percent and the $NH_3$ slip was unacceptably high. The excessively high $NH_3$ slip result indicates that from a process perspective, injection at the level 2 location was on the low side of the optimal urea temperature window, and/or the residence time was too low.

Table 5-3

SUMMARY OF NO REMOVALS WITH UREA INJECTION
WITH THE LEVEL 2 INJECTORS
(Load: 100 MWe, Air Orifice: 1.625", Liquid Orifice: 0.09375")

| Test Number | Total Liquid Flow (gpm) | Mixing Air Pressure (psig) | N/NO (molar) | NO Removal (%) | $NH_3$ Slip (ppm) |
|---|---|---|---|---|---|
| 55 | 28 | 12 | 1.13 | 24.1 | N/A |
| 58 | 28 | 12 | 1.02 | 26.7 | 294 |
| 59 | 28 | 8 | 1.01 | 26.1 | N/A |

During these initial tests at Level 2, some point-by-point measurements were taken at the sampling grid located at the economizer exit. Recall in Figure 3-2 that twelve probes, six along the duct width at two depths, were installed to allow composite sampling at the economizer exit.

By sampling point-by-point, information could also be obtained on the distribution of urea and local NO removals. For instance, the probes located towards the bottom of the duct would provide an indication of the NO removal for gas towards the north wall, or near the injectors. The top row of probes would provide information on chemical distribution for the combustion product gas far from the injectors. Figure 5-2 shows the results of HVT temperature measurements made through the north ports along the width of the furnace near the SNCR injectors during the system design phase in April, 1991. These measurements were taken at a depth of 8 feet, which is close to the center line of the convective pass in the north-south direction (the total depth of the duct at the north port location is approximately 16 feet). As can be seen, there are cool regions near the outer walls and a cool region near the center of the boiler. The cool region in the center is likely due to the division wall in the furnace. Figure 5-3 shows the point-by-point measurements of the local NO concentrations made through the economizer exit probes, without urea injection. Figure 5-4 shows the local NO removals with urea injection at a nominal injection rate of N/NO = 1.0. Figure 5-4a is data for mixing air pressure of 12 psig, while Figure 5-4b is data for a reduced mixing air pressure of 8 psig. At a pressure of 12 psig, the mixing air flow rate is nominally 4800 scfm; while at a pressure of 8 psig, the mixing air flow rate is reduced to nominally 3900 scfm. In Figures 5-2 through 5-4, the locations of the ten injectors are indicated by the "x"'s across the top of each figure.

From the results shown in Figures 5-4a and 5-4b, it can be seen that the local NO removals along the width of the furnace follow the general temperature profile shown in Figure 5-2, with peak removals occurring in the higher temperature regions of the furnace. The temperatures of 2150 to 2230°F, where the maximum local NO removals occur, may at first glance appear to be outside the SNCR temperature window. However, it must be realized that the temperature measurements were made in April of 1991, and therefore indicate temperatures which are in the range of 150 to 200°F high. Also, the urea injection tests were conducted at a total liquid flow rate of 28 gpm and mixing air flow rates of 4800 and 3900 scfm. The energy required to vaporize the liquid and heat the air result in local cooling of the combustion gases by 120 to 130°F. The results in Figure 5-4a indicate that NO removals were highest for the top set of probes at the economizer exit grid. These probes sample the gas which tends to be on the south wall of the convective section, away from the injectors. This would suggest that the injection jets are over-penetrating and not

Figure 5-2. 100 MWe North Port Temperature Profile at 8 ft. Depth
(HVT Measurements from April, 1991)
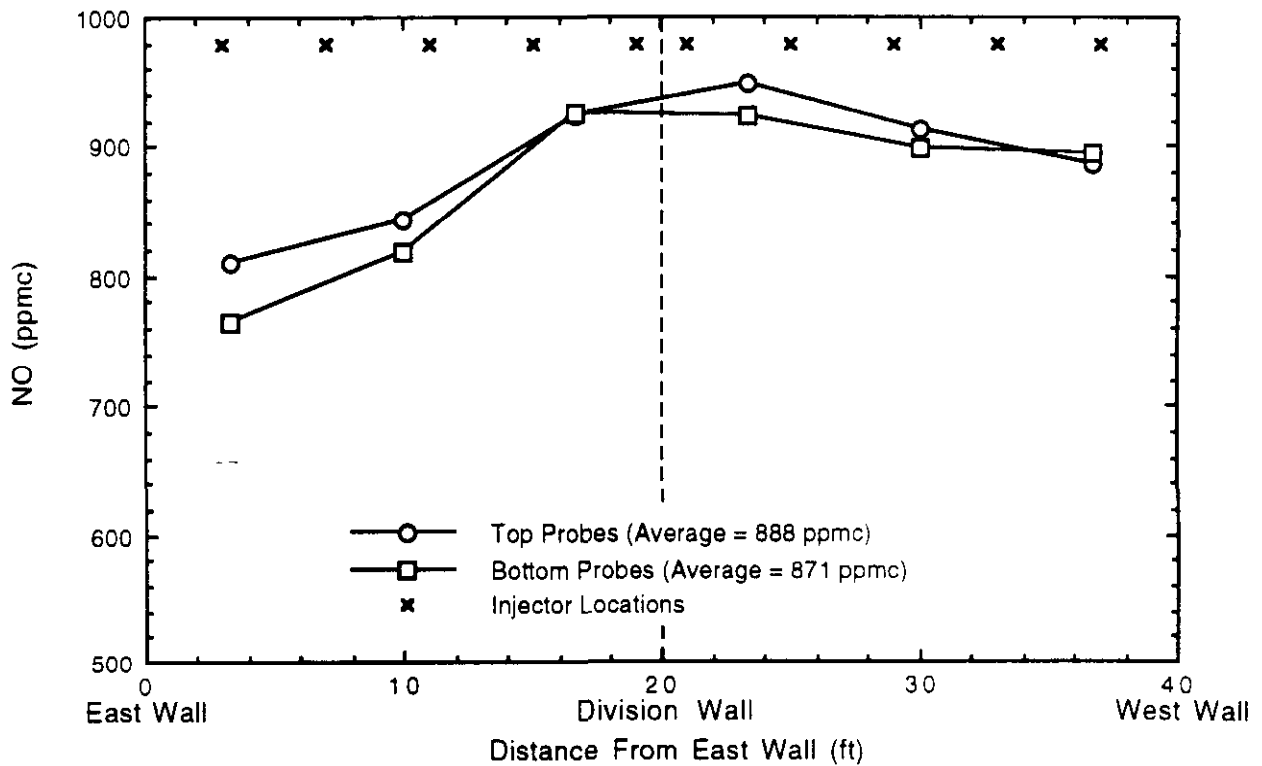


Figure 5-3. 100 MWe Baseline Economizer Exit NO Profiles for Point-by-Point
Test with Level 2 Urea Injection

5-8
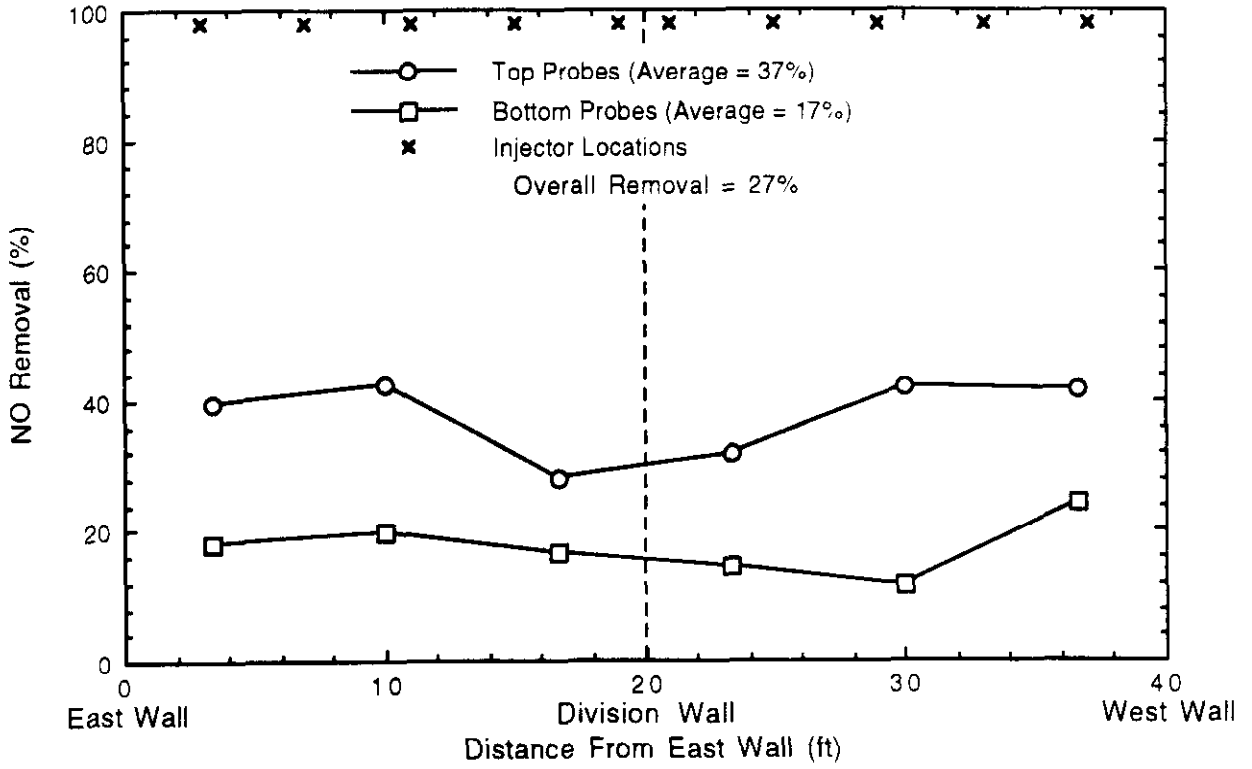
a) Mixing Air Pressure: 12 psig (4800 SCFM)
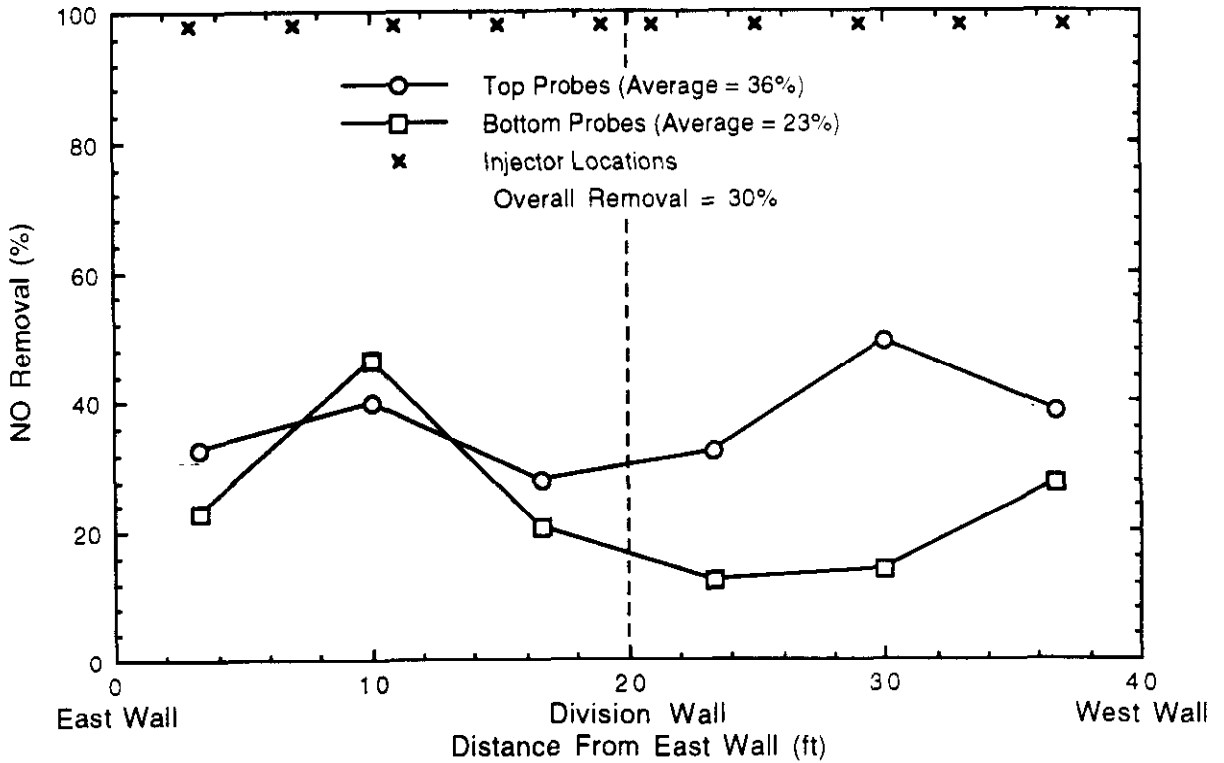


b) Mixing Air Pressure: 8 psig (3900 SCFM)

Figure 5-4. NO Removal Profiles for Level 2 Urea Injection
(100 MWe, N/NO = 1.0, 28 gpm Total Liquid Flow)

5-9

entraining and mixing sufficiently with the combustion gases near the north wall. Recall that the cold flow modeling results showed that upon making the 180° turn into the convective section, the combustion products tended to be forced out to the north wall. When the mixing air pressure was reduced from 12 to 8 psig, the NO removals near the north wall increased (bottom probes in Figure 5-4b), at least on the east half of the furnace. The NO removals on the west half of the furnace remained about the same.

## 5.4    UREA INJECTION AT LEVEL 1

The majority of the baseline SNCR testing was conducted using the Level 1 injectors, as this location provided higher NO removals for a fixed amount of $NH_3$ slip than the Level 2 location. In presenting the results, a discussion of the local point-by-point NO removals will be presented first, as a significant amount of insight can be gained from examination of this data. This will be followed by a discussion of the primary parameters that affect SNCR performance (boiler load, N/NO ratio, and dilution water and mixing air flow rates).

### 5.4.1   Local NO Removals

As was done with the Level 2 testing, a limited number of tests were conducted with point-by-point measurements at the economizer exit. Figure 5-5 shows the baseline point-by-point NO measurements for a boiler load of 100 MWe. Point-by-point NO removals are shown in Figure 5-6 for urea injection at a nominal N/NO ratio of 1.0, a total liquid flow rate of 28 gpm and mixing air pressure of 8 psig. Again, recall that the "top probes" sample gas more representative of the combustion products towards the south wall, away from the injectors. Two observations are evident relative to the point-by-point measurements made with urea injection at Level 2. The first is that the average NO removals increased from 30 to 50 percent when using the Level 1 injectors. The increase is due to injecting into a zone of higher flue gas temperature. Secondly, higher removals with Level 1 injection occur on the outer walls and in the center of the furnace which are the cooler regions of the furnace (recall Figure 5-2). During the Level 2 injection tests, higher NO removals occurred near the center of each half of the boiler away from the cooler walls. This indicates that at full load conditions of 100 MWe, Level 1 injection is on the high side of the urea temperature window.
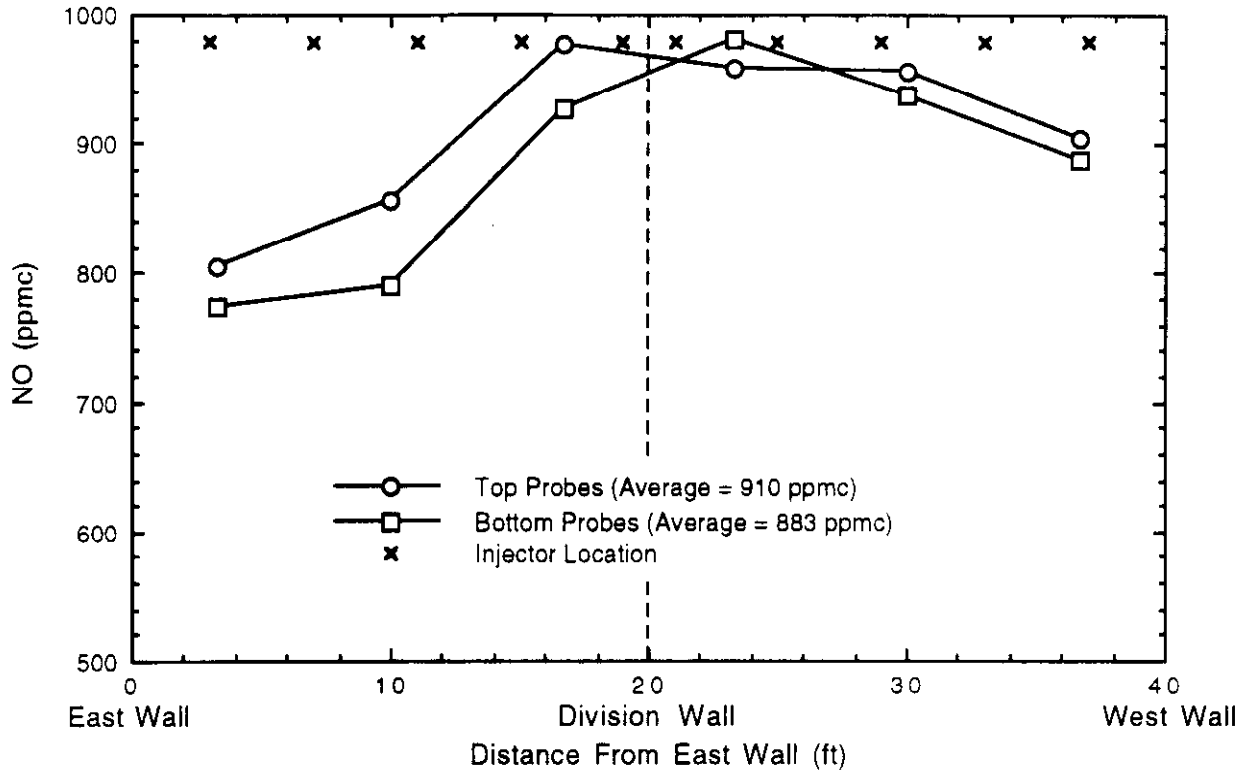
Figure 5-5. 100 MWe Baseline Economizer Exit NO Profiles for
Point-by-Point Test with Level 1 Urea Injection
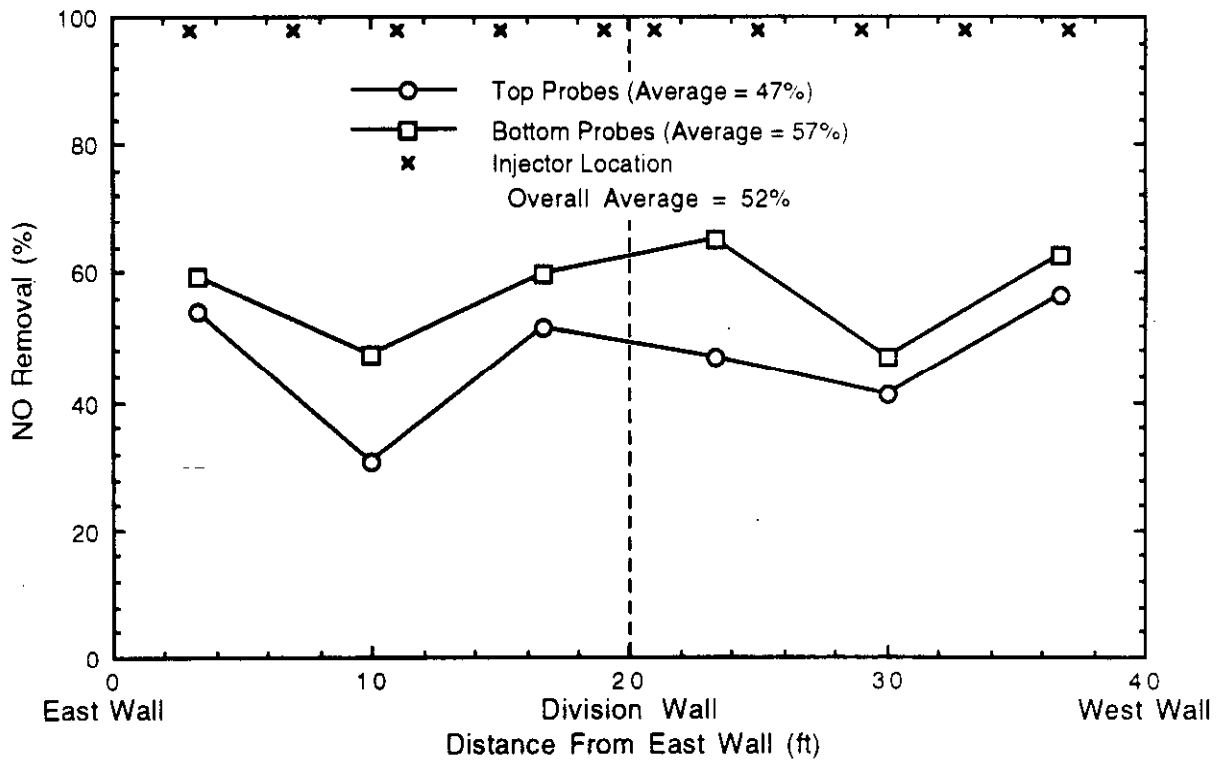


Figure 5-6. NO Removal Profiles for Level 1 Urea Injection
(100 MWe, N/NO = 1.0, 8 psig Air, 28 gpm Total Liquid Flow)

5-11

Additional spatially resolved data was collected during the test program focusing primarily on the east-to-west variations in NO removal due to the influence of the furnace walls. By sampling three different groups of four probes, this data could be collected in a much shorter time than that required by the point-by-point traverses. The four probes in the center of the economizer exit grid (numbers 5 to 8 in Figure 3-2) were used to sample the region near the division wall, while the four outside probes sampled the regions near the two outside walls. The remaining four probes (numbers 3, 4, 9 and 10) were combined to sample the higher temperature regions in the center of each side of the boiler. Figure 5-7 shows the east-to-west variation in NO removal as a function of mixing air pressure for 8 and 12 psig. No effect of injection air pressure is seen in terms of east-to-west variations. This is expected since any change in mixing air flow rate will primarily impact jet penetration, which will only be seen in the north-south direction.

Comparable east-west spatial variations were also seen at a reduced boiler load of 80 MWe. Figure 5-8 shows the east-west temperature profile obtained through the north ports at a depth of 8 feet during the SNCR system design phase. The trends are similar to those seen in Figure 5-2, with cooler temperatures in the regions near the east, west and division walls. Figure 5-9 shows the east-west variation in NO removal for a nominal urea injection rate of N/NO = 1.0, total liquid flow rate of 28 gpm and mixing air pressure of 8 psig. At this lower operating load, not as great an east-west variation was seen as at 100 MWe. Although similar to 100 MWe, higher NO removals were observed in the cooler regions of the furnace.

The spatial variation in temperature and NO removal shown above indicates that optimization of the injection system may be possible by varying the specific injectors in service at a given load. This level of optimization was beyond the scope of the present test series. However, a brief test series was conducted at a boiler load of 80 MWe and the results are shown in Figure 5-10. For the test conditions shown, operation with all ten Level 1 injectors in service resulted in a NO removal of 48 percent. Stopping the urea flow to the two injectors in the center of the furnace (Numbers 5 and 6) decreased the NO removal by approximately 6 percent, while the total liquid flow was held constant. No effect was seen when the flow to the two outermost injectors (Numbers 1 and 10) was stopped, as NO removal remained at 48 percent.

During the retrofit test program, further optimization of the injection system by varying orifice sizes and the number of injectors in service will be performed.

FERCo-7034-R229

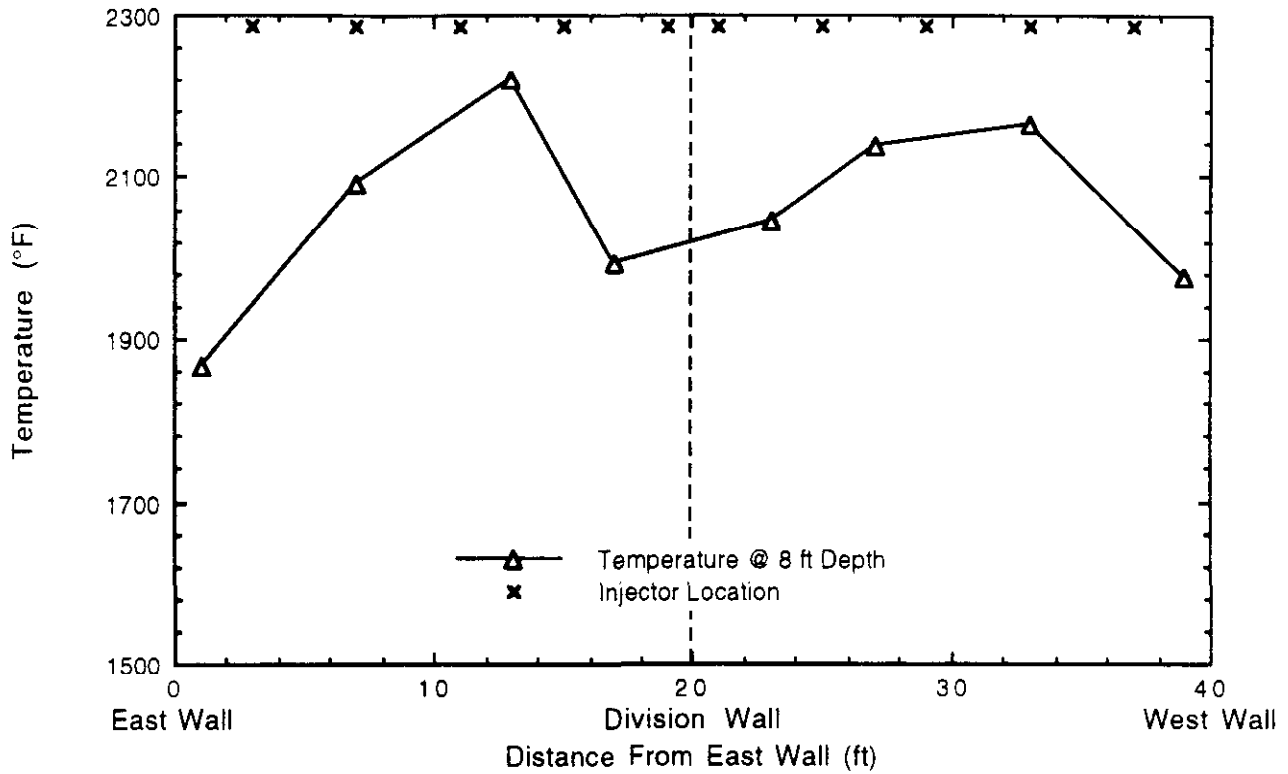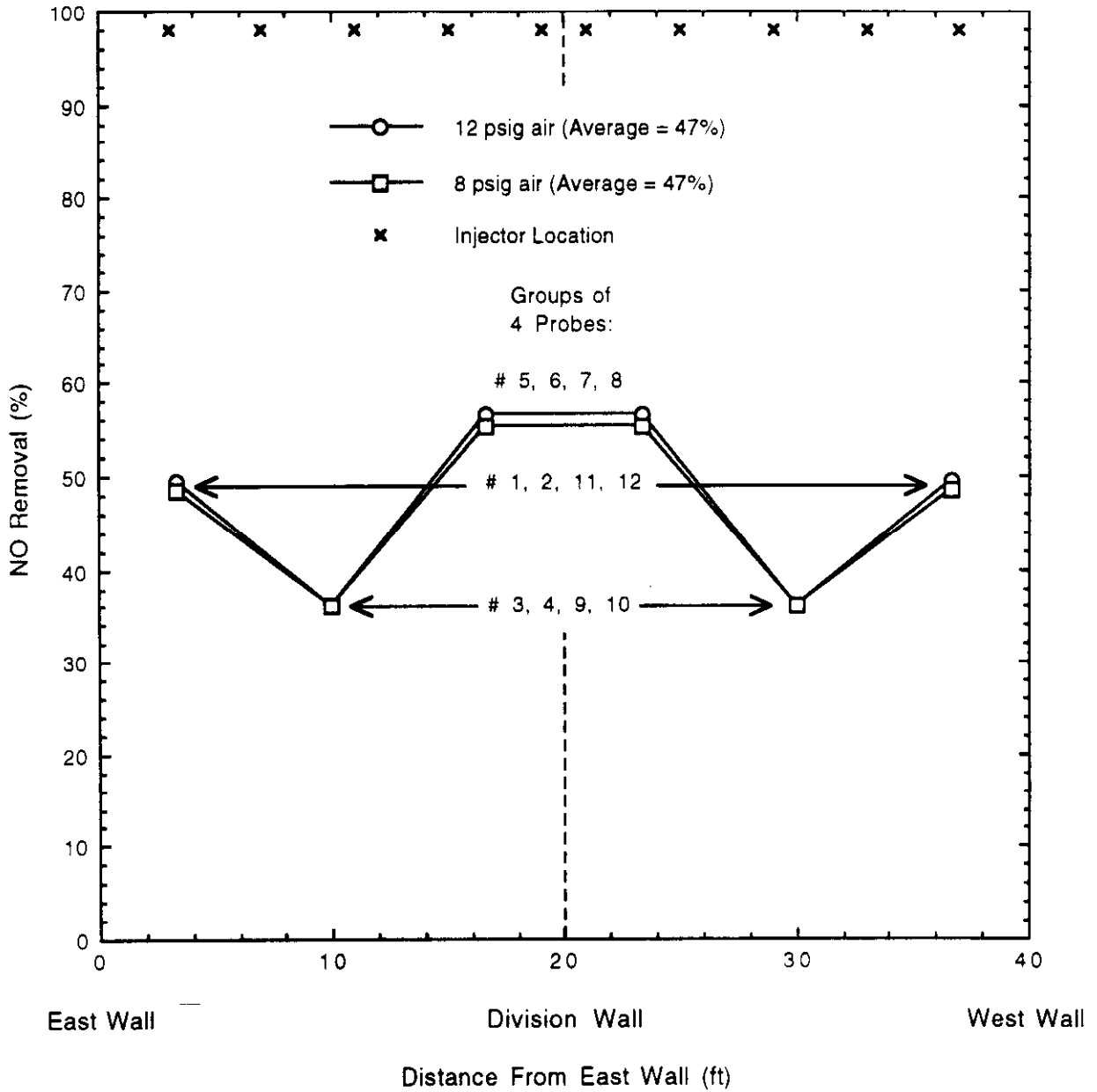Figure 5-7. Effect of Urea Injection Air Pressure (100 MWe, Level 1 Injection, N/NO = 1.0, 28 gpm Total Liquid Flow)
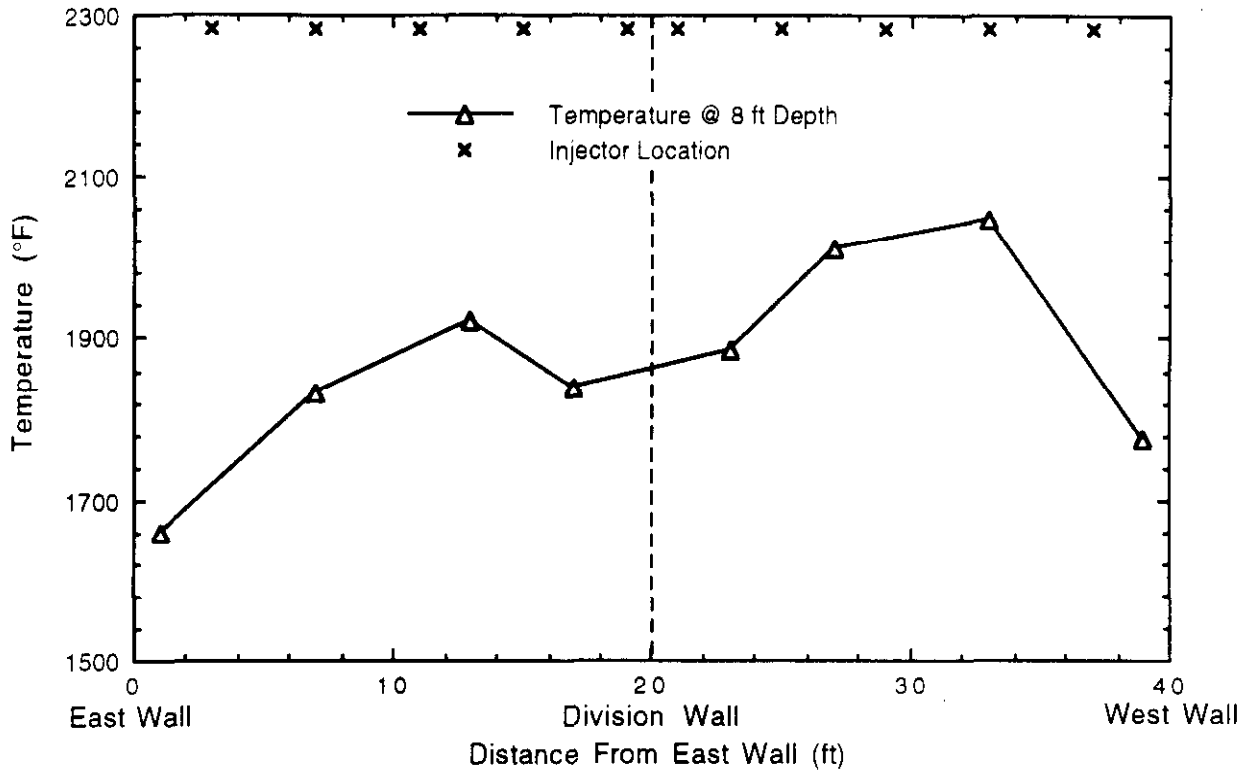
Figure 5-8. 80 MWe North Port Temperature Profile at 8 ft. Depth
(HVT Measurements from April, 1991)
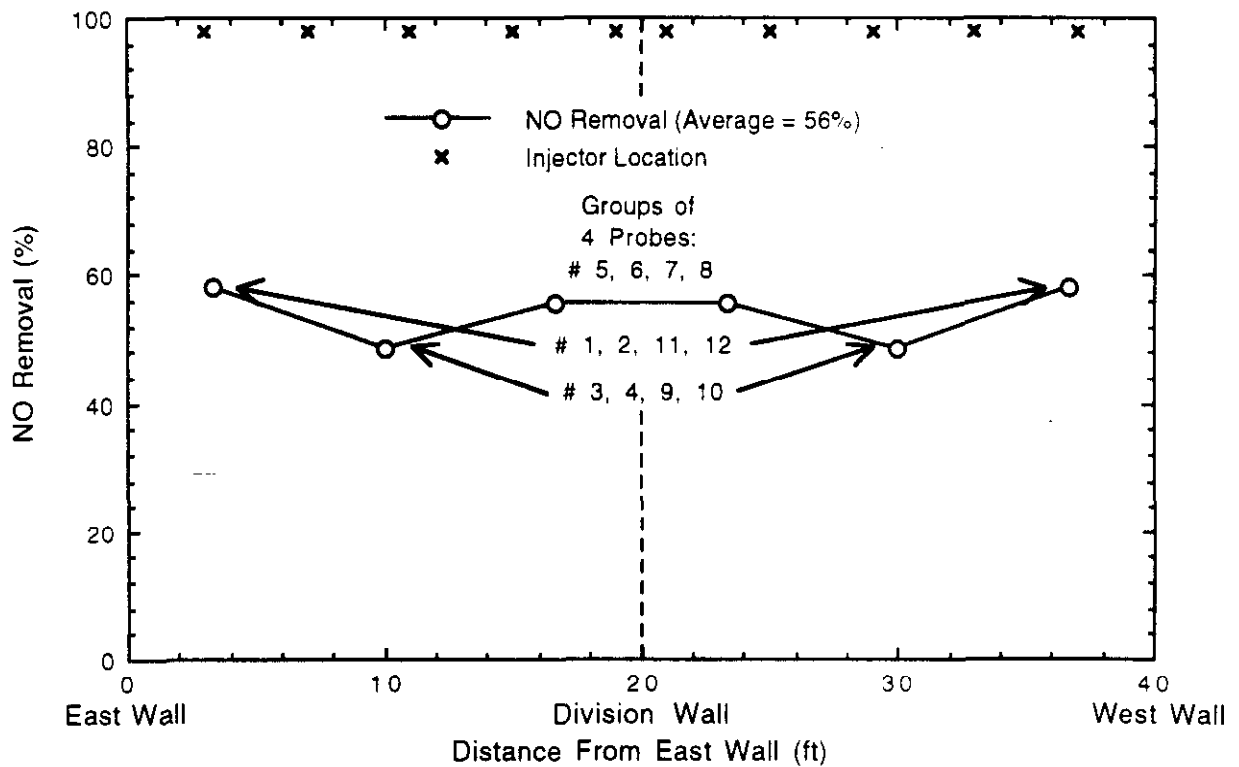


Figure 5-9. NO Removal Profile for Level 1 Urea Injection at 80 MWe
(N/NO = 1.0, 8 psig Air, 28 gpm Total Liquid Flow)

5-14
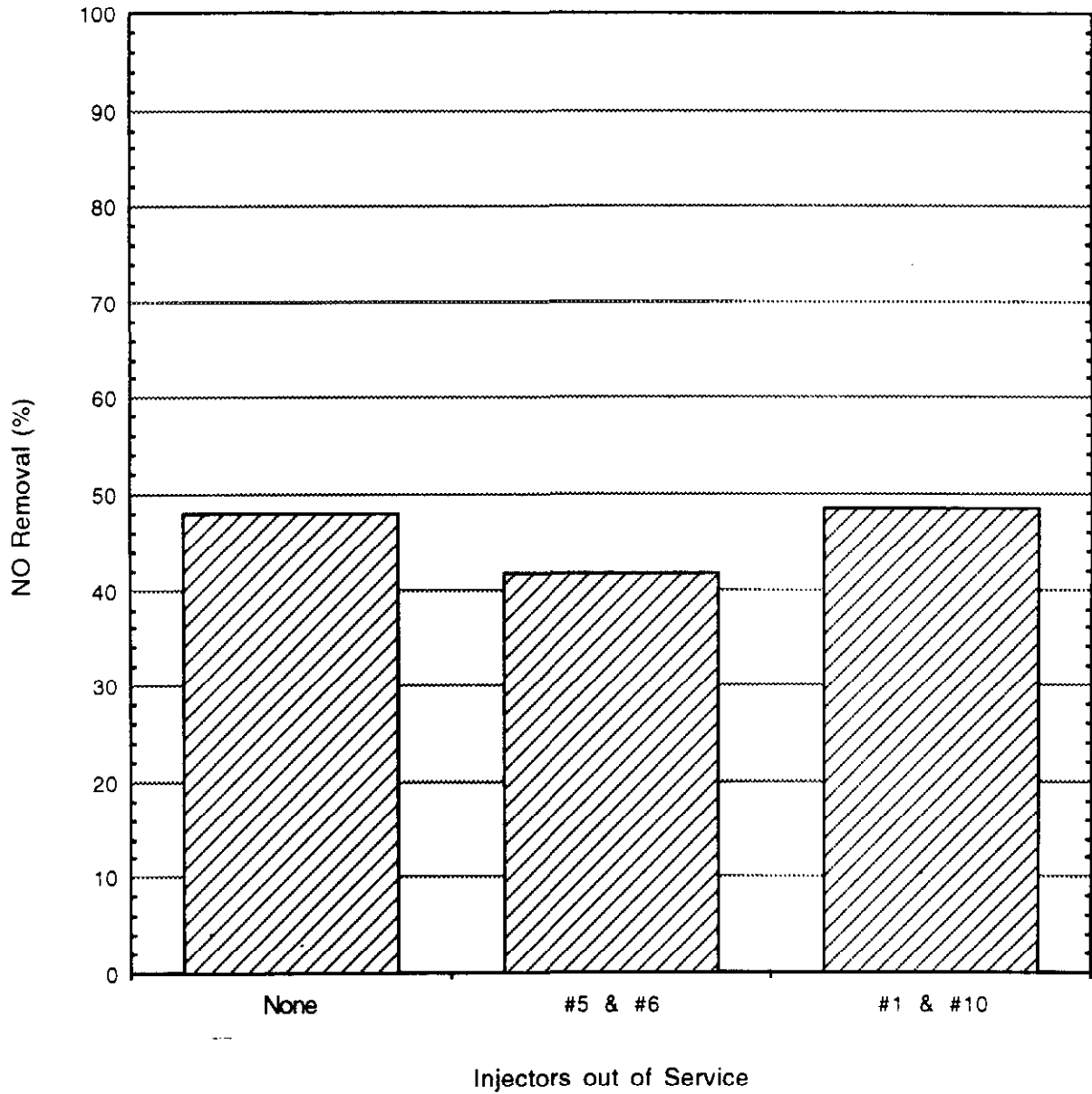
Figure 5-10. Effect of Removing Individual Urea Injectors from Service
(80 MWe, Level 1 Injection, N/NO = 1.0, 8 psig Air, 28 gpm Total Liquid Flow)

FERCo-7034-R229

## 5.4.2 Effect of Boiler Load

The effect of urea injection rate on NO removal and $NH_3$ slip is shown in Figures 5-11a and 5-11b, respectively, for boiler loads of 100, 80 and 60 MWe. For these test results, the total liquid injection rate was 7 gpm, and the mixing air pressure was 8 psig. For all three loads, the NO removal increases as the N/NO ratio is increased. At a nominal N/NO ratio of 1.0, NO removal was 37 percent at full load conditions of 100 MWe. Decreasing the load to 80 MWe increases NO removals to 52 percent, and with a further decrease in load to 60 MWe, the NO removals appeared to decrease slightly, although they essentially remained the same as at 80 MWe. The optimum temperature for this set of injector conditions appears to be in the range of 60 to 80 MWe, as the maximum NO removal occurs in this range. As load is increased, flue gas temperatures increase and NO removal is reduced. This indicates that 100 MWe is on the high side of the temperature window for urea injection.

Another indication of flue gas temperature is the effect of boiler load on ammonia slip as seen in Figure 5-11b. If temperature is on the high side of the optimum range, very little ammonia slip is produced. If the temperature is on the low side, a large amount of ammonia slip is produced. The ammonia slip data again confirm that 100 MWe is on the high side of the temperature window as the low NO removals seen in Figure 5-11a are accompanied by low $NH_3$ emissions. 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. While 10 ppm $NH_3$ in the flue gas may seem to be a large quantity, this amount represents only a one percent conversion of the injected urea to ammonia slip.

Figures 5-11a and 5-11b showed the effect of urea injection rate and boiler load on NO removal and $NH_3$ slip, respectively, for a total liquid injection rate of 7 gpm. Figures 5-12a and 5-12b show similar data for a total liquid injection rate of 28 gpm. Both also include additional data obtained at 110 MWe. The total liquid injection rate was increased by increasing the dilution water flow rate only, as the urea flow must remain constant for a given N/NO ratio. The data show that 110 MWe is on the high side of the temperature window as both the NO removals and $NH_3$ emissions are low. The temperatures at 60 MWe are on the low side as the NO removals are low, but the $NH_3$ emissions high. The major differences between the data shown in Figures 5-11 and 5-12 (i.e., between total liquid injection rates of 7 and 28 gpm) is that the optimum load
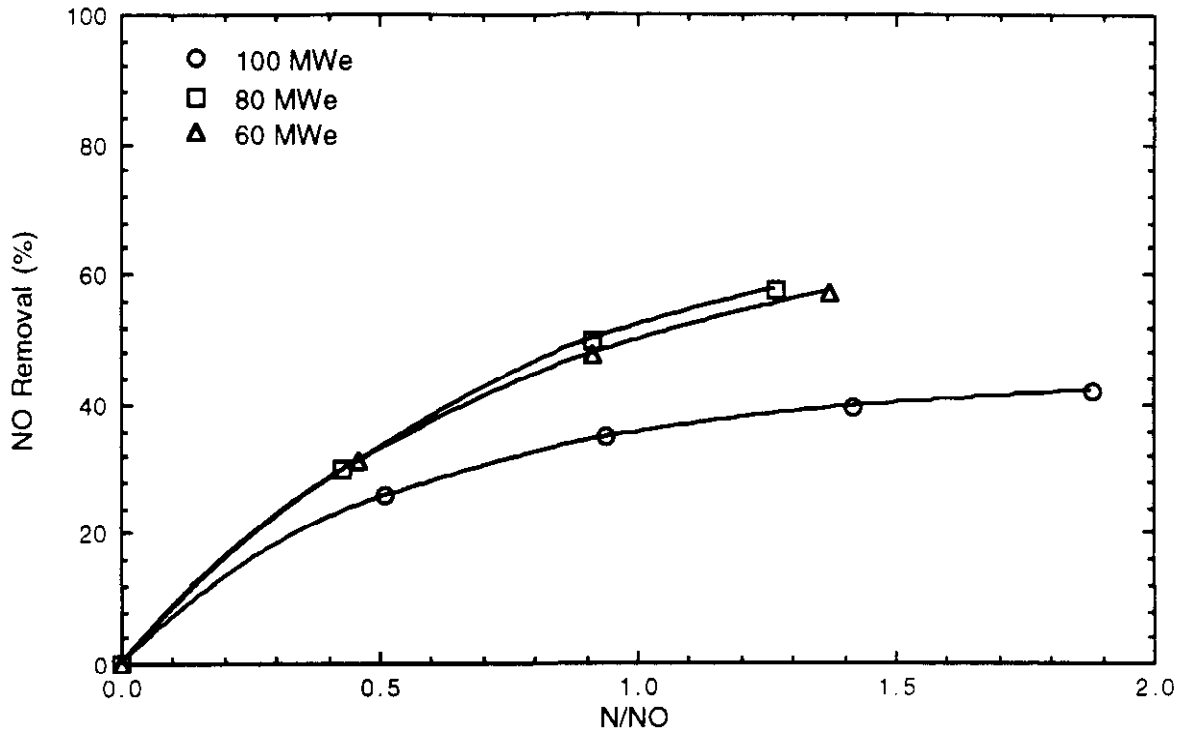
a) NO Removal
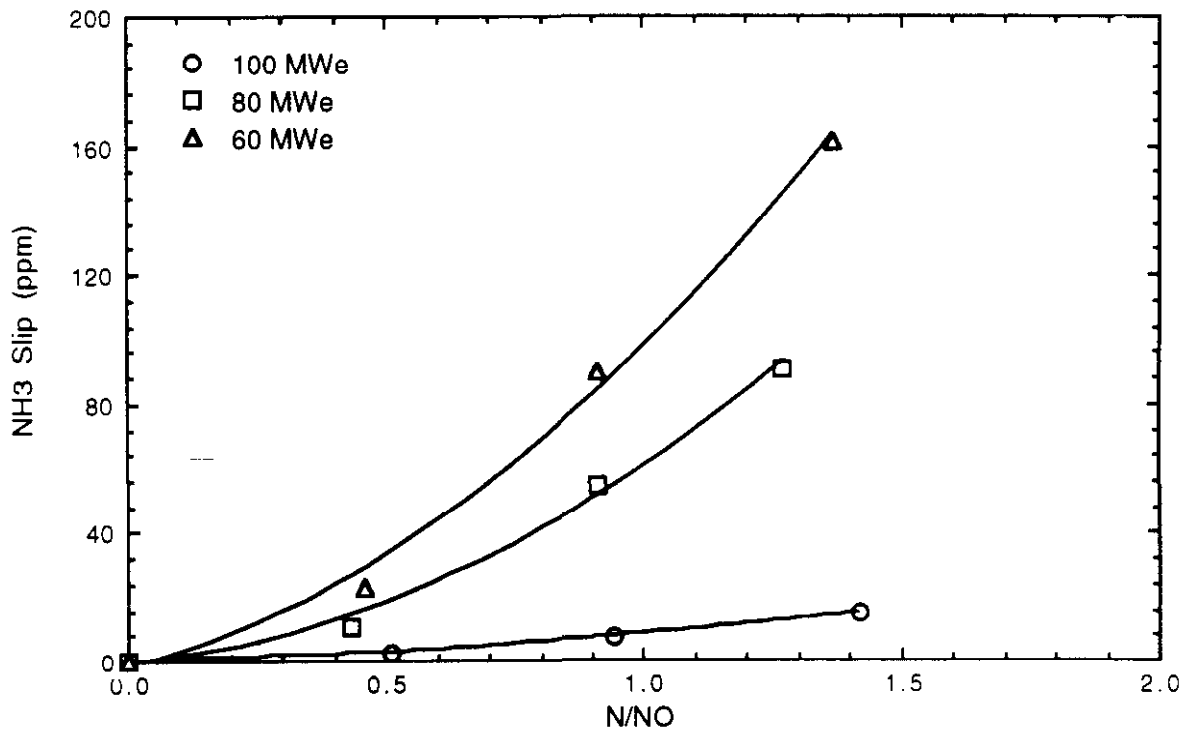


b) NH$_3$ Emissions

Figure 5-11. Effect of Boiler Load on Urea Injection with 7 gpm Total
Liquid Flow (Level 1 Injection, 8 psig Air)

FERCo-7030-R229
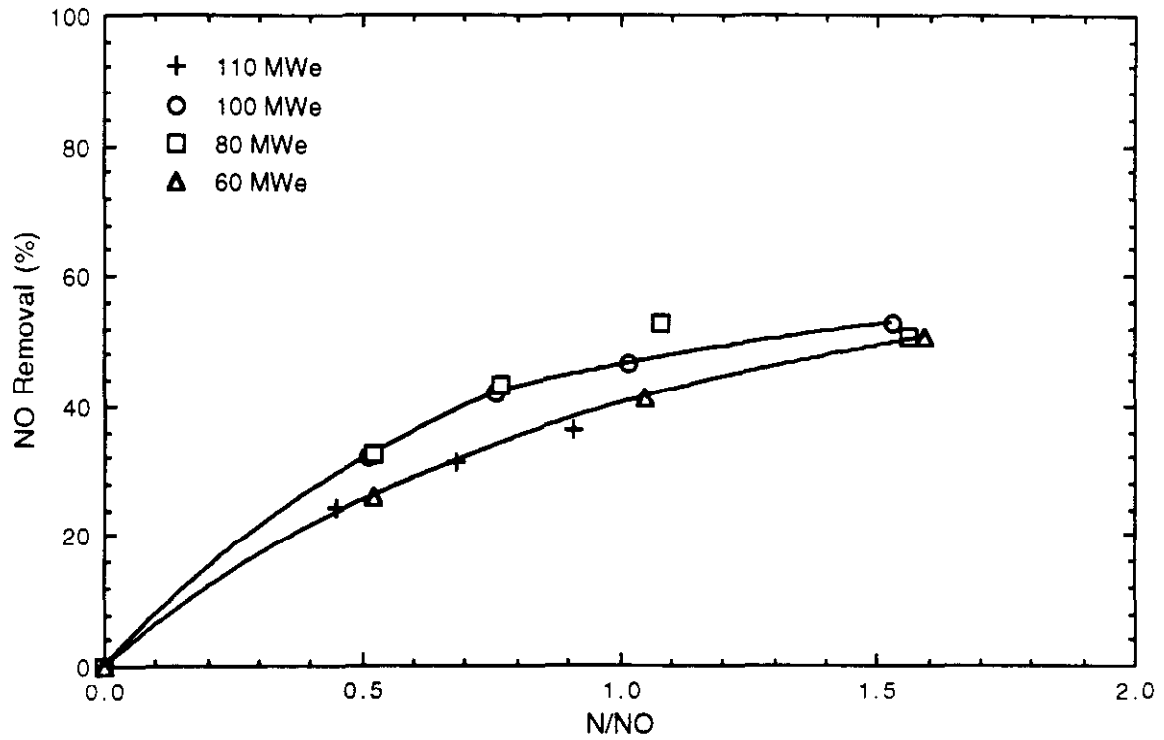
a) NO Removal
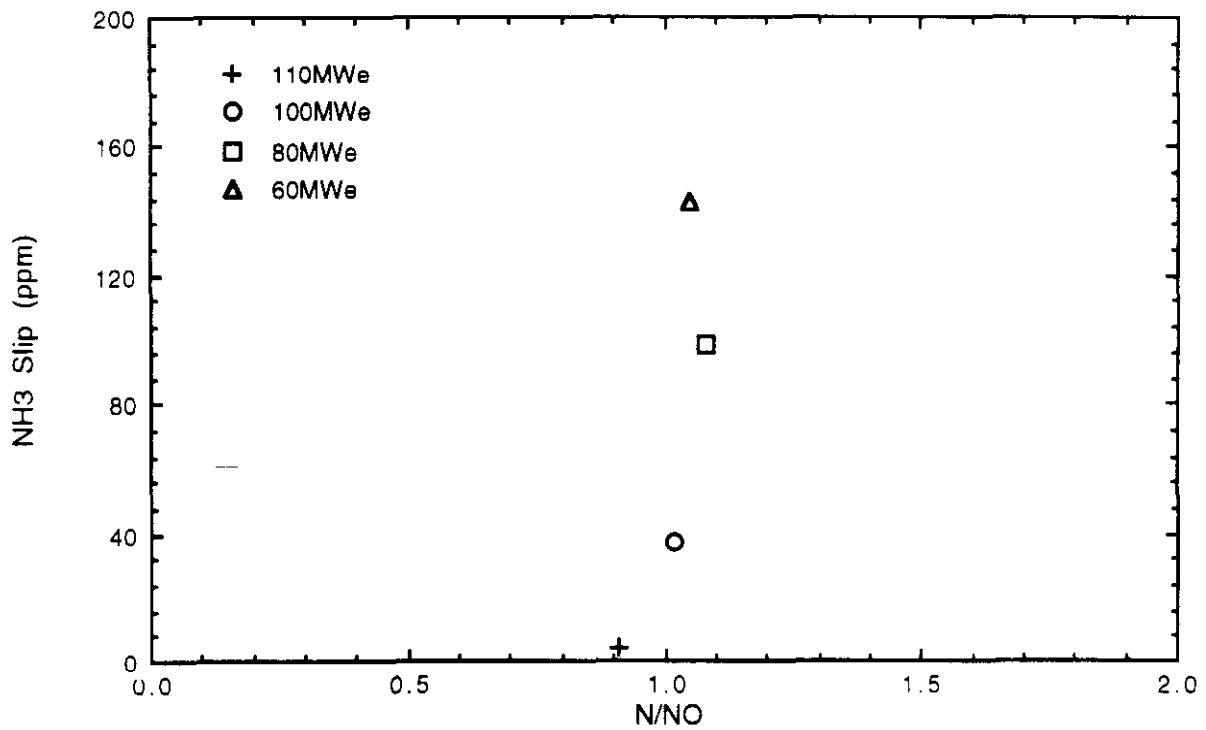


b) NH$_3$ Emissions

Figure 5-12.  Effect of Boiler Load on Urea Injection with 28 gpm Total
Liquid Flow (Level 1 Injection, 8 psig Air)

FERCo-7030-R229

range has shifted upward from 60 to 80 MWe to 80 to 100 MWe. The shift is due to the increased localized cooling effect of the higher total liquid flow rate. This effect will be discussed in further detail in the following section.

Ammonia slip data for the 28 gpm case was collected only during the tests at a nominal N/NO ratio of 1.0, and the results are shown in Figure 5-12b. As seen for the 7 gpm case (Figure 5-11b), decreasing boiler load (temperature) results in increasing ammonia emissions. The values range from 4 ppm at 110 MWe to 143 ppm at 60 MWe.

The effect of boiler load on the performance of urea injection reinforces the importance of temperature on both NO removal and $NH_3$ emissions. The differences in the results seen at 7 and 28 gpm show that total liquid flow rate also has an important effect on temperature. The next section will show in more detail how the dilution water flow can be used to optimize performance at a given boiler load.

### 5.4.3 Effect of Total Liquid Flow Rate

The results discussed in the previous section indicated that varying the amount of dilution water flow can be used to optimize the urea injection performance. To investigate this effect further, 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 Figures 5-13, 5-14 and 5-15 for boiler loads of 100, 80 and 60 MWe, respectively.

The data show that at 100 MWe, increasing the total liquid injection flow rate from 7 to 28 gpm increases the level of NO reduction (Figure 5-13a) as well as $NH_3$ emissions (Figure 5-13b). Recall from the discussion in Section 5.2 that the local cooling effect of the injected liquid solution and mixing air is nominally 120°F for a liquid flow rate of 28 gpm and air flow rate of nominally 3900 scfm (8 psig). Of the 120°F cooling effect, 30°F is attributable to the mixing air and 90°F to the injected liquid. 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
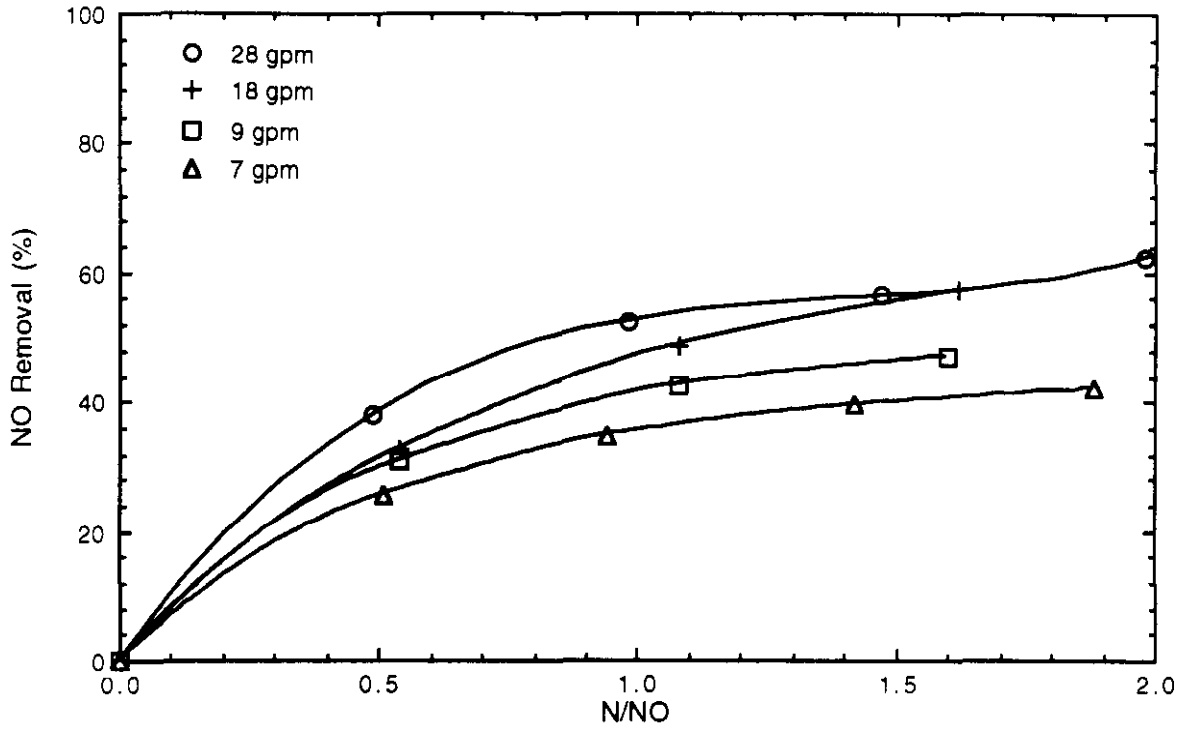
a) NO Removal
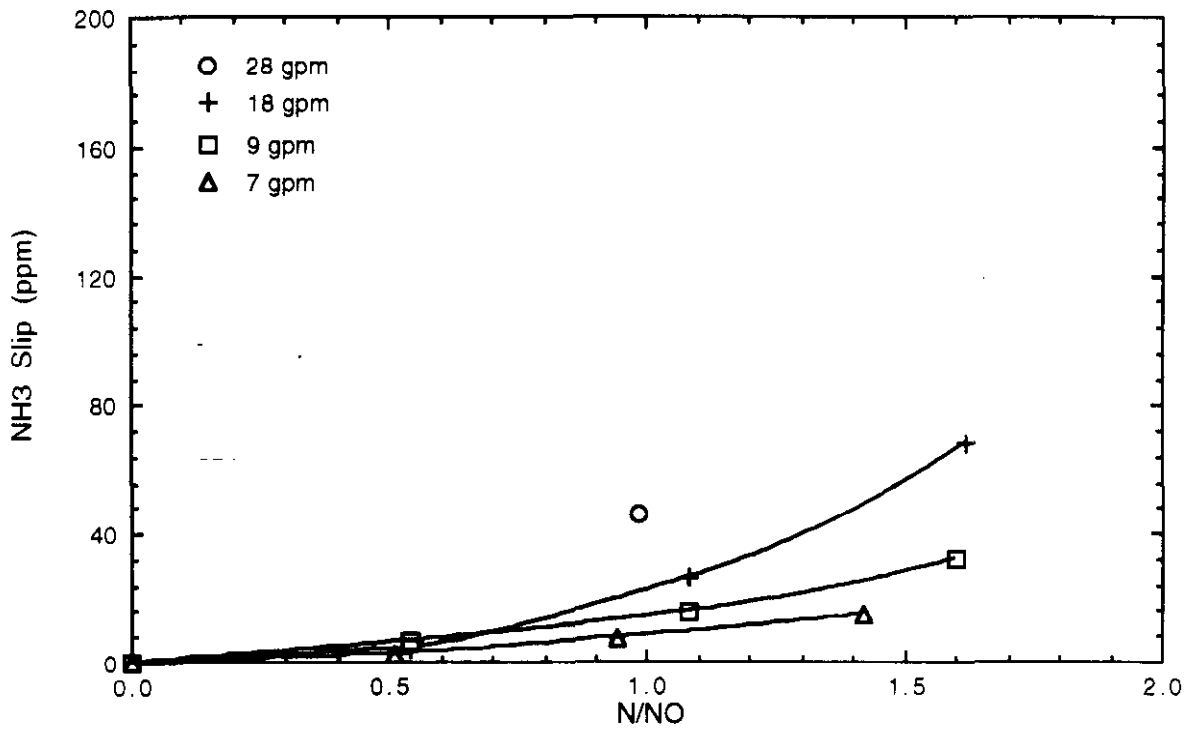


b) NH₃ Emissions

Figure 5-13. Effect of Total Liquid Flowrate on Urea Injection at 100 MWe
(Level 1 Injection, 8 psig Air)

5-20
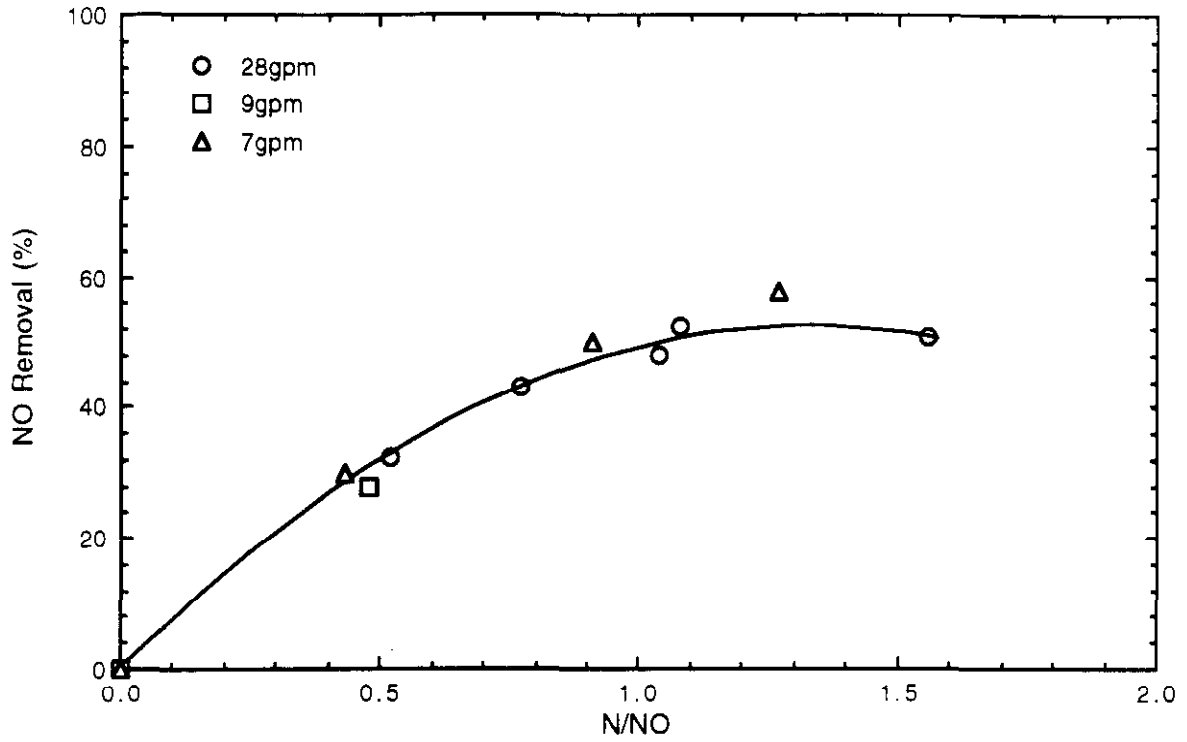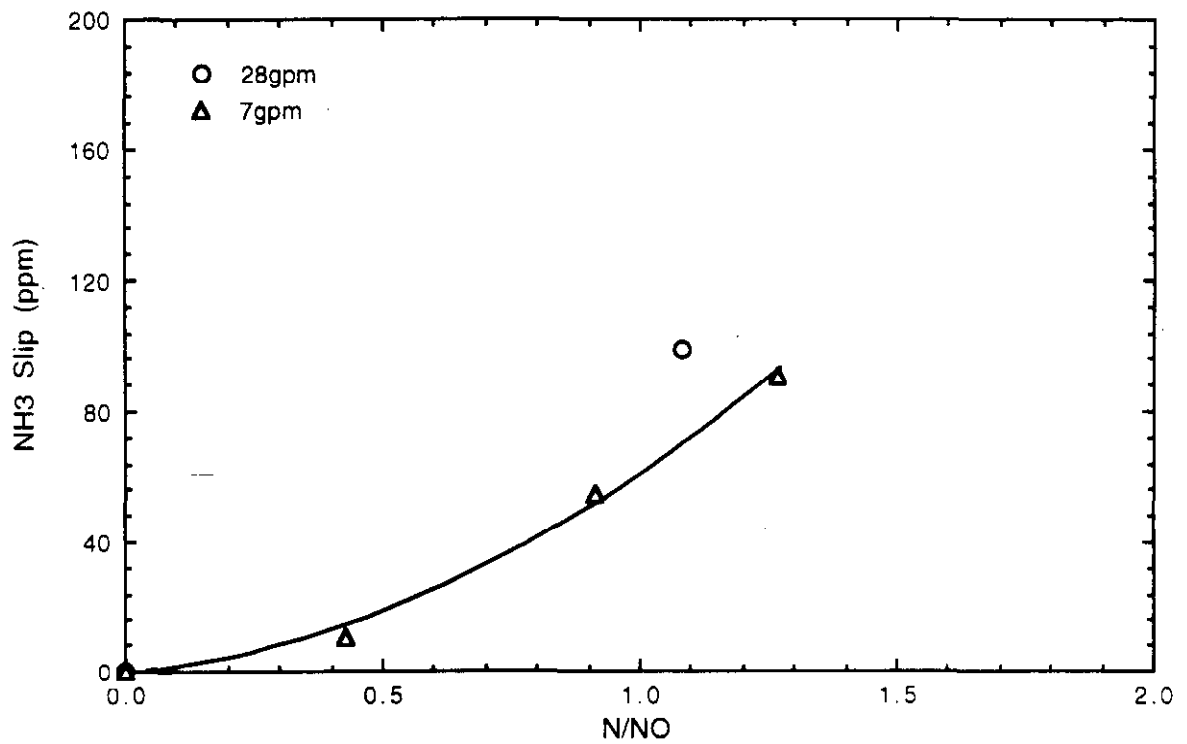
a) NO Removal



b) NH₃ Emissions

Figure 5-14.  Effect of Total Liquid Flow Rate on Urea Injection at 80 MWe
(Level 1 Injection, 8 psig Air)

5-21

FERCo-7030-R229
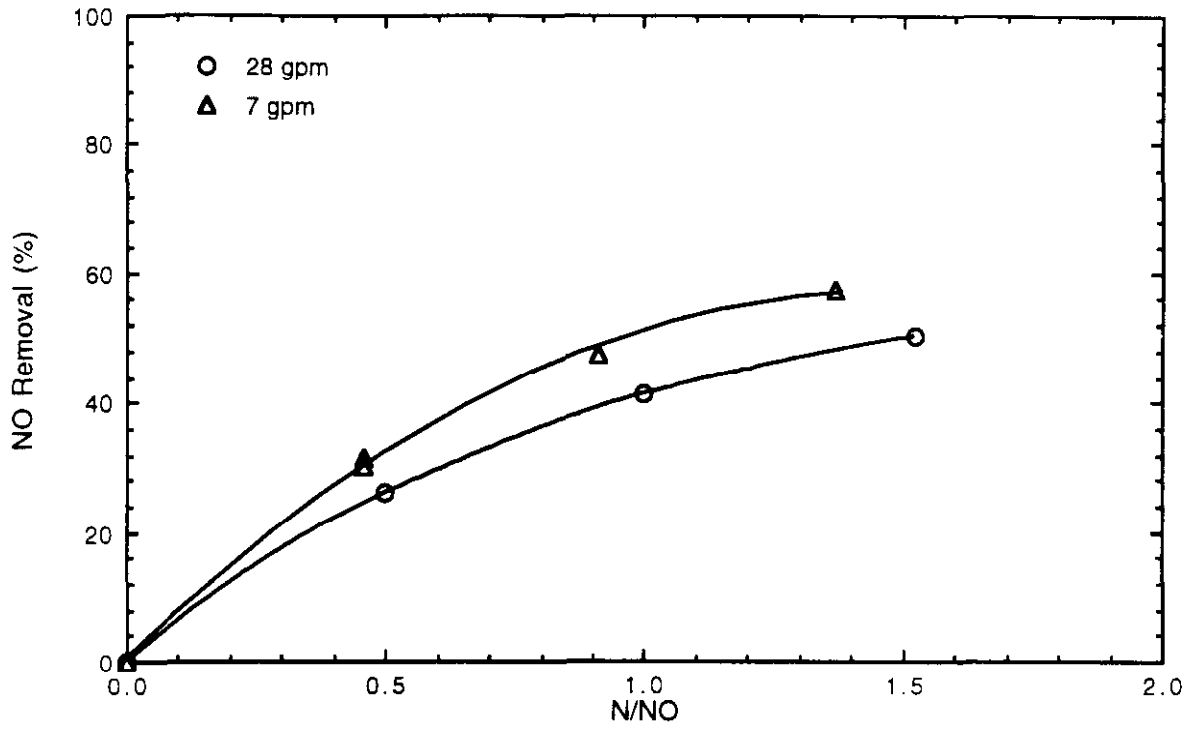
a) NO Removal
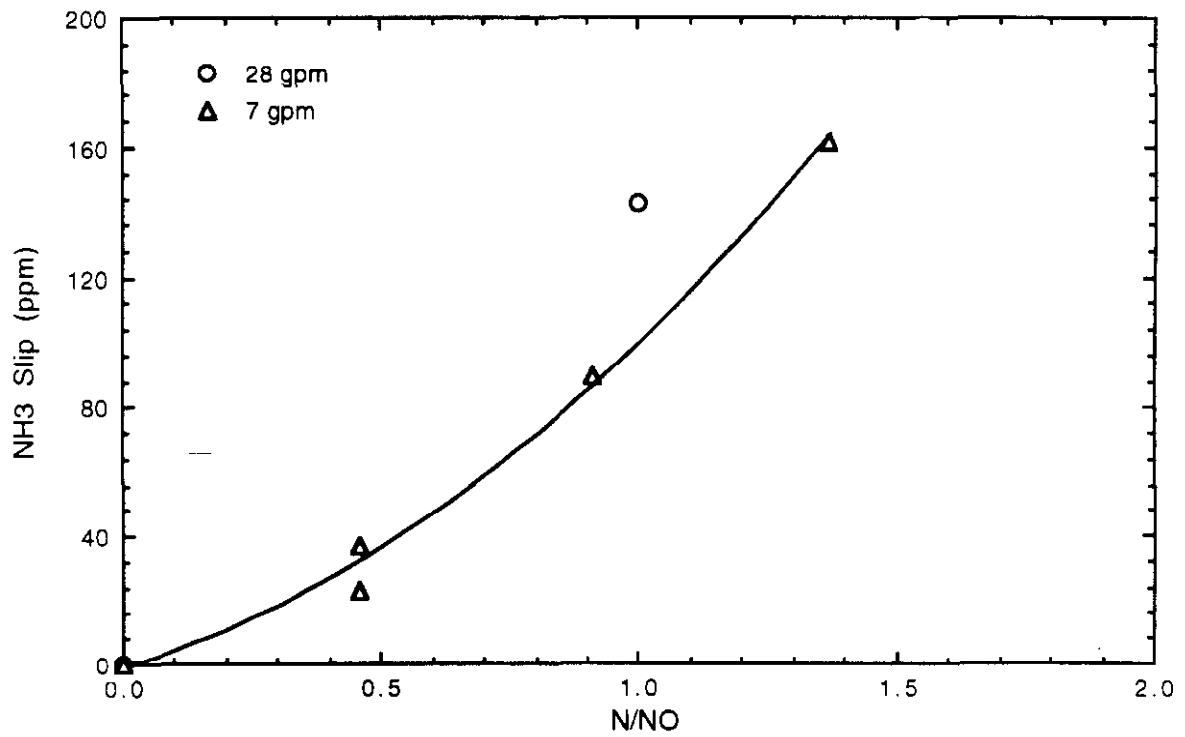


b) NH₃ Emissions

Figure 5-15. Effect of Liquid Flow Rate on Urea Injection at 60 MWe
(Level 1 Injection, 8 psig Air)

FERCo-7030-R229

operational standpoint, using a liquid flow of 28 gpm is not a practical operating condition. As will be discussed later, these high liquid flow rates had a major impact on steam attemperation rates and the ability of the boiler to maintain steam temperatures. Operating at below-design steam temperatures reduces boiler efficiency, and the latent heat associated with vaporizing the 28 gpm liquid flow represents a boiler efficiency loss on the order 1.5 percent.

The effect of dilution water flow was also investigated at boiler loads of 80 and 60 MWe. The results of varying dilution water flow at 80 MWe is shown in Figure 5-14. At 80 MWe, varying the total liquid flow rate from 7 to 28 gpm had essentially no effect on the NO removals (Figure 5-14a). This would suggest that at 80 MWe, the Level 1 injectors are mixing the urea solution with the combustion products at near the optimum, or perhaps slightly on the high side of the temperature window. Thus, with changes in temperature due to the additional dilution water flow, the process is still operating near the peak in the temperature window with little net effect on the NO removal. While only one $NH_3$ data point is available at the 28 gpm flow (Figure 5-14b), it appears that the trend is as that seen at 100 MWe, namely increasing the total liquid flow rate results in increased $NH_3$ slip.

At a boiler load of 60 MWe, the effect of dilution water flow (Figure 5-15) reverses from that seen at 100 MWe (Figure 5-13). As shown in Figure 5-15a, increasing the solution flow rate at this lower boiler load results in a decrease in NO removals. This indicates that at 60 MWe, injection was on the low side of the temperature window and that increasing the solution flow rate further reduces temperature, thereby decreasing NO removals. The single $NH_3$ slip value at the 28 gpm flow rate shown in Figure 5-15b again indicates the trend of increasing $NH_3$ slip with increasing dilution water flow rates.

### 5.4.4   Effect of Mixing Air Flow Rate

Another parameter that can affect the performance of urea injection is the mixing air flow rate. At a boiler load of 100 MWe, the effect of mixing air was assessed over a mixing air pressure range of 1.5 to 12 psig. At 12 psig, pressure is sufficient (at the 5200 foot altitude of Denver, Colorado) to generate sonic gas velocities at the exit of the injection nozzle. Further pressure increase would not result in increases in nozzle velocity, so pressures above 12 psig were not examined. With a constant air orifice size of 1.5 inches on the injectors at Level 1, the change

in pressure from 1.5 to 12 psig represents a change in mixing air flow rate from nominally 1700 to 4800 scfm. The effect on NO removal and $NH_3$ emissions is shown in Figure 5-16. For these test conditions, reducing the mixing air flow rate from 4800 to 1700 scfm decreased the NO reduction from 58 to 50 percent at a nominal N/NO ratio of 1.5. The decrease in mixing air flow rate had a larger effect on the $NH_3$ emissions. At mixing air pressures of 8 to 12 psig (3900 to 4800 scfm), $NH_3$ emissions were nominally 10 ppm. However, when the mixing air pressure was reduced to 1.5 psig, the $NH_3$ emissions increased to 50 ppm. It should be noted that the $NH_3$ concentrations shown in Figure 5-16 were from the continuous $NH_3$ analyzer during the test period when it was not possible to use the probe heater. Thus, the $NH_3$ values shown in Figure 5-16 may be low relative to a composite sample across the duct using the wet chemical technique, although it is believed that the relative changes shown are accurate.

### 5.4.5   Nitrous Oxide ($N_2O$) Emissions

$N_2O$ emissions were also monitored during the urea injection tests. While not a regulated species, there is interest in $N_2O$ emissions due to impacts on stratospheric ozone chemistry and potential contributions to the greenhouse effect. Prior pilot-scale and full-scale studies have shown $N_2O$ to be a product of the urea injection process[6,7]. As discussed in section 4.1, $N_2O$ is currently thought to form through a mechanism of the form

$$NH_2CONH_2 \quad \text{--------}\rightarrow \quad NH_3 + HNCO \qquad (1)$$

$$HNCO + OH \quad \text{--------}\rightarrow \quad NCO + H_2O \qquad (2)$$

$$NCO + NO \quad \text{--------}\rightarrow \quad N_2O + CO \qquad (3)$$
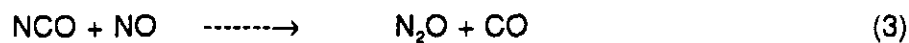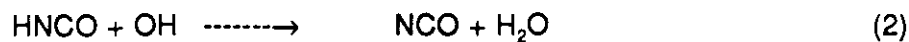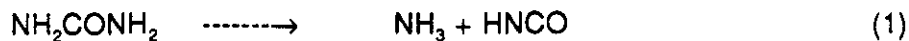
Whether the $N_2O$ remains and is emitted from the stack, or is reduced in the flue gas stream depends primarily on the following destruction reaction mechanism:

$$N_2O + H \quad \text{--------}\rightarrow \quad N_2 + OH \qquad (4)$$

$$N_2O + OH- \quad \text{--------}\rightarrow \quad N_2 + HO_2 \qquad (5)$$

$$N_2O + M \quad \text{--------}\rightarrow \quad N_2 + \ldots \qquad (6)$$
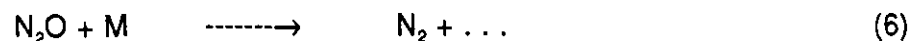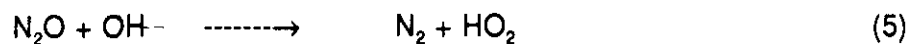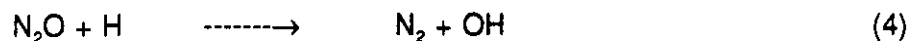
In reaction (6), "M" represents one of any number of "general molecules" which can react with $N_2O$ and reduce it to $N_2$. The $N_2O$ emissions with urea injection at Level 1 are shown in Figure 5-17. In the figure, the $N_2O$ levels are normalized by the amount of NO reduced. This can also
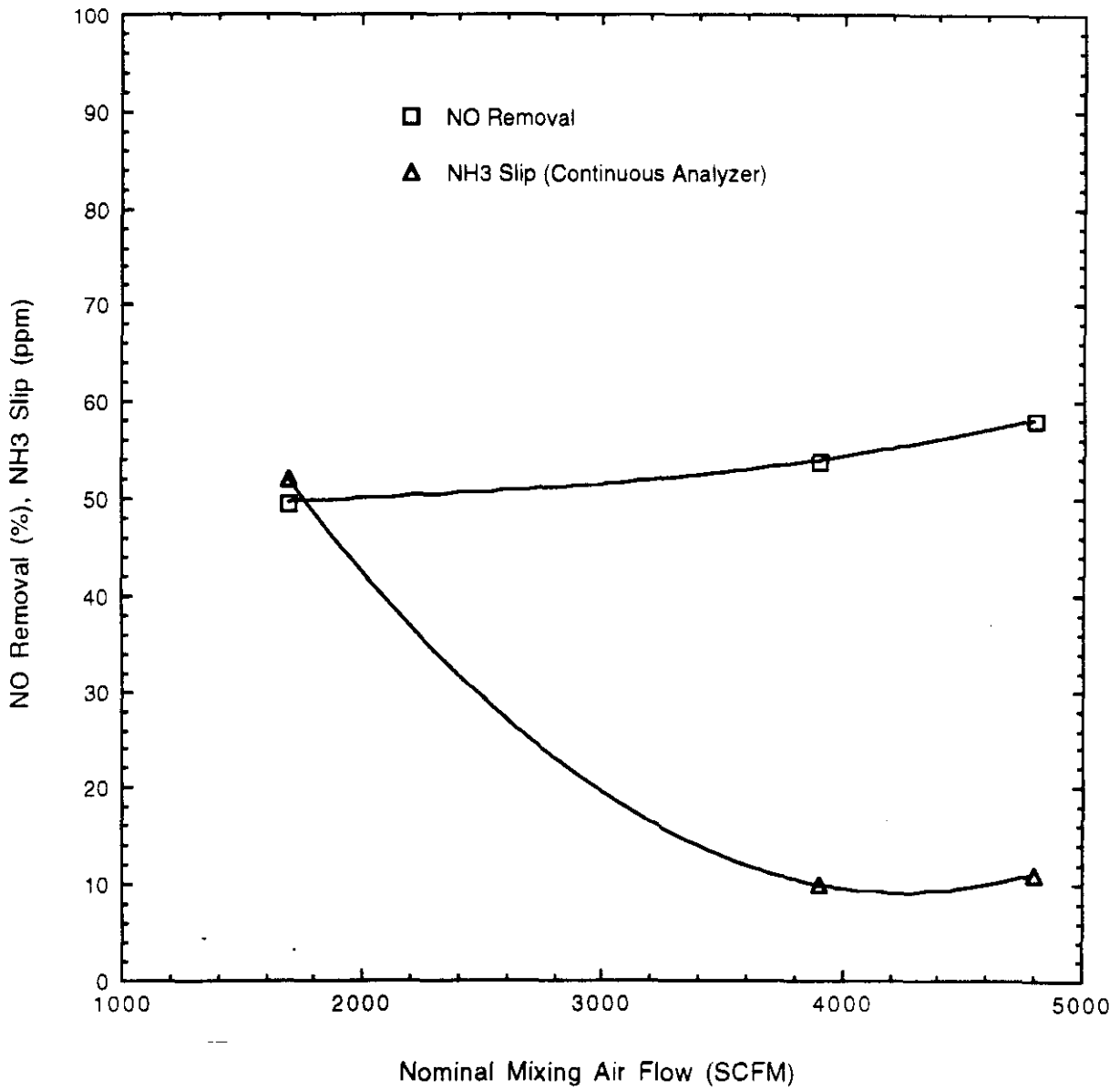
Figure 5-16. Effect of Mixing Air Flow Rate on Urea Injection
(100 MWe, Level 1 Injection, N/NO = 1.5, 28 gpm Total Liquid Flow)

FERCo-7034-R229
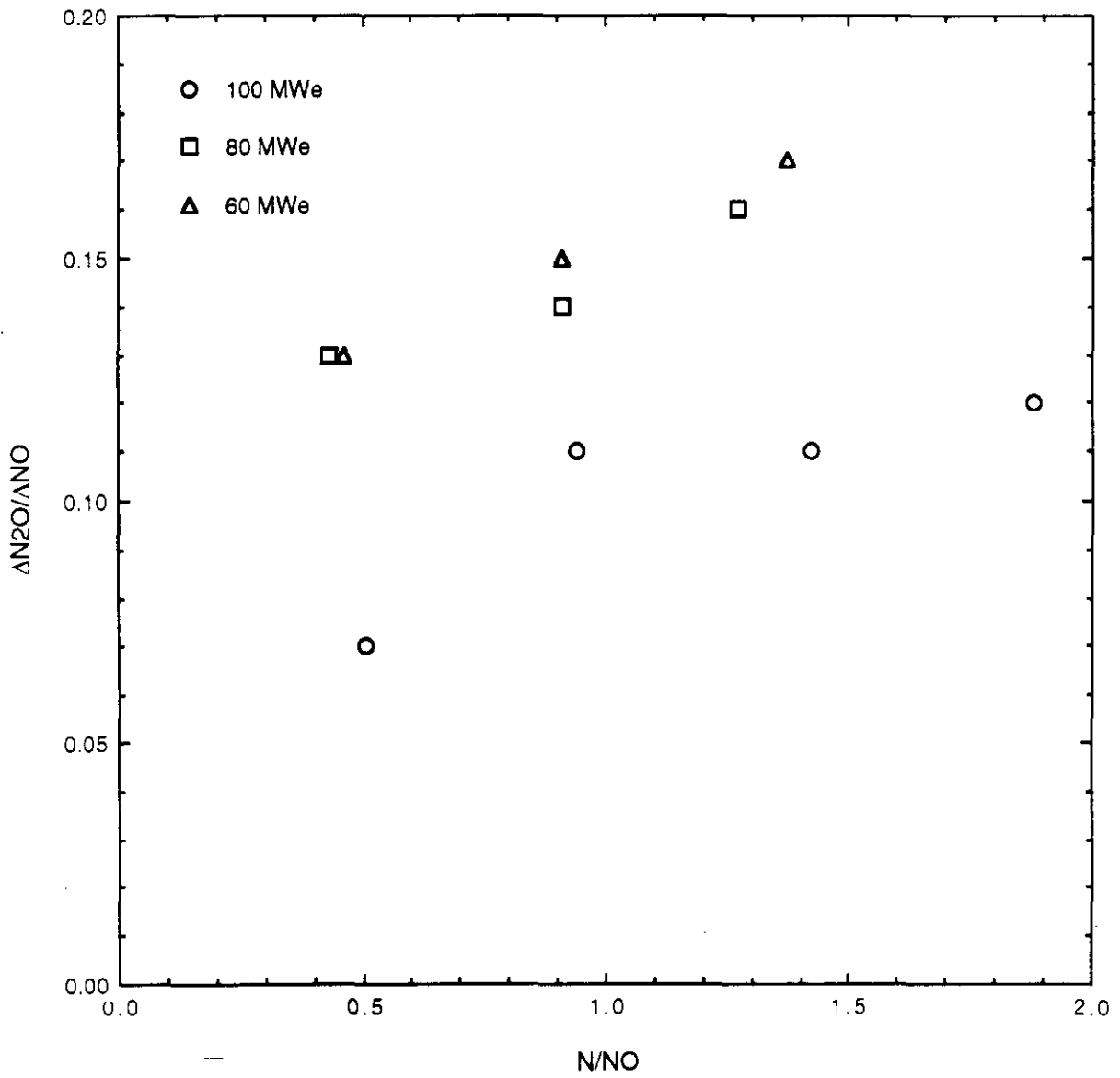
Figure 5-17. N$_2$O Emissions with Urea Injection
(Level 1 Injection, 8 psig Air, 7 gpm Total Liquid Flow)

be interpreted as the fraction of NO that is converted to $N_2O$. As seen in Figure 5-17, the conversion ranged from 7 to 17 percent. These levels of conversion are consistent with previous studies[7]. Two other observations are noteworthy in Figure 5-17. First, the $N_2O$ levels are lower at full load conditions of 100 MWe than at reduced loads of 80 and 60 MWe. This is consistent with the results seen in pilot-scale studies[7] where the temperature for maximum $N_2O$ conversion was shown to roughly correspond to the temperature for maximum NO removal. Recall that higher NO removals were seen at 60 and 80 MWe than at 100 MWe (Figure 5-11a). The second observation is that there appears to be a trend of increasing $N_2O$ with increasing urea injection rates (N/NO ratio) at each load. This differs somewhat from other full-scale SNCR demonstrations or pilot-scale studies[6,7]. In these other studies, $N_2O$ emissions (on the same normalized basis as in Figure 5-17) were seen to be relatively independent of the urea injection rate. At the present, no explanation can be offered for the increasing $N_2O$ conversion with increasing N/NO ratio shown in Figure 5-17.

## 5.4.6  CO Emissions

There is the potential for increases in CO emissions with application of SNCR to a utility boiler. This increase can occur due to two mechanisms. First, if urea is used as the SNCR chemical, the carbon present in the urea can contribute to the CO levels. This occurs when the CO released from the urea decomposition reaction is not oxidized to $CO_2$. Secondly, the amount of CO generated from the combustion process that is normally oxidized to $CO_2$ in the area of urea injection may be reduced. This oxidation process occurs primarily through the reaction

$$CO + OH \quad \text{--------} \rightarrow \quad CO_2 + H \qquad (7)$$
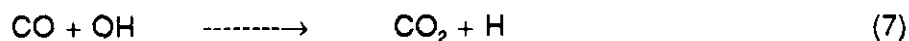
With either urea or ammonia injection, OH is utilized in the SNCR reaction process (recall Figure 4-3). The SNCR chemistry can then compete with CO for OH species, resulting in an inhibition in the oxidation of the CO from the combustion process.

The increases in CO emissions that were measured at the economizer exit during the urea injection tests are summarized in Figure 5-18. The open symbols shown in Figure 5-18 are the recorded increases in CO as measured with the continuous analyzer. Nondispersive infrared (NDIR) CO analyzers have an interference with $N_2O$ and will measure a higher CO value if $N_2O$ is present. The interferences for the Horiba PIR 2000 CO analyzer were characterized in the
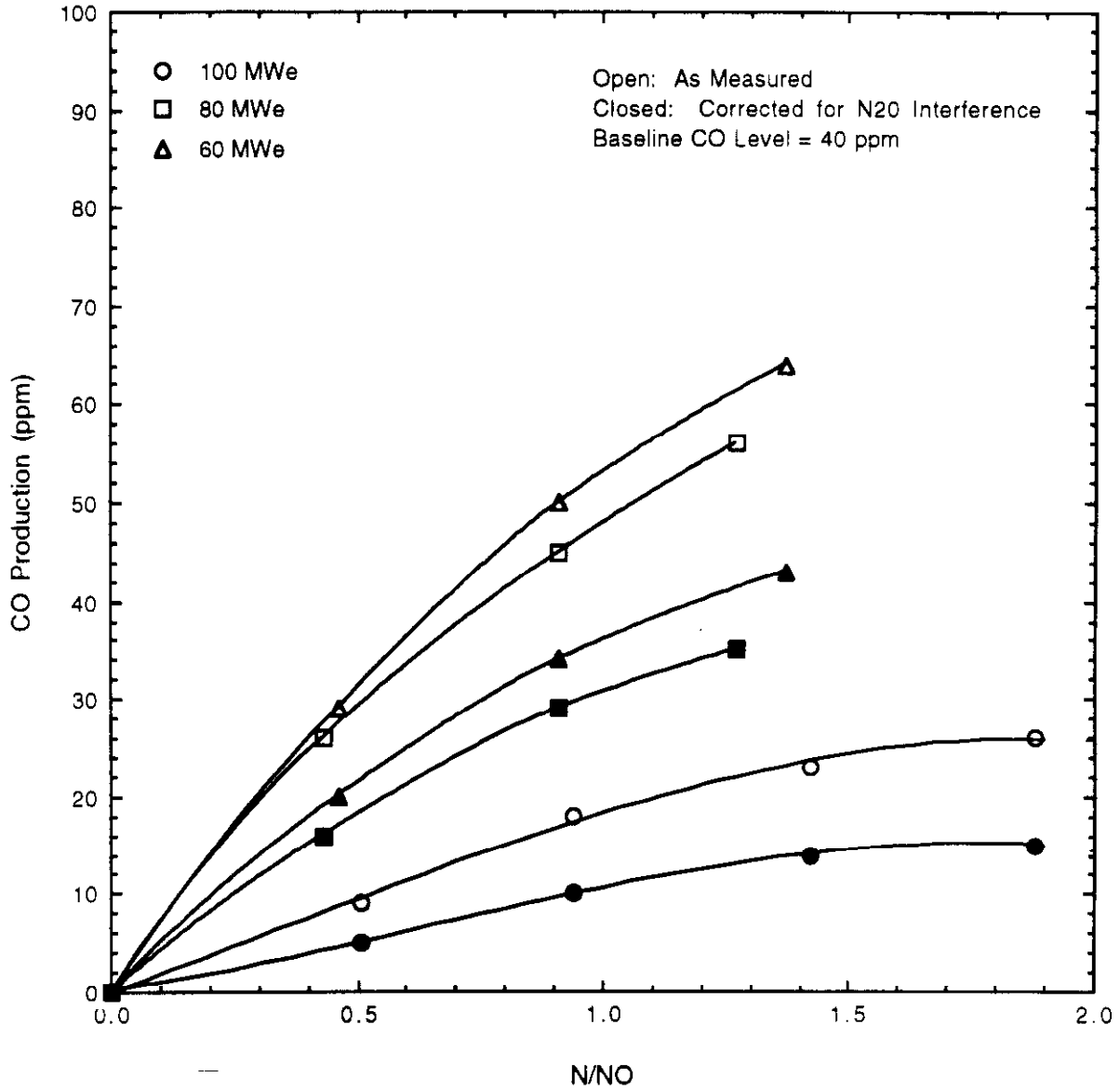
Figure 5-18.  CO Production with Urea Injection
(Level 1 Injection, 8 psig Air, 7 gpm Total Liquid Flow)

FERCo-7034-R229

Fossil Energy Research Corp. laboratory and are summarized in Table 5-4. The closed symbols in Figure 5-18 represent the CO production data corrected for the $N_2O$ interference. The data show that CO emissions increased with increasing urea injection rates (N/NO ratio), and the increases in CO were higher at the reduced boiler loads (60 and 80 MWe). It is impossible to conclude whether the CO increases are due primarily to the carbon in the urea, or inhibition of the normal CO oxidation reaction from this data alone. At a urea injection rate corresponding to a nominal N/NO of 1.0, the carbon in the urea could theoretically contribute to an increase in CO of about 425 ppm. The maximum CO increase at a ratio of 1.0 was only 32 ppm. As will be discussed in Section 5.5.4, CO production (corrected for the $N_2O$ interference) increased nearly linearly up to 12 ppm with $NH_4OH$ injection as nominal N/NO ratios were increased from 0.5 to 2.0. This increase was also shown to be independent of load. For $NH_4OH$, the increase can only be attributed to inhibition of the normal CO oxidation reaction. Thus, nearly all of the full load increase seen in Figure 5-18 (15 ppm at a N/NO ratio of 2.0) can also be attributed to inhibition of the oxidation of the boiler CO. While the full load CO increase is likely due to inhibition of boiler CO oxidation, it explains only approximately 25 percent of the CO increase at lower loads. The increase in CO at these lower loads (i.e., lower flue gas temperatures) are likely caused by CO formation from the urea. Thus, it would appear that the increase in CO by urea injection is due to both the carbon injected as part of the urea and to inhibition of the normal oxidation of the boiler CO. After accounting for the $N_2O$ interference on the CO analyzer, this increase is, at most, of the order of 42 ppm, which is less than 5 percent of the carbon contained in the urea solution.

Table 5-4

LABORATORY TEST RESULTS:
$N_2O$ INTERFERENCES ON A HORIBA PIR 2000 CO ANALYZER

| $N_2O$ (ppm) | Indicated CO Reading (ppm) |
|---|---|
| 3 | 1 |
| 39 | 10 |
| 90 | 21 |
| 132 | 30 |
| 170 | 39 |

## 5.5    NH$_4$OH INJECTION AT LEVEL 1

The data presented in the previous sections show that urea injection provides reasonable levels of NO reduction at full load. However, at reduced loads, only small NO reductions were possible while maintaining reasonable levels of ammonia slip. For this reason, it was decided to perform a short term test with aqueous ammonia to determine if significant increases in NO reduction performance could be achieved.

The NH$_4$OH solution (29.4 weight percent as NH$_3$) was stored in a tanker truck and transferred to the suction side of the SNCR injection pump using a small transfer pump. Since there was only provision for two days of testing, parametric variations were limited to 1) boiler load, 2) N/NO ratio, and 3) a cursory investigation of the effect of total liquid flow rate. All tests were conducted with the level 1 set of injectors with the injection air pressure fixed at 8 psig.

### 5.5.1    Effect of Boiler Load

The effect of the N/NO ratio at boiler loads of 60, 80 and 100 MWe is shown in Figure 5-19 for NH$_4$OH injection with a total liquid injection rate of 7 gpm. The results with aqueous ammonia injection are somewhat different than with urea. With NH$_4$OH injection, NO removals increased as the boiler load decreased (recall that with urea injection NO removals appeared to peak at a boiler load between 60 and 80 MWe). This would indicate that the overall temperature window is lower for NH$_4$OH than for urea. This effect has been reported in previous studies[2,3]. It is obvious that the flue gas temperatures at both 80 and 100 MWe are on the high side of the temperature window, as NO removal is low and NH$_3$ slip essentially zero. At 60 MWe, NO reduction is greatly increased, but NH$_3$ emissions have also increased substantially. It appears that the optimum temperature range for NH$_4$OH injection is approached as load is reduced from 80 to 60 MWe, but further testing would be required to actually define the optimum point. It does appear that NH$_4$OH injection is more effective than urea at 60 MWe. With urea, a NO$_x$ reduction of approximately 14 percent could be achieved with NH$_3$ slip limited to 10 ppm. With NH$_4$OH, a NO$_x$ reduction of approximately 25 percent could be achieved at an equivalent slip level.

The factors leading to the lower temperature window with aqueous ammonia compared to urea are not completely understood, although both chemical and physical factors could contribute to
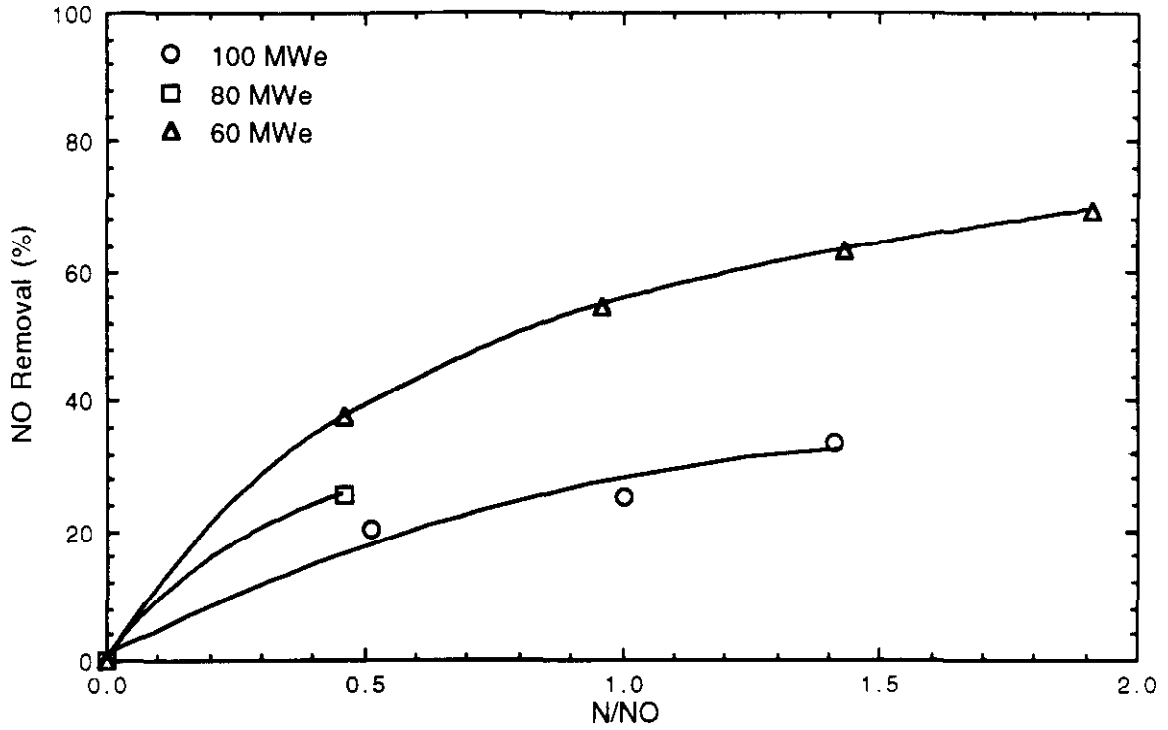
a) NO Removal
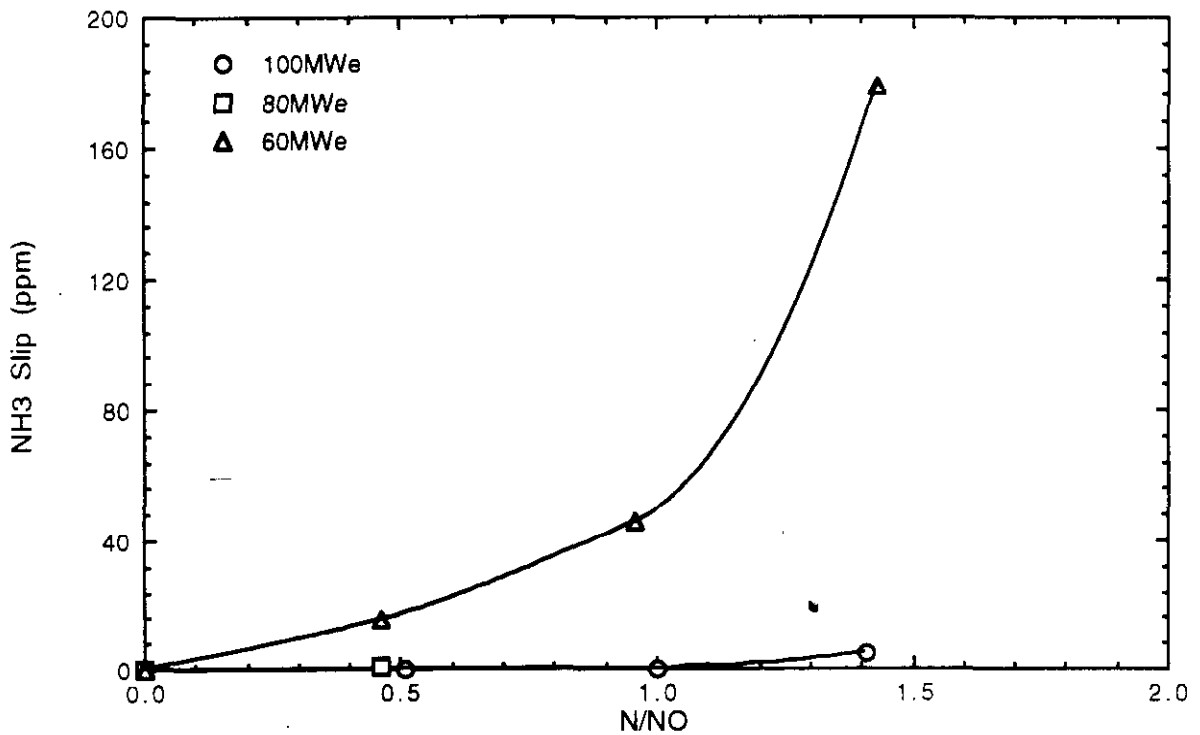


b) NH$_3$ Emissions

Figure 5-19. Effect of Boiler Load on NH$_4$OH Injection
(Level 1 Injection, 8 psig Air, 7 gpm Total Liquid Flow)

5-31

FERCo-7030-R229

the difference. As discussed previously, chemical decomposition of urea is thought to yield $NH_3$ and HNCO. The chemical paths for the reactions between HNCO and NO could contribute to the higher temperature window for urea. From a physical standpoint, the aqueous ammonia and urea solutions are thought to vaporize and decompose differently. Upon injection into the furnace, an $NH_4OH$ droplet will release $NH_3$ very rapidly throughout the vaporization process. On the other hand, the urea solution droplet will likely have to vaporize until the solution is nearly saturated before substantial decomposition of the urea occurs, then releasing the reacting nitrogen species to the gas phase. This would in effect allow the urea to be transported to a cooler region before the decomposition occurs, giving the appearance that the reactions are occurring at higher temperatures. Which of these effects results in the different temperature windows is not known.

### 5.5.2  Effect of Total Liquid Flow Rate

Since it appeared that at 100 MWe the level 1 injectors were on the high side of the $NH_4OH$ temperature window, a brief series of tests was performed at an increased dilution water flow rate. The solution flow rate was increased from 7 to 18 gpm. The effect on NO removal and $NH_3$ emissions is shown in Figure 5-20a and 5-20b, respectively. As can be seen in Figure 5-20a, increasing the dilution water flow rate increased NO reduction from 23 to 30 percent at a nominal N/NO ratio of 1.0. Very little effect was seen on the $NH_3$ emissions (Figure 5-20b), with $NH_3$ emissions remaining under 10 ppm at N/NO ratios up to 1.5. This would suggest that even with the flow rate increase, $NH_4OH$ injection through the level 1 set of injectors was still substantially on the high side of the temperature window.

Due to time constraints, it was not possible to perform $NH_4OH$ injection tests at the upper set of injectors (Level 2), which inject into a cooler region of the furnace. If $NH_4OH$ injection is incorporated into the retrofit test program, a more complete characterization will be conducted.

### 5.5.3  Nitrous Oxide ($N_2O$) Emissions

$N_2O$ emissions were also measured during the $NH_4OH$ injection tests. The results of these tests are shown in Figure 5-21. As with the previous discussion the results with urea injection, the $N_2O$ emissions are shown as a fraction of the NO reduced. Consistent with previous studies, the $N_2O$ emissions with $NH_4OH$ injection are lower than those with urea injection. For the tests conducted during this program, the $N_2O$ levels were less than 3 percent of the NO reduced. The lower $N_2O$
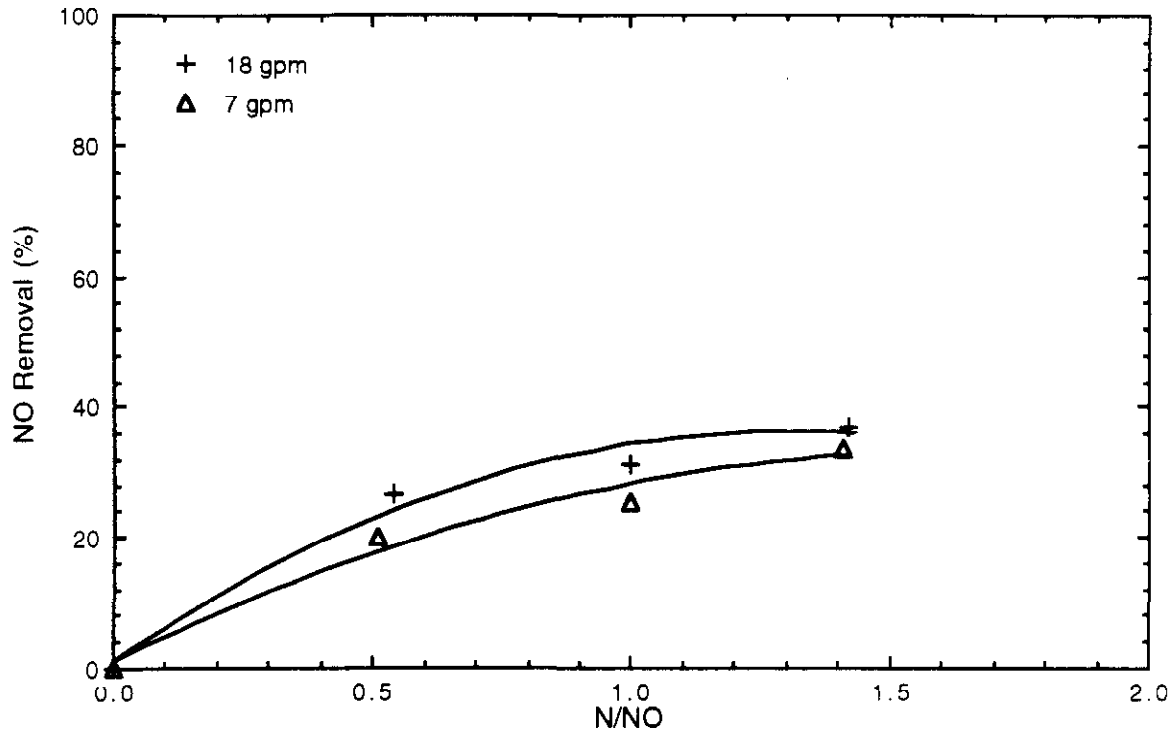
a) NO Removal
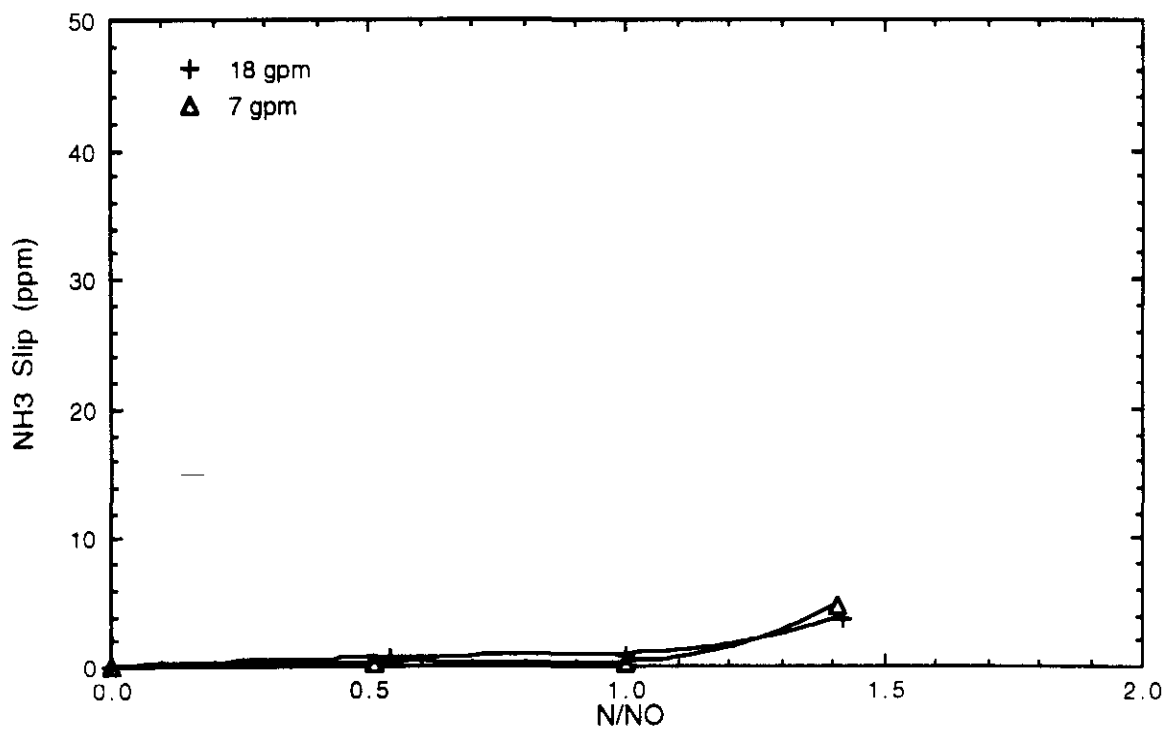


b) NH₃ Emissions

Figure 5-20.  Effect of Total Liquid Flow Rate on NH₄OH Injection
(100 MWe, Level 1 Injection, 8 psig Air)

5-33

FERCo-7030-R229
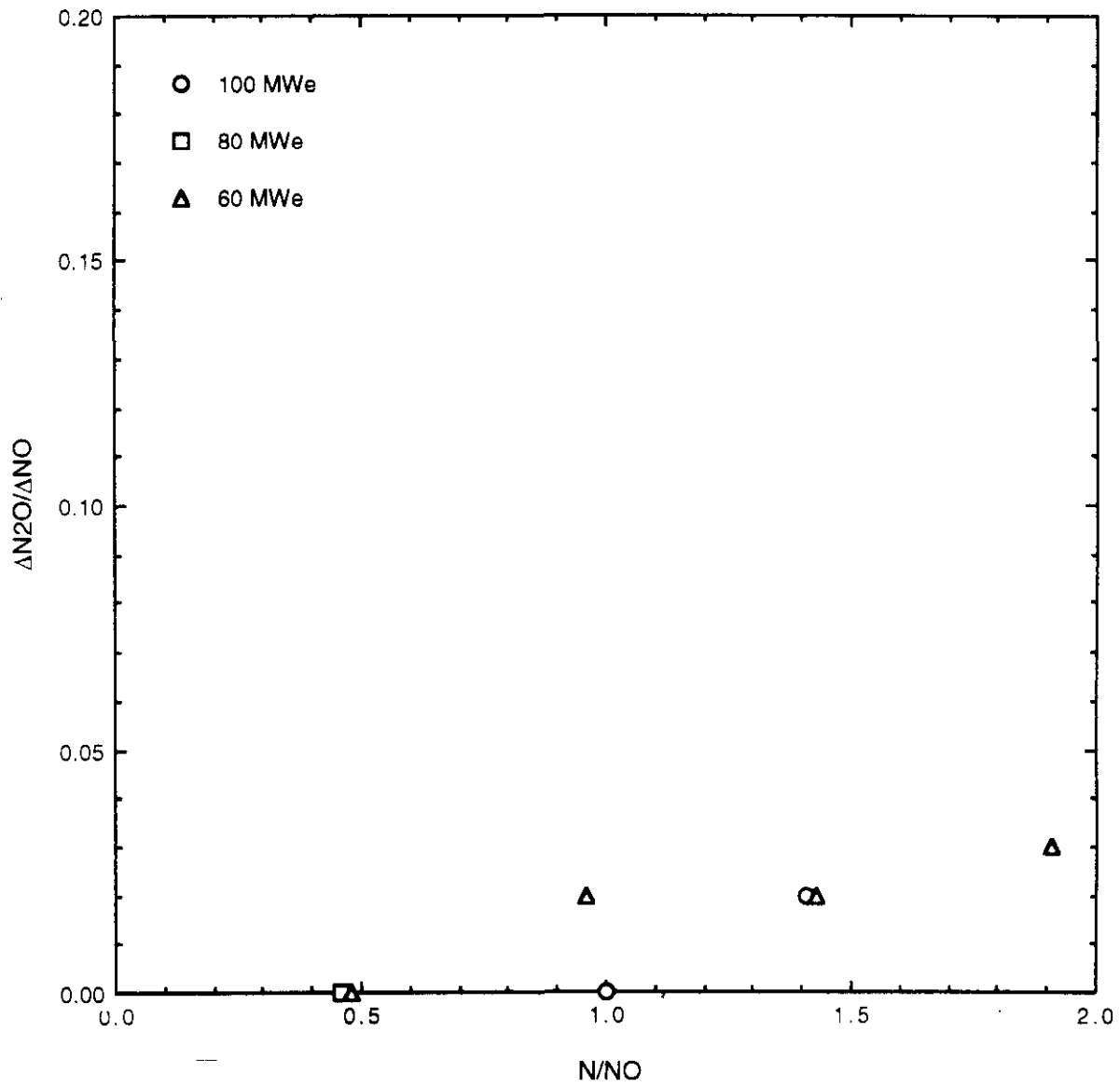
Figure 5-21. N$_2$O Emissions with NH$_4$OH Injection
(Level 1 Injection, 8 psig Air, 7 gpm Total Liquid Flow)

formation and emissions with aqueous ammonia compared to urea is attributable to the different chemical paths that each follows for NO reduction. The $N_2O$ is thought to form primarily by the reaction between NCO and NO; NCO is not a major species formed in the ammonia reaction.

### 5.5.4  CO Emissions

The increase in CO emissions with $NH_4OH$ injection is shown in Figure 5-22. As was discussed in Section 5.4.6, the NDIR CO analyzer has an interference with $N_2O$. Both the as measured and corrected data are shown in Figure 5-22. The corrected data show that the actual increase in CO is on the order of 12 ppm with aqueous ammonia injection at a nominal N/NO ratio of 2.0. Since no extra carbon is injected with the aqueous ammonia, this increase in CO emissions can be attributed to inhibition of the normal CO oxidation reaction.
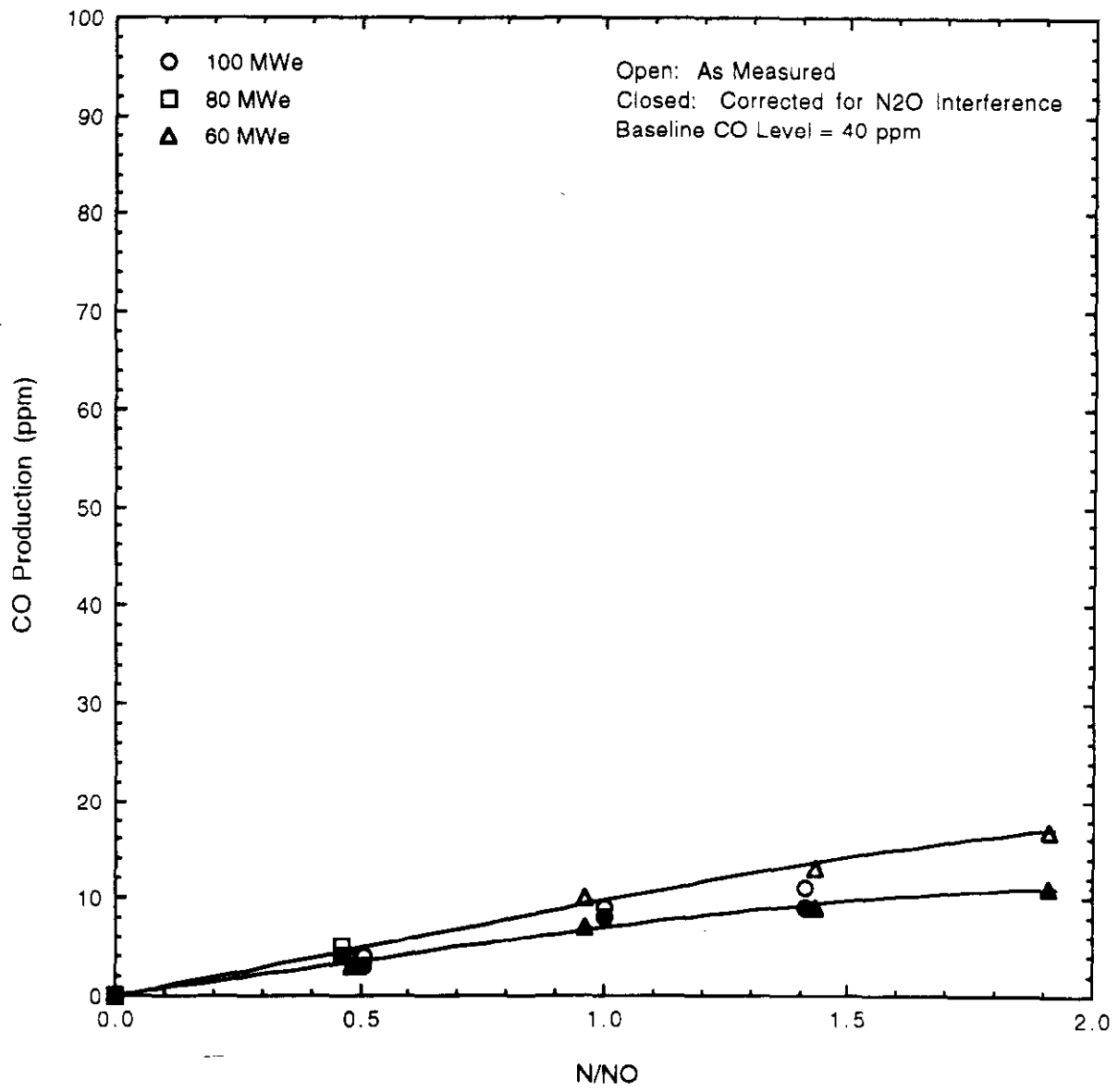
Figure 5-22. CO Production with NH₄OH Injection
(Level 1 Injection, 8 psig Air, 7 gpm Total Liquid Flow)

FERCo-7034-R229

# 6.0 DISCUSSION

During the baseline SNCR test program, the SNCR system was started up and a series of tests was conducted to characterize NO reductions and byproduct formation with both urea and aqueous ammonia ($NH_4OH$) injection. The intent of the test program was to determine the NO reduction potential of SNCR with a high baseline NO level. This data could then be compared with data obtained after the combustion system retrofit when the baseline NO level was substantially lower.

While the results presented in Section 5 are self explanatory, there are three areas that are worthy of discussion in this section of the report.

1.    Comparison of the performance of urea and aqueous ammonia

2.    Plume visibility effects of SNCR

3.    Boiler impacts of SNCR

Each of these areas is discussed below.

## 6.1    COMPARISON OF UREA AND AQUEOUS AMMONIA

For the current test program, it is only possible to compare the performance of urea and aqueous ammonia when the chemicals are injected through the same set of injectors (Level 1). This does not mean that the conclusions made would apply to a system that has been independently optimized for the two different SNCR chemicals. The testing showed that the temperature windows for the two chemicals were different. Peak NO removals occur at lower temperatures with aqueous ammonia injection than with urea injection; thus, the optimum injection location is likely further downstream.

Figure 6-1 compares the NO removals obtained with urea and $NH_4OH$ injection over the boiler load range for N/NO ratios of 1.0 and 1.4, and Figure 6-2 shows the corresponding $NH_3$ emissions. In order to provide a more accurate comparison of the performance of the two chemicals, the data points in both figures were interpolated from the curves in Figures 5-11 and 5-19 for the "exact" (not "nominal") N/NO ratios of 1.0 and 1.4. The curves show that for both
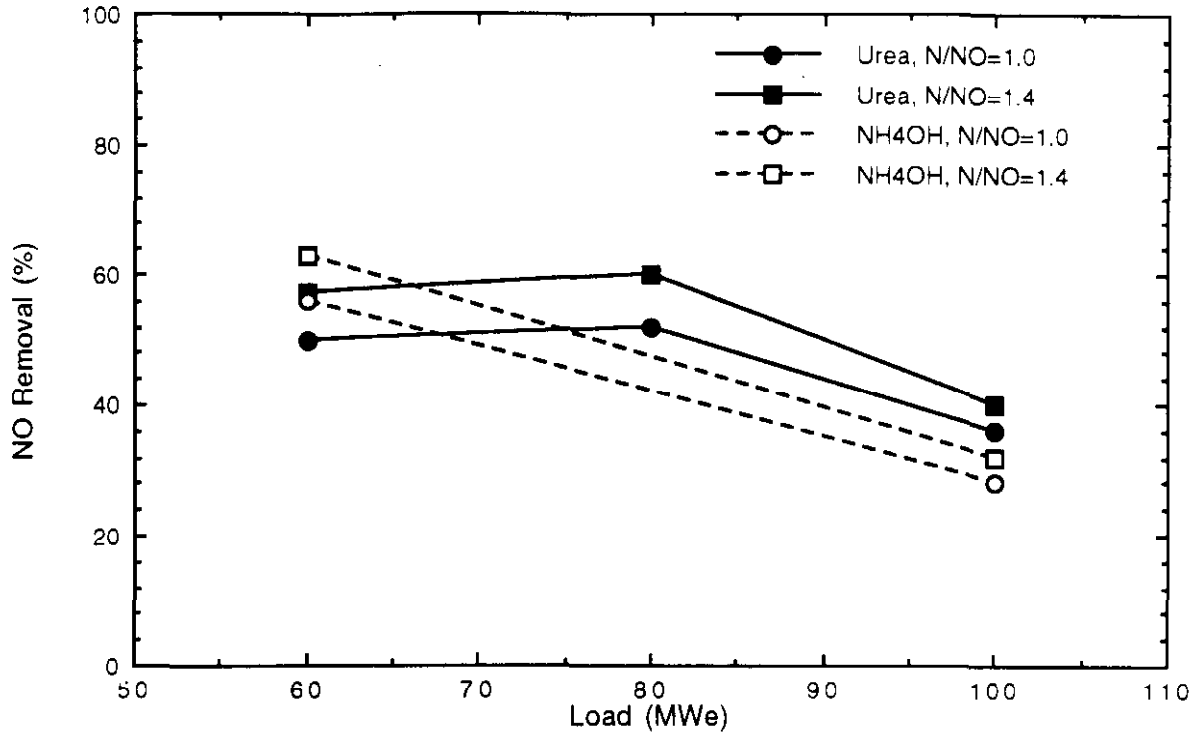
Figure 6-1. Comparison of NO Removals for Urea and $NH_4OH$ Injection
(Level 1 Injection, 8 psig Air, 7 gpm Total Liquid Flow)
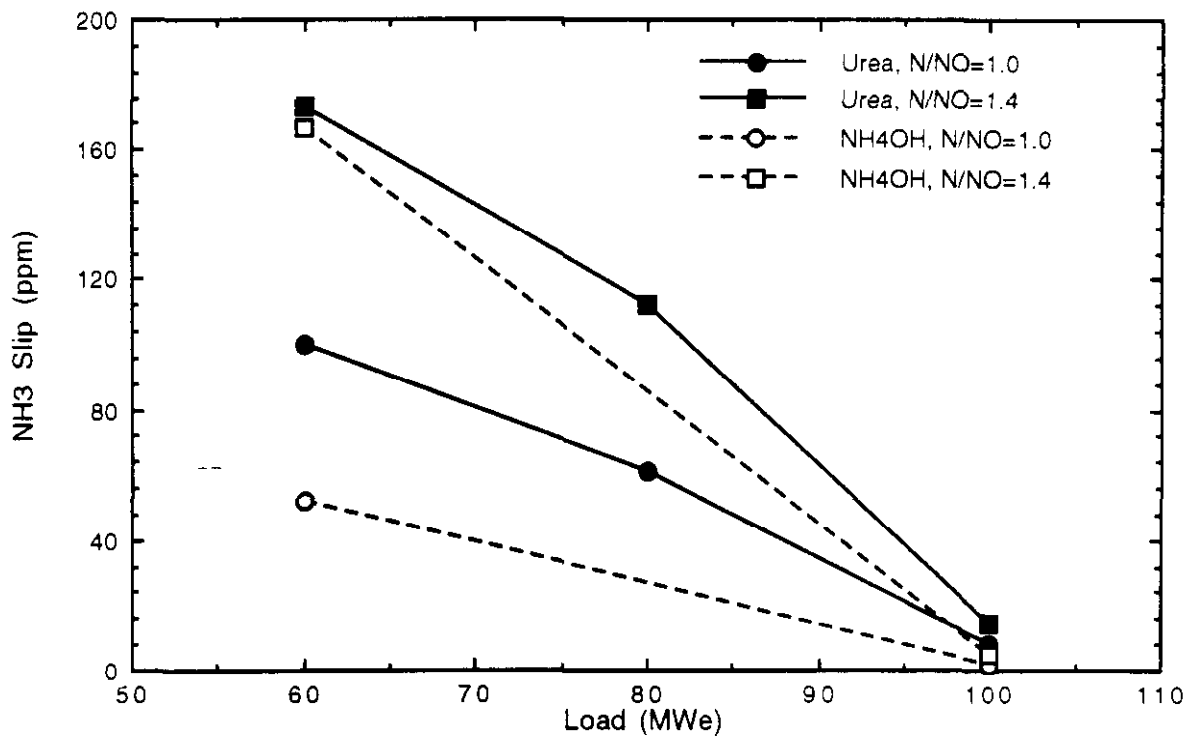


Figure 6-2. Comparison of $NH_3$ Emissions for Urea and $NH_4OH$ Injection
(Level 1 Injection, 8 psig Air, 7 gpm Total Liquid Flow)

N/NO ratios, NO removals are higher with urea than with NH$_4$OH for boiler loads above approximately 65 MWe. However, as seen in Figure 6-2, NH$_3$ emissions are higher with urea injection than with aqueous ammonia injection. Again, it should be emphasized that this comparison is for the same set of injectors and injection parameters for both chemicals and may not be representative of a comparison once the injection system is optimized for each chemical. However, it is evident that the temperature windows are distinctly different for the two chemicals. With urea injection through the Level 1 injectors, peak NO removals occur over the boiler load range of 70 to 85 MWe; whereas, for NH$_4$OH, peak NO removals will occur at boiler loads of 60 MWe or less.

Figure 6-3 shows another comparison between urea and NH$_4$OH injection over the boiler load range. In this figure, NO removal is shown as a function of load, holding the NH$_3$ emissions constant at each boiler load; curves are included for NH$_3$ emissions of 5, 10 and 15 ppm. As was done for Figures 6-1 and 6-2, the data points which define these curves were interpolated from the curves in Figures 5-11 and 5-19. The difference in performance between the two chemicals for a particular NH$_3$ emission limit seems to be dependent on the emission limit chosen. For a limit of 5 ppm, the difference is minimal (on the order of 3 to 4 percent NO removal at best). At 10 and 15 ppm, NH$_4$OH provides a substantial increase in performance at 60 MWe, but at 100 MWe the performance of the two chemicals is similar. Although the reason for the difference in behavior at the 5 ppm limit is not immediately apparent, it is quite possible that it is due to inaccuracies in curve fitting and interpolating the data in Figures 5-11 and 5-19 at such low NH$_3$ slip levels. However, overall the data indicate that on an equal NH$_3$ slip basis, NH$_4$OH injection tends to provide higher NO removals than urea over the boiler load range. For instance, at an NH$_3$ emission limit of 10 ppm, NH$_4$OH injection provides in NO removals of 26 to 36 percent over the boiler load range from 60 to 100 MWe. For the same 10 ppm limit, urea injection provides NO removals from 16 to 36 percent. Again, this comparison is based on using the same set of injectors and injection conditions for both chemicals.

In addition to comparing the performance of urea and NH$_4$OH on a NO removal basis, it is also necessary to look at the efficiency of chemical usage. This is important in this particular application because the amount of NH$_4$OH injected (N/NO ratio) for each fixed NH$_3$ emission limit in Figure 6-3 is greater than the amount of urea injected at the same limit and boiler load.
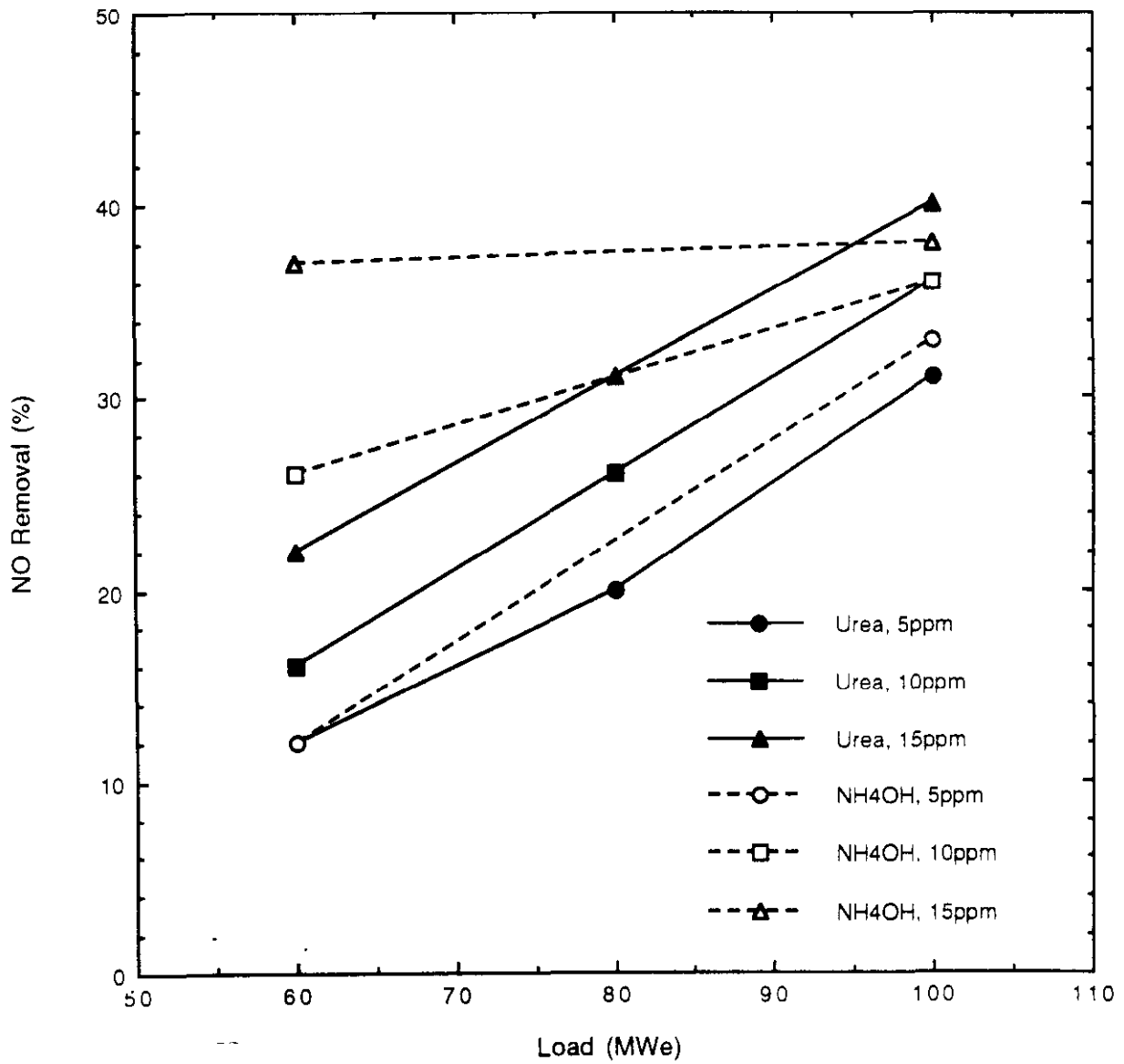
Figure 6-3. Comparison of NO Removals for Urea and $NH_4OH$
for Fixed $NH_3$ Slip Levels of 5, 10, and 15 ppm
(Level 1 Injection, 8 psig Air, 7 gpm Total Liquid Flow)

FERCo-7034-R229

Utilization is used as a measure of the efficiency of chemical usage, and is defined as the NO removal normalized by the amount of chemical injected:

Utilization = (Percent NO Removal)/(N/NO Ratio)

Figure 6-4 shows utilization for both urea and $NH_4OH$ as a function of boiler load for an $NH_3$ emission limit of 10 ppm. At boiler loads in excess of approximately 65 MWe, urea is more efficient than $NH_4OH$. If the cost of the two chemicals were the same (on the basis of $ per mole of nitrogen delivered), the data indicate that urea would be the preferred chemical. However, to make the most accurate comparison, the cost of each chemical must be included in the analysis.

## 6.2    PLUME VISIBILITY

During the course of the SNCR testing, a visible white plume was apparent under some test conditions. This was a detached plume indicating that $NH_3$ was reacting with other species after the combustion products exited the stack and cooled as the plume entrained ambient air. The appearance of the plume was not consistent in that a plume was noticed on some days with low $NH_3$ slips, and then not seen on other days at much higher slip levels. The plume seemed to be related to ambient temperature since it was more prevalent at low temperatures. It was also noted that the baghouse provided a substantial capacity for the absorption and desorption of $NH_3$. When SNCR injection was started, a visible plume would not be observed for 1 to 2 hours. Likewise, when the SNCR system was shut down, the visible plume would often persist for a number of hours.

To characterize the phenomenon, a test was run on a Monday after the SNCR system had been shut down for two days over the weekend. In this way, the ash contained in the baghouse would be free of $NH_3$. For this test, the boiler was operated at a load of 100 MWe and urea was injected at a nominal N/NO ratio of 1.0. This resulted in an NO removal of 46 percent. The $NH_3$ level at the inlet to the baghouse was measured at the start of the test, and boiler and urea injection conditions were then held constant for the next 6-1/2 hours. $NH_3$ measurements at the baghouse exit were then made at nominally 1-hour intervals. The results of these tests are shown in Figure 6-5. For this test condition, the $NH_3$ concentration measured at the inlet to the baghouse was 8 ppm. It took over 3 hours for this level of $NH_3$ to appear at the baghouse outlet,
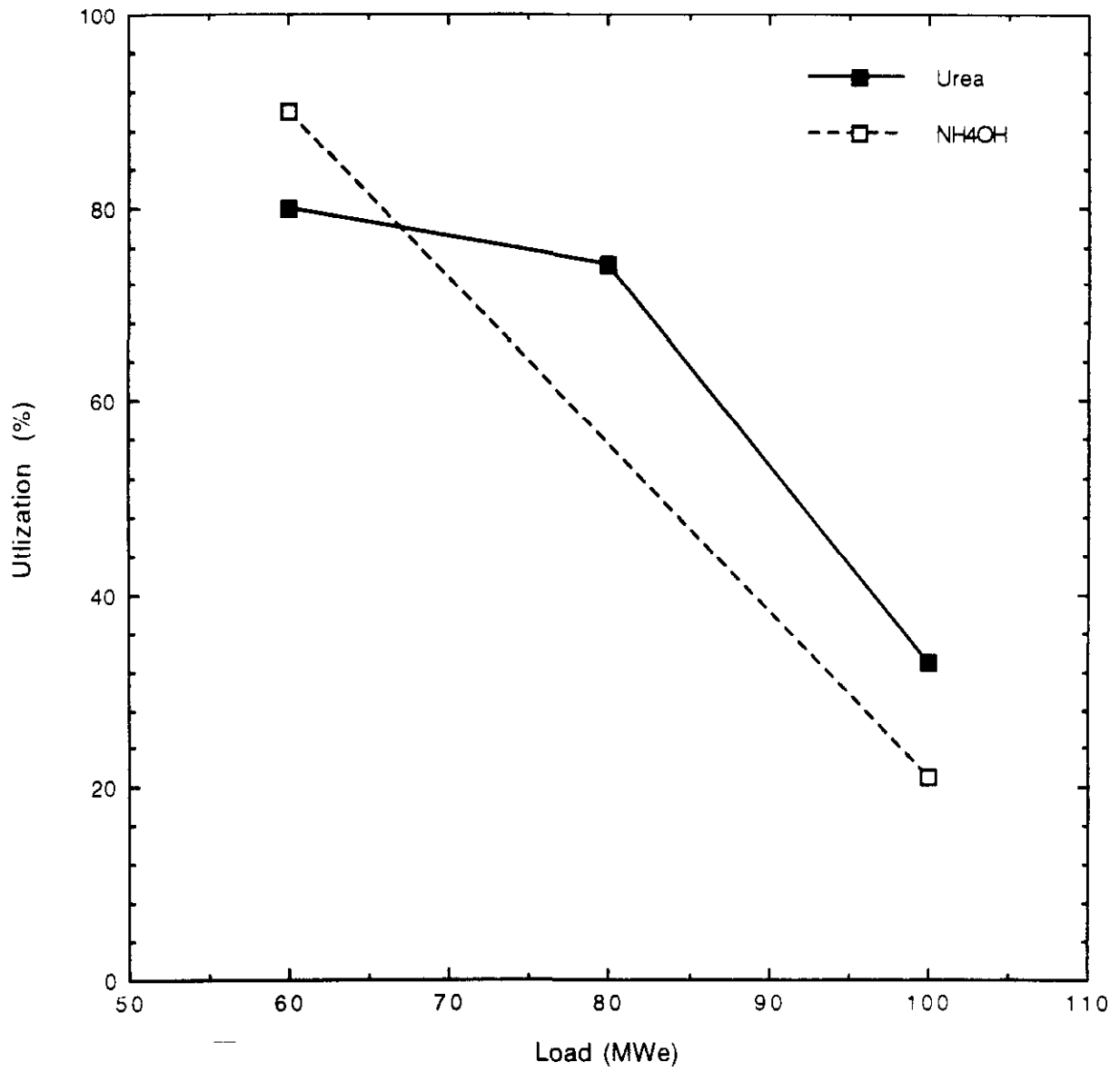
Figure 6-4. Comparison of Chemical Utilization for Urea and $NH_4OH$ for 10 ppm $NH_3$ Slip
(Level 1 Injection, 8 psig Air, 7 gpm Total Liquid Flow)
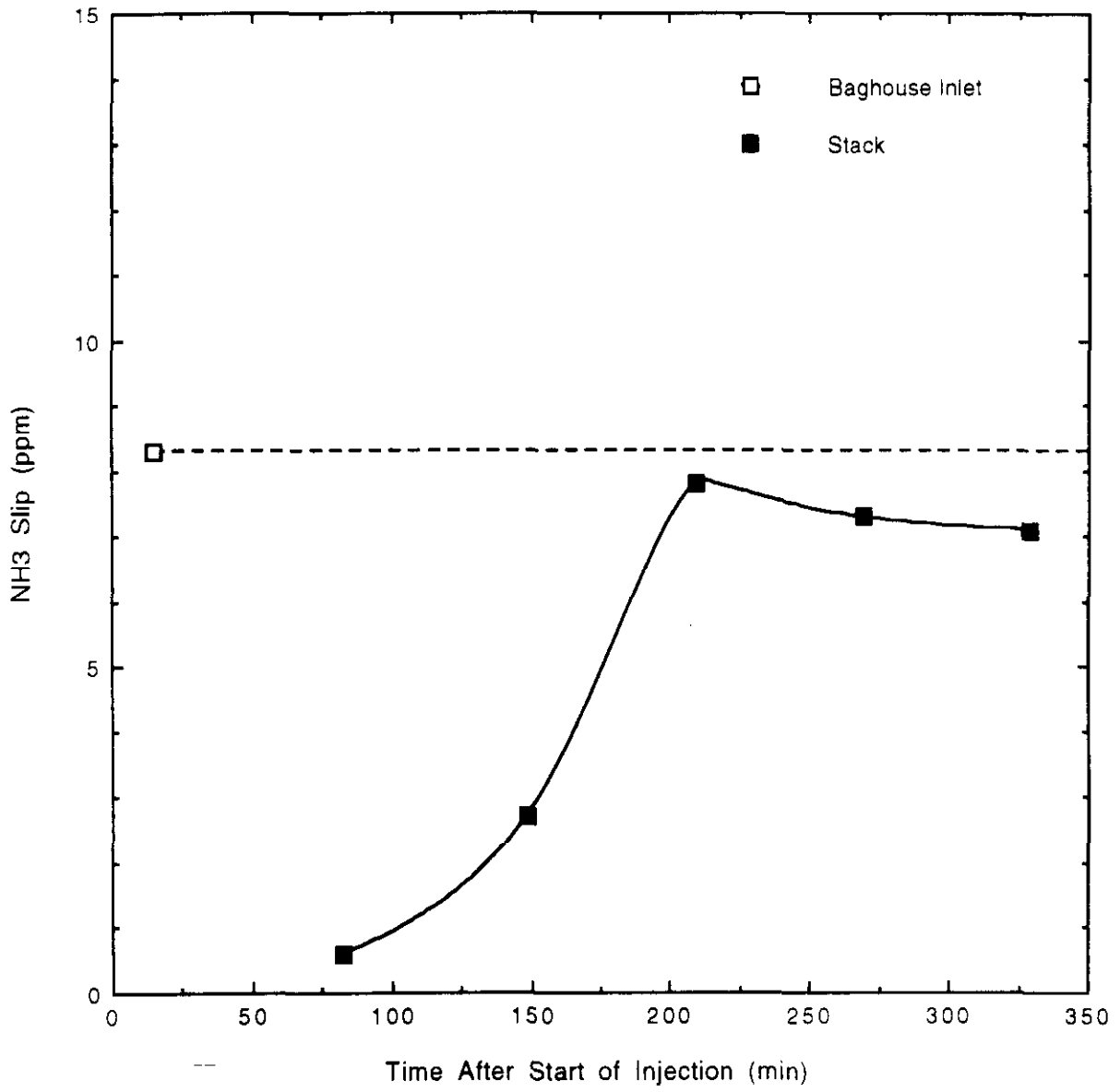
Figure 6-5. Baghouse Inlet/Outlet NH₃ Emissions for Urea Injection
(100 MWe, Level 1 Injection, N/NO ≈ 1.0, 8 psig Air, 16 gpm Total Liquid Flow)

indicating that the ash in the baghouse provides a fairly substantial capacity for absorbing and desorbing $NH_3$. During this test, ash samples were also obtained from the baghouse hoppers and analyzed for ammonia. The results of these tests are shown in Table 6-1.

Table 6-1

BAGHOUSE ASH AMMONIA CONCENTRATION

| Time After Injection (min) | $NH_3$ Concentration mg $NH_3$/gm ash |
|---|---|
| 0 | 13.6 |
| 200 | 39.4 |
| 405 | 11.1 |

Prior to urea injection, the measured ammonia concentration in the ash was low. The sample taken 200 minutes after the start of injection showed the ammonia content increasing. However, the sample collected 405 minutes into the test shows an ammonia concentration similar to that seen before injection. The scatter in the data is likely the result of the ash sample not being a representative composite of the 12 baghouse compartment hoppers.

The data in Figure 6-5 show the basic time constant necessary to attain steady state conditions at the stack, and the difficulties this poses in assessing the plume visibility issue. To adequately characterize the plume visibility issue, each injection test will have to be conducted for a nominal 4 to 5 hour period, which was not feasible during the current test program.

The next question is what reactions are contributing to the detached, visible plume? The Arapahoe Unit 4 flue gas has low $SO_3$ concentrations (less than 1 ppm), and the $SO_3$ would be expected to react with $NH_3$ at temperatures of 400 to 600°F, forming ammonium sulfate or ammonium bisulfate that would be removed in the baghouse. Therefore, the visible plume is likely due to ammonium salt formation through reactions with either HCl or $SO_2$ in the flue gas. Coal analyses during the baseline tests showed coal chlorine contents ranging from 0 to 0.04 percent (corresponding to a flue gas HCl concentration on the order of 40 ppm). At concentrations of HCl and $NH_3$ of 40 and 10 ppm, respectively, reactions forming solid ammonium chloride would be expected when the plume cooled below about 230°F.

Reactions between $NH_3$ and $SO_2$ could also occur in the plume forming ammonium sulfite, pyrosulfite or bisulfite compounds. These reactions occur at lower temperatures than the reactions forming ammonium chloride. If the $SO_2$-$NH_3$ reactions are contributing to plume visibility, this would only be expected at relatively low ambient temperature. Since plume formation at Arapahoe Unit 4 seemed to be more prevalent at low ambient temperatures, the reactions between $SO_2$ and $NH_3$ may be responsible.

It was beyond the scope of the present test program to adequately characterize the plume reaction, however, further study will be done during the post-retrofit SNCR testing. This is an important issue in that plume visibility may dictate the level of $NH_3$ emissions that can be tolerated, and thus the overall performance of the SNCR system with either urea or aqueous ammonia.

6.3 SYSTEM IMPACTS

Operation of the SNCR system can result in some impacts to the balance of the plant. In the previous subsection, the plume visibility issue was discussed, as well as ammonia absorption by the ash in the baghouse. Depending on the amount of ammonia contained in the ash, ash handling, disposal and use may be impacted. These impacts were not addressed during the current test program.

Other operational impacts of the SNCR system are 1) energy penalties associated with operating compressors and pumps, 2) boiler efficiency penalties associated with dry gas losses from the mixing air and vaporization of the aqueous solutions, and 3) impacts of injection on steam attemperation. While the first two impacts may be calculated for a system, the third requires additional discussion.

During the current test program, the effect of the injection process on steam attemperation varied from little or none, to a very pronounced effect, depending on the total liquid flow rate. Although the abbreviated nature of the test program did not allow quantitative assessment of this effect, some general observations can be made. At the lowest liquid flow rate (7 gpm), the effect was minimal in that although the attemperator valves would close slightly once injection started, there was sufficient range remaining in which to control steam temperature. At the highest flow rate

(28 gpm) however, the attemperator valves would often close completely, and steam temperatures would slowly fall until the air/fuel ratio was increased to provide sufficient heat transfer in the convective pass and bring the steam temperatures back up to normal levels. It became necessary when testing at the 28 gpm condition to set the unit up with a slightly higher average $O_2$ than normal before starting injection in order to avoid having to make an adjustment later, midway through a test. These effects were seen at all loads tested (60, 80 and 100 MWe), although the effect was more pronounced at lower loads.

The actual energy and boiler efficiency penalties associated with the SNCR system were not characterized during this test program due to the high cost of a detailed heat rate test. However, an order of magnitude estimate of the impacts is provided below.

Mixing air: Penalties associated with the mixing air include power to operate the centrifugal compressor and dry gas losses in the furnace. To date, the power consumption has not been quantified, but is expected to be on the order of 0.2 to 0.4 percent of the unit output. Over an operating pressure range of 8 to 12 psig, the mixing air flow rate varies from 3900 to 4800 scfm. This is nominally 1.5 to 2.0 percent of the flue gas flow. This amount of additional gas flow through the boiler will reduce boiler efficiency by nominally 0.1 percent. Thus, the mixing air will result in a decrease in efficiency on the order of 0.3 to 0.5 percent.

Liquid injection: The primary penalties associated with liquid injection are the latent heat of vaporization of the aqueous solution and the additional energy flow out the stack due to the increased mass flow. The energy penalty is dependent on the amount of liquid flow and will range from nominally 0.4 to 1.6 percent for liquid flows of 7 to 28 gpm, respectively.

Overall energy penalties: The combination of the air and liquid losses discussed above yields an order of magnitude estimate of an efficiency penalty of 0.7 to 2.1 percent depending upon the amount of air and liquid injected. During the current abbreviated test program, the SNCR injection system was "optimized" at an air injection pressure of 8 psig and a total liquid flow rate of 7 gpm. This condition corresponds to an efficiency penalty of approximately 0.7 percent.

Steam temperature: Steam temperature penalties would be a factor when the total liquid injection rate was high enough to cause the attemperators to close completely, resulting in a decrease in steam temperature. At Arapahoe Unit 4, the design steam temperature is 1000°F. Steam temperature decreases of 50 and 100°F will result in heat rate losses of 1.5 and 3.0 percent, respectively. These figures are from the turbine manufacturer, and are specific to Arapahoe Unit 4.

FERCo-7034-R229

# 7.0 CONCLUSIONS AND OBSERVATIONS

Although the short duration of the test program did not allow a full characterization and optimization of the SNCR system, the following conclusions and observations can be made regarding the performance of the system with the original combustion hardware on the Arapahoe Unit 4 boiler.

## Urea

- With the Level 1 injectors and nominal N/NO ratio of 1.0, NO removals of greater than 50 percent were achievable over the boiler load range of 60 to 85 MWe. However, $NH_3$ emissions ranged from 50 to 100 ppm at these conditions.

- Low NO removals and high ammonia emissions indicated that the temperature at the Level 2 injection point was too low for adequate performance with urea.

- Changes in nozzle parameters (air and liquid orifice sizes) had little effect on NO removals.

- Although mixing air flow rate had a minimal effect on NO removal, a large effect was seen on $NH_3$ emissions with slips increasing from a baseline of 10 to 50 ppm when the air flow rate was reduced from 3900 to 1700 scfm.

- Variations in boiler load and dilution water flow showed the largest effects on system performance, with the effect of each resulting from the effect on the local flue gas temperature at the point of injection.

## $NH_4OH$

- With $NH_4OH$ injection at a nominal N/NO ratio of 1.0, peak NO removals of 55 percent occurred at a boiler load of 60 MWe, indicating that the optimum temperature window for $NH_4OH$ is markedly lower than that for urea. The $NH_3$ slip for this condition was 51 ppm.

## Comparison of Urea and $NH_4OH$

- Although NO removals were found to be higher with urea than with $NH_4OH$ for a given N/NO ratio over nearly the entire load range (65 to 110 MWe), $NH_3$ emissions were also found to be higher.

- On an equal ammonia slip basis, $NH_4OH$ injection tends to provide higher NO removals than urea. For a 10 ppm $NH_3$ emission limit, NO removals of 26 to 36 percent were achievable with $NH_4OH$ over the load range of 60 to 100 MWe, while urea injection resulted in removals of 16 to 36 percent.

- Over the load range of 65 to 100 MWe, urea was the most efficient chemical.

- Consistent with previous studies, $N_2O$ emissions with $NH_4OH$ injection were lower than with urea injection. For $NH_4OH$, the fraction of NO converted to $N_2O$ was less than 2 percent at a nominal N/NO ratio of 1.0, irrespective of load. With urea, the conversion ranged from 10 to 15 percent at 100 and 60 MWe, respectively.

- The increase in CO emissions with $NH_4OH$ injection was also found to be lower than that found with urea injection. For $NH_4OH$, the increase in CO was on the order of 8 ppm at a nominal N/NO ratio of 1.0, irrespective of load. With urea, the increase ranged from 10 to 36 ppm at 100 and 60 MWe, respectively.


The above comparisons of the performance of urea and $NH_4OH$ are for injection through the same set of injectors (Level 1) and for the same set of injection conditions (8 psig air and 7 gpm total liquid flow). These conclusions may not apply to a system that has been independently optimized for the two different SNCR chemicals.

# 8.0 REFERENCES

1.    Shiomoto, G.H., Smith, R.A., "Integrated Dry $NO_x/SO_2$ Emissions Control System Baseline Test Report," DOE Contract Number DE-FC22-91PC90550, March 1992.

2.    Muzio, L.J., Arand, J.K., "Homogeneous Gas Phase Decomposition of Oxides of Nitrogen," EPRI FP-253, August 1976.

3.    Teixeira, D.P., Muzio, L.J., Montgomery, T.A., "$N_2O$ Emissions from SNCR Processes," presented at the First International Conference on Combustion Technologies for a Clean Environment, Vilamoura, Portugal, September 1991.

4.    Smith, R.A., "Flue Gas Temperature Measurement, Trip Report, Public Service Company of Colorado", Fossil Energy Research Corp., June 1991.

5.    Martz, T. D., "Evaluation of Urea Injection System Designs for Arapahoe Unit 4 through Cold Flow Modeling", Fossil Energy Research Corp., July 1991.

6.    Teixeira, D.P., et al., "Selective Non-Catalytic Reduction (SNCR) Field Evaluation in Utility Natural Gas-Fired Boilers," GRI92-0083, March 1992.

7.    Muzio, L.J., et al., "$N_2O$ Formation in Selective Non-Catalytic $NO_x$ Reduction Processes," presented at the American Flame Research Committee 1990 Fall International Symposium, November 1990.

- APPENDIX -

DATA SUMMARY

PSCC Arapahoe Unit 4  Baseline/Urea Data Summary

| Test | Date | Time | Comments | Load MWe | Mills OOS | CHO2 % wet | Urea gpm | Air P psig | O2 % | CO ppm | COc ppm@3% | NO ppm | NOc ppm@3% | CO2 % | SO2 ppm | SO2c ppm@3% | N2O ppm | N2Oc ppm(1) | NH3 ppm(2) | NH3 ppm(3) | N/NO | VNO % | Utiliz % | ΔN2O/ΔNOx | ΔCO ppm |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 51 | 02/04/92 | 08.10 | 100 MWe, C mill OOS, as found | 100 | C | 4.10 | 0.00 | 0 | 5.05 | 42 | 47 | 805 | 908 | 13.8 | 360 | 406 | - | - | - | - | 0.00 | 0.0 | - | - | 0 |
| 52 | 02/04/92 | 13.30 | Repeat | 100 | C | | 0.00 | 0 | 5.01 | 43 | 48 | 800 | 901 | 13.8 | 356 | 401 | - | - | - | - | 0.00 | 0.8 | - | - | 0 |
| 53 | 02/04/92 | 13.56 | level 2, 12 psi air only, 1.625" noz | 100 | C | | 0.00 | 12 | 5.25 | 43 | 49 | 798 | 914 | 13.6 | 347 | 397 | - | - | - | - | 0.00 | -0.7 | - | - | 1 |
| 54 | 02/04/92 | 14.07 | Air and water only, .09375" liq orif | 100 | C | | 0.00 | 12 | 5.01 | 44 | 50 | 790 | 889 | 13.8 | 352 | 396 | - | - | - | - | 0.00 | 2.1 | - | - | 2 |
| 55 | 02/04/92 | 14.49 | 28 gpm liq, 12 psi air, N/NO-1.0 | 99 | C | 3.90 | 2.50 | 12 | 5.17 | 65 | 74 | 606 | 689 | 13.8 | 130 | 148 | - | - | - | - | 1.13 | 24.1 | 21.3 | - | 26 |
| 56 | 02/05/92 | 09.22 | Baseline, Lvl 2, 1.625"air/.09375"liq | 101 | | 4.05 | 0.00 | 0 | 4.95 | 41 | 46 | 764 | 857 | 13.8 | 350 | 399 | - | - | 0 | - | 0.00 | 2.4 | - | - | 0 |
| 57 | 02/05/92 | 13.30 | Baseline repeat | 101 | | 4.20 | 0.00 | 0 | 5.08 | 38 | 43 | 795 | 899 | 13.8 | 358 | 405 | - | - | - | - | 0.00 | -2.4 | - | - | 0 |
| 58 | 02/05/92 | 14.29 | 28 gpm liq, 12 psi air, N/NO-1.0 | 101 | | 4.30 | 2.20 | 12 | 5.22 | 68 | 78 | 565 | 644 | 13.7 | 160 | 182 | - | - | 100+ | 294 | 1.02 | 26.7 | 26.2 | - | 35 |
| 59 | 02/05/92 | 16.35 | 28 gpm liq, 8 psi air, N/NO-1.0 | 101 | | 4.20 | 2.20 | 8 | 5.25 | 72 | 82 | 567 | 649 | 13.7 | 159 | 181 | - | - | 100+ | - | 1.01 | 26.1 | 25.9 | - | 39 |
| 60 | 02/06/92 | 08.50 | Baseline, Lvl 1, 1.25"air/.09375"liq | 100 | | 4.10 | 0.00 | 0 | 5.00 | 38 | 43 | 804 | 905 | 13.7 | 362 | 362 | - | - | - | - | 0.00 | -0.2 | - | - | 0 |
| 61 | 02/06/92 | 10.23 | 28 gpm liq, 8 psi air, N/NO-2.0 | 100 | | 4.10 | 4.40 | 8 | 5.03 | 94 | 106 | 303 | 341 | 13.9 | 319 | 359 | - | - | 14 | - | 1.98 | 62.3 | 31.4 | - | 63 |
| 62 | 02/06/92 | 11.05 | 28 gpm liq, 8 psi air, N/NO-1.5 | 101 | | 4.06 | 3.30 | 8 | 5.01 | 84 | 95 | 350 | 393 | 13.8 | 342 | 384 | - | - | 10 | - | 1.47 | 56.5 | 38.4 | - | 52 |
| 63 | 02/06/92 | 13.24 | 28 gpm liq, 8 psi air, N/NO-1.0 | 101 | | 4.04 | 2.20 | 8 | 4.86 | 80 | 89 | 384 | 428 | 13.9 | 358 | 358 | - | - | 6 | 46 | 0.98 | 52.6 | 53.6 | - | 46 |
| 64 | 02/06/92 | 15.40 | 28 gpm liq, 8 psi air, N/NO-0.5 | 101 | | 3.95 | 1.10 | 8 | 4.86 | 66 | 74 | 502 | 559 | 13.9 | 374 | 417 | - | - | - | - | 0.49 | 38.1 | 77.7 | - | 31 |
| 65 | 02/06/92 | 17.04 | Baseline repeat | 101 | | 4.01 | 0.00 | 0 | 5.00 | 39 | 44 | 801 | 901 | 13.9 | 360 | 405 | - | - | 0 | - | 0.00 | 0.3 | - | - | 1 |
| 66 | 02/07/92 | 08.15 | Baseline, Lvl 1, 1.25"air/.086"liq | 100 | | 4.01 | 0.00 | 0 | 4.90 | 38 | 43 | 782 | 874 | 14.1 | 352 | 394 | - | - | 0 | - | 0.00 | 1.1 | - | - | 0 |
| 67 | 02/07/92 | 10.30 | 28 gpm liq, 12 psi air, N/NO-2.0 | 100 | | 4.06 | 4.35 | 12 | 4.91 | 89 | 100 | 304 | 340 | 13.9 | 315 | 353 | - | - | 13 | - | 2.00 | 61.5 | 30.7 | - | 57 |
| 68 | 02/07/92 | 11.50 | 28 gpm liq, 12 psi air, N/NO-1.5 | 100 | | 3.79 | 3.25 | 12 | 4.89 | 82 | 92 | 335 | 375 | 13.8 | 330 | 369 | - | - | 7 | - | 1.50 | 57.6 | 38.5 | - | 49 |
| 69 | 02/07/92 | 13.42 | 28 gpm liq, 12 psi air, N/NO-1.0 | 100 | | 3.96 | 2.15 | 12 | 4.98 | 73 | 82 | 403 | 453 | 13.9 | 334 | 375 | - | - | 5 | - | 0.99 | 48.8 | 49.3 | - | 39 |
| 70 | 02/07/92 | 14.54 | 28 gpm liq, 12 psi air, N/NO-0.5 | 100 | | 3.89 | 1.08 | 12 | 5.00 | 58 | 65 | 527 | 593 | 13.8 | 357 | 401 | - | - | 0 | - | 0.50 | 32.9 | 66.2 | - | 22 |
| 71 | 02/07/92 | 16.27 | Baseline repeat | 100 | | 4.12 | 0.00 | 0 | 4.97 | 39 | 44 | 796 | 894 | 13.8 | 349 | 392 | - | - | 0 | - | 0.00 | -1.1 | - | - | 1 |
| 72 | 02/10/92 | 09.04 | Baseline, Lvl 1, 1.5"air/.086"liq | 112 | | 4.03 | 0.00 | 0 | 4.89 | 37 | 41 | 848 | 948 | 13.9 | 441 | 491 | 8 | 5 | 0 | - | 0.00 | 0.0 | - | - | 0 |
| 73 | 02/10/92 | 10.43 | 28 gpm liq, 8 psi air, N/NO-0.5 | 111 | | 3.82 | 1.17 | 8 | 4.92 | 45 | 50 | 642 | 718 | 13.9 | 441 | 493 | 28 | 5 | 0 | - | 0.45 | 24.3 | 53.6 | 0.10 | 9 |
| 74 | 02/10/92 | 11.20 | 28 gpm liq, 12 psi air, N/NO-0.75 | 111 | | 3.90 | 1.77 | 12 | 4.93 | 49 | 55 | 582 | 652 | 13.8 | 441 | 494 | 37 | 5 | 0 | - | 0.68 | 31.2 | 45.6 | 0.11 | 14 |
| 75 | 02/10/92 | 12.04 | 28 gpm liq, 8 psi air, N/NO-1.0 | 111 | | 4.04 | 2.34 | 8 | 4.88 | 53 | 59 | 541 | 604 | 13.9 | 450 | 502 | 43 | 5 | 0 | - | 0.91 | 36.3 | 40.1 | 0.11 | 18 |
| 76 | 02/10/92 | 13.20 | Baseline repeat, with air & water | 111 | | 4.00 | 0.00 | 8 | 4.89 | 37 | 41 | 835 | 933 | 13.8 | 433 | 484 | 8 | 5 | 0 | 4 | 0.00 | 1.6 | - | -0.02 | 0 |
| 77 | 02/10/92 | 16.17 | 28 gpm liq, 8 psi air, N/NO-1.25 | 111 | | 4.05 | 2.92 | 8 | 4.96 | 58 | 65 | 502 | 563 | 13.8 | 470 | 527 | 55 | 5 | 19 | - | 1.13 | 40.6 | 35.9 | 0.13 | 24 |
| 78 | 02/10/92 | 17.02 | 28 gpm liq, 12 psi air, N/NO-1.0 | 111 | | 4.20 | 2.36 | 12 | 5.15 | 52 | 59 | 532 | 604 | 13.8 | 463 | 526 | 45 | 5 | 13 | 8 | 0.91 | 36.3 | 39.7 | 0.12 | 18 |
| 79 | 02/10/92 | 17.50 | 28 gpm liq, 12 psi air, N/NO-0.5 | 111 | | 4.11 | 1.17 | 12 | 5.15 | 42 | 48 | 653 | 741 | 13.7 | 451 | 512 | 28 | 5 | 2 | - | 0.45 | 21.8 | 48.2 | 0.10 | 7 |
| 80 | 02/11/92 | 09.05 | Baseline repeat | 100 | | 4.17 | 0.00 | 0 | 4.84 | 35 | 39 | 820 | 913 | 13.9 | 460 | 512 | 8 | 5 | 0 | - | 0.00 | -1.4 | - | 0.03 | 1 |
| 81 | 02/11/92 | 11.00 | 28 gpm liq, 8 psi air, N/NO-0.5 | 101 | | 3.65 | 1.15 | 8 | 4.53 | 50 | 55 | 560 | 612 | 14.3 | 479 | 523 | 34 | 5 | 0 | - | 0.51 | 32.0 | 62.6 | 0.10 | 17 |
| 82 | 02/11/92 | 12.05 | 28 gpm liq, 8 psi air, N/NO-0.75 | 101 | | 3.69 | 1.70 | 8 | 4.46 | 58 | 63 | 482 | 524 | 14.4 | 468 | 509 | 46 | 5 | 0 | - | 0.76 | 41.8 | 55.2 | 0.12 | 25 |
| 83 | 02/11/92 | 13.20 | Baseline repeat, with air & water | 101 | | 3.75 | 0.00 | 8 | 4.65 | 37 | 41 | 767 | 844 | 14.3 | 483 | 532 | 8 | 5 | 0 | - | 0.00 | 6.2 | - | 0.00 | 3 |
| 84 | 02/11/92 | 14.14 | 28 gpm liq, 8 psi air, N/NO-1.0 | 101 | | 4.05 | 2.30 | 8 | 4.95 | 64 | 72 | 429 | 482 | 14.0 | 469 | 526 | 57 | 5 | 3 | 37 | 1.02 | 46.4 | 45.4 | 0.13 | 34 |
| 85 | 02/11/92 | 15.50 | 28 gpm liq, 8 psi air, N/NO-1.5 | 100 | | 4.06 | 3.40 | 8 | 4.93 | 70 | 78 | 381 | 426 | 14.0 | 460 | 515 | 70 | 5 | 19 | - | 1.53 | 52.7 | 34.5 | 0.15 | 40 |
| 86 | 02/11/92 | 16.55 | 28 gpm liq, 12 psi air, N/NO-1.5 | 101 | | 4.10 | 3.40 | 12 | 4.95 | 68 | 76 | 379 | 425 | 13.9 | 455 | 510 | 69 | 5 | 13 | - | 1.51 | 52.8 | 34.9 | 0.14 | 38 |
| 87 | 02/11/92 | 17.30 | 28 gpm liq, 12 psi air, N/NO-1.0 | 101 | | 4.11 | 2.30 | 12 | 5.17 | 61 | 69 | 438 | 498 | 13.8 | 467 | 531 | 54 | 5 | 2 | 27 | 1.02 | 44.7 | 43.7 | 0.12 | 31 |
| 88 | 02/11/92 | 18.15 | 28 gpm liq, 12 psi air, N/NO-0.5 | 101 | | 4.28 | 1.15 | 12 | 5.20 | 47 | 54 | 557 | 635 | 13.7 | 465 | 530 | 34 | 5 | 0 | - | 0.51 | 29.4 | 57.6 | 0.10 | 16 |
| 89 | 02/11/92 | 19.00 | Baseline repeat | 100 | | 4.41 | 0.00 | 0 | 5.10 | 33 | 37 | 833 | 943 | 13.9 | 460 | 521 | 8 | 5 | 0 | - | 0.00 | -4.8 | - | 0.00 | -1 |
| 90 | 02/12/92 | 08.30 | Baseline, Lvl 1, 1.5"air/.086"liq | 80 | | 4.02 | 0.00 | 0 | 4.86 | 37 | 41 | 669 | 746 | 13.9 | 403 | 449 | 7 | 7 | 4 | - | 0.00 | 0.0 | - | - | 0 |
| 91 | 02/12/92 | 10.50 | 28 gpm liq, 8 psi air, N/NO-0.5 | 79 | | 4.16 | 0.75 | 8 | 5.23 | 58 | 66 | 443 | 505 | 13.4 | 400 | 457 | 40 | 7 | 4 | - | 0.52 | 32.3 | 62.4 | 0.13 | 25 |
| 92 | 02/12/92 | 11.50 | 28 gpm liq, 8 psi air, N/NO-0.75 | 79 | | 4.18 | 1.12 | 8 | 5.19 | 65 | 74 | 373 | 424 | 13.7 | 368 | 419 | 52 | 7 | 11 | - | 0.77 | 43.2 | 55.8 | 0.14 | 33 |
| 93 | 02/12/92 | 12.40 | 28 gpm liq, 8 psi air, N/NO-1.0 | 79 | | 3.94 | 1.56 | 8 | 5.03 | 73 | 82 | 314 | 354 | 13.8 | 324 | 365 | 64 | 7 | 40 | - | 1.08 | 52.5 | 48.8 | 0.15 | 41 |
| 94 | 02/12/92 | 13.37 | 28 gpm liq, 12 psi air, N/NO-1.0 | 79 | | 4.04 | 1.56 | 12 | 5.04 | 73 | 82 | 309 | 349 | 13.8 | 324 | 366 | 63 | 7 | 30 | 98 | 1.08 | 53.2 | 49.4 | 0.14 | 41 |
| 95 | 02/12/92 | 14.45 | Baseline repeat, with air & water | 79 | | 4.27 | 0.00 | 0 | 5.15 | 35 | 40 | 672 | 763 | 13.7 | 383 | 435 | 9 | 7 | 0 | 8.4stk | 0.00 | -2.3 | - | 0.64 | -1 |
| 96 | 02/12/92 | 16.05 | 28 gpm liq, 8 psi air, N/NO-1.5 | 79 | | 4.19 | 2.26 | 8 | 5.28 | 45 | 52 | 322 | 368 | 13.7 | 313 | 358 | 63 | 7 | 35 | - | 1.56 | 50.7 | 32.5 | 0.15 | 11 |
| 97 | 02/12/92 | 17.15 | 28 gpm liq, 8 psi air, N/NO-1.0 | 79 | | 4.22 | 1.51 | 8 | 5.39 | 69 | 80 | 338 | 389 | 13.5 | 305 | 352 | 60 | 7 | 28 | - | 1.04 | 47.9 | 45.9 | 0.15 | 39 |
| 98 | 02/12/92 | 17.40 | N/NO 1.0, inside nozzles OOS (5,6) | 79 | | 4.25 | 1.51 | 8 | 5.32 | 63 | 72 | 380 | 436 | 13.5 | 300 | 344 | 53 | 7 | 46 | - | 1.04 | 41.6 | 39.9 | 0.15 | 31 |
| 99 | 02/12/92 | 17.50 | N/NO 1.0, outside nozzles OOS (1,10) | 79 | | 4.34 | 1.51 | 8 | 5.35 | 72 | 83 | 335 | 385 | 13.4 | 305 | 351 | 64 | 7 | 25 | - | 1.04 | 48.4 | 46.4 | 0.16 | 42 |
| 100 | 02/12/92 | 23.19 | Baseline, Lvl 1, 1.5"air/.086"liq | 60 | | 4.42 | 0.00 | 0 | 7.05 | 32 | 41 | 700 | 903 | 11.8 | 312 | 403 | 8 | 7 | 0 | - | 0.00 | 0.0 | - | - | 0 |
| 101 | 02/13/92 | 00.03 | Baseline repeat, with air & water | 60 | B | 6.86 | 0.00 | 0 | 7.64 | 32 | 43 | 713 | 960 | 11.2 | 294 | 396 | 9 | 9 | 0 | - | 0.00 | 0.0 | - | - | 2 |
| 102 | 02/13/92 | 01.23 | 28 gpm liq, 8 psi air, N/NO-1.0 | 60 | B | 6.93 | 1.42 | 8 | 7.68 | 67 | 91 | 418 | 584 | 11.0 | - | - | 58 | 9 | 45 | 143 | 1.05 | 41.3 | 39.4 | 0.15 | 50 |
| 103 | 02/13/92 | 03.10 | 28 gpm liq, 8 psi air, N/NO-1.5 | 60 | B | 6.90 | 2.15 | 8 | 7.73 | 80 | 109 | 350 | 475 | 10.9 | 95 | 129 | 73 | 9 | 98 | - | 1.59 | 50.5 | 31.9 | 0.17 | 68 |
| 104 | 02/13/92 | 03.47 | 28 gpm liq, 8 psi air, N/NO-0.5 | 60 | B | 6.97 | 0.71 | 8 | 7.77 | 53 | 72 | 523 | 711 | 10.9 | 190 | 259 | 38 | 9 | 17 | - | 0.52 | 25.9 | 49.6 | 0.14 | 31 |
| 105 | 02/13/92 | 04.40 | Baseline repeat, with air & water | 60 | B | 6.94 | 0.00 | 8 | 7.80 | 32 | 44 | 695 | 948 | 10.9 | 290 | 395 | 9 | 9 | 0 | - | 0.00 | 0.0 | - | - | 3 |

PSCC Arapahoe Unit 4   Baseline/Urea Data Summary

| Test | Date & Time | Comments | Load MWe | Mills OOS | CRO2 % wet | Urea gpm | Air P psig | O2 % | CO ppm | COc ppm@3% | NO ppm | NOc ppm@3% | CO2 % | SO2 ppm | SO2c ppm@3% | N2O ppm | N2Oc ppm(1) | NH3 ppm(2) | NH3 ppm(3) | N/NO | ΔNO % | Utiliz. % | ΔN2O/ΔNOx | ΔCO ppm |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 106 | 02/13/92 14:04 | Baseline, Lvl 1, 1.5"air/.086"liq | 100 | | 4.07 | 0.00 | 0 | 4.85 | 37 | 41 | 788 | 878 | 13.9 | 358 | 399 | 9 | 9 | 0 | - | 0.00 | 0.0 | 0.0 | - | 0 |
| 107 | 02/13/92 14:16 | 28 gpm liq, 8 psi air, N/NO 0.5 | 100 | | 3.92 | 1.10 | 8 | 4.88 | 53 | 59 | 543 | 605 | 13.8 | 369 | 411 | 39 | 9 | 0 | 4 | 0.51 | 31.1 | 61.0 | 0.11 | 18 |
| 108 | 02/13/92 16:12 | 28 gpm liq, 8 psi air, N/NO 1.0 | 100 | | 3.98 | 2.20 | 8 | 5.13 | 66 | 75 | 430 | 488 | 13.7 | 358 | 406 | 60 | 9 | 2 | 20 | 1.02 | 44.4 | 43.6 | 0.13 | 34 |
| 109 | 02/13/92 17:16 | 28 gpm liq, 8 psi air, N/NO 1.5 | 100 | | 4.07 | 3.30 | 8 | 5.15 | 74 | 84 | 358 | 406 | 13.6 | 343 | 389 | 77 | 9 | 10 | 39 | 1.53 | 53.8 | 35.2 | 0.15 | 43 |
| 110 | 02/13/92 20:00 | 28 gpm liq, 12 psi air, N/NO 1.5 | 100 | | 4.38 | 3.30 | 12 | 5.40 | 80 | 92 | 320 | 369 | 13.6 | 305 | 352 | 83 | 9 | 11 | - | 1.53 | 58.0 | 37.9 | 0.15 | 51 |
| 111 | 02/13/92 20:40 | 28 gpm liq, 1.5 psi air, N/NO 1.5 | 100 | | 4.21 | 3.30 | 2 | 5.10 | 85 | 96 | 390 | 442 | 13.6 | 225 | 255 | 82 | 9 | 52 | - | 1.53 | 49.7 | 32.5 | 0.17 | 55 |
| 112 | 02/13/92 21:07 | Baseline repeat, with air & water | 100 | | | 0.00 | 2 | 5.10 | 37 | 42 | 820 | 928 | 13.7 | 330 | 374 | 9 | 9 | 6 | - | 0.00 | -5.7 | | 0.11 | 1 |
| 113 | 02/24/92 12:04 | Baseline, Lvl 1, 1.5"air/.059"liq | 101 | | 4.25 | 0.00 | 2 | 5.00 | 35 | 39 | 789 | 887 | 13.8 | 375 | 422 | 8 | 8 | - | - | 0.00 | 0.0 | - | - | 0 |
| 114 | 02/24/92 13:21 | Baseline, with air & water | 101 | | 4.27 | 0.00 | 8 | 5.20 | 33 | 38 | 770 | 878 | 13.6 | 360 | 410 | 9 | 8 | - | - | 0.00 | 1.0 | - | -0.14 | -1 |
| 115 | 02/24/92 14:30 | 9 gpm liq, 8 psi air, N/NO 1.0 | 101 | | 4.55 | 2.29 | 8 | 5.33 | 59 | 59 | 518 | 595 | 13.6 | 378 | 434 | 44 | 8 | 0 | - | 1.04 | 32.9 | 31.7 | 0.12 | 20 |
| 116 | 02/24/92 16:35 | 18 gpm liq, 8 psi air, N/NO 1.5 | 101 | | 4.59 | 3.40 | 8 | 5.36 | 64 | 74 | 415 | 478 | 13.5 | 361 | 416 | 66 | 8 | 19 | - | 1.54 | 46.1 | 29.9 | 0.14 | 35 |
| 116 | 02/24/92 16:50 | 116-1, NH3 Verif, Sintered Mil Fltr | 101 | | 4.59 | 3.40 | 8 | 5.35 | 65 | 75 | 410 | 472 | 13.5 | 360 | 414 | 65 | 8 | 18 | 7 | 1.54 | 46.8 | 30.3 | 0.14 | 36 |
| 116 | 02/24/92 17:10 | 116-2, NH3 Verif, Sintered Mil Fltr | 101 | | 4.59 | 3.40 | 8 | 5.40 | 63 | 73 | 415 | 479 | 13.5 | 365 | 421 | 65 | 8 | 23 | 6 | 1.54 | 46.0 | 29.8 | 0.14 | 34 |
| 116 | 02/24/92 17:29 | 116-3, NH3 Verif, Sintered Mil Fltr | 101 | | 4.59 | 3.40 | 8 | 5.40 | 63 | 73 | 420 | 485 | 13.5 | 360 | 416 | 65 | 8 | 17 | 7 | 1.54 | 45.3 | 29.4 | 0.15 | 34 |
| 117 | 02/25/92 08:12 | Baseline, Lvl 1, 1.5"air/.059"liq | 101 | | 4.18 | 0.00 | 0 | 4.93 | 36 | 40 | 775 | 868 | 13.9 | 338 | 378 | 8 | 8 | 0 | - | 0.00 | 0.0 | - | - | 0 |
| 118 | 02/25/92 09:35 | 18 gpm liq, 8 psi air, N/NO 0.5 | 100 | | 4.35 | 1.15 | 8 | 5.08 | 51 | 58 | 515 | 583 | 13.6 | 336 | 377 | 37 | 8 | 0 | 4 | 0.54 | 32.8 | 60.8 | 0.10 | 18 |
| 119 | 02/25/92 10:30 | 18 gpm liq, 8 psi air, N/NO 1.0 | 100 | | 4.28 | 2.30 | 8 | 4.98 | 62 | 70 | 394 | 443 | 13.8 | 336 | 378 | 59 | 8 | 28 | 26 | 1.08 | 49.0 | 45.3 | 0.13 | 30 |
| 120 | 02/25/92 11:20 | 18 gpm liq, 8 psi air, N/NO 1.5 | 100 | | 4.18 | 3.45 | 8 | 4.93 | 73 | 82 | 335 | 371 | 13.8 | 300 | 336 | 74 | 8 | 88 | 68 | 1.62 | 57.3 | 35.3 | 0.14 | 42 |
| 121 | 02/25/92 12:00 | Baseline repeat, with air & water | 101 | | 4.13 | 0.00 | 8 | 4.85 | 34 | 38 | 735 | 819 | 13.8 | 330 | 368 | 10 | 8 | 6 | - | 0.00 | 5.6 | - | -0.05 | -2 |
| 122 | 02/25/92 14:00 | Baseline repeat with air & water, | 100 | | 4.25 | 0.00 | 8 | 5.00 | 35 | 39 | 750 | 844 | 13.8 | 335 | 377 | 9 | 9 | 0 | - | 0.00 | 2.3 | - | -0.13 | -1 |
| | | Lvl 2,1.625"air/.049"liq | | | | | | | | | | | | | | | | | | | | | | |
| 123 | 02/25/92 14:35 | 5.5 gpm liq, 8 psi liq, N/NO 0.5 | 100 | B | 4.27 | 1.15 | 8 | 4.96 | 56 | 63 | 575 | 646 | 13.9 | 238 | 267 | 35 | 9 | 176 | 152 | 0.54 | 25.2 | 46.7 | 0.11 | 23 |
| 124 | 02/25/92 15:30 | Lvl 1, 9 gpm liq, 8 psi air, N/NO 0.5 | 100 | B | 4.15 | 1.15 | 8 | 4.90 | 48 | 54 | 533 | 596 | 13.9 | 335 | 375 | 36 | 9 | 7 | 7 | 0.54 | 31.0 | 57.4 | 0.10 | 14 |
| 125 | 02/25/92 16:30 | Lvl 1, 9 gpm liq, 8 psi air, N/NO 1.0 | 100 | B | 4.18 | 2.30 | 8 | 4.90 | 57 | 64 | 443 | 495 | 13.9 | 340 | 380 | 53 | 9 | 14 | 16 | 1.08 | 42.7 | 39.5 | 0.12 | 24 |
| 126 | 02/25/92 17:13 | Lvl 1, 9 gpm liq, 8 psi air, N/NO 1.5 | 100 | B | 4.22 | 3.40 | 8 | 5.00 | 62 | 70 | 405 | 456 | 13.8 | 330 | 371 | 62 | 9 | 37 | 32 | 1.60 | 47.2 | 29.6 | 0.13 | 30 |
| 127 | 02/25/92 17:50 | Baseline repeat | 100 | B | 4.18 | 0.00 | 0 | 4.85 | 35 | 39 | 775 | 864 | 13.9 | 330 | 368 | 9 | 9 | 4 | - | 0.00 | 0.0 | - | - | -1 |
| 128 | 02/26/92 08:48 | Baseline, Lvl 1, 1.5"air/.059"liq | 80 | B | 4.87 | 0.00 | 0 | 5.58 | 35 | 41 | 687 | 801 | 13.2 | 310 | 362 | 9 | 8 | 0 | - | 0.00 | 0.0 | - | - | 0 |
| 129 | 02/26/92 10:02 | Baseline repeat with air & water | 80 | B | 5.58 | 0.00 | 8 | 6.30 | 35 | 43 | 704 | 862 | 12.4 | 295 | 361 | 8 | 8 | 0 | - | 0.00 | -7.6 | - | 0.18 | 2 |
| 130 | 02/26/92 10:02 | 9 gpm liq, 8 psi air, N/NO 0.5 | 80 | B | 5.52 | 0.75 | 8 | 6.30 | 53 | 65 | 473 | 579 | 12.5 | 308 | 376 | 40 | 8 | 6 | - | 0.48 | 27.7 | 58.3 | 0.14 | 24 |
| 131 | 02/26/92 11:23 | 9 gpm liq, 8 psi air, N/NO 1.0, abort | 80 | B | 5.29 | 1.50 | 8 | 6.20 | 70 | 85 | 340 | | 12.7 | 285 | | 65 | 8 | - | - | 0.00 | 0.0 | 0.0 | 0.00 | 44 |
| 132 | 02/26/92 13:55 | Baseline, Lvl 1, 1.5"air/.046"liq | 80 | B | 5.13 | 0.00 | 0 | 5.93 | 33 | 39 | 713 | 851 | 12.9 | 303 | 361 | 8 | 8 | 0 | - | 0.00 | 0.0 | - | - | 1 |
| 133 | 02/26/92 15:08 | 7 gpm liq, 8 psi air, N/NO 0.5 | 80 | B | 5.41 | 0.72 | 8 | 6.25 | 52 | 64 | 489 | 597 | 12.6 | 304 | 371 | 40 | 8 | 6 | 11 | 0.42 | 29.8 | 70.5 | 0.13 | 26 |
| 134 | 02/26/92 15:49 | 7 gpm liq, 8 psi air, N/NO 1.0 | 79 | B | 5.43 | 1.50 | 8 | 6.20 | 68 | 83 | 350 | 426 | 12.7 | 285 | 347 | 64 | 8 | 45 | 55 | 0.89 | 49.9 | 55.9 | 0.14 | 45 |
| 135 | 02/26/92 16:30 | 7 gpm liq, 8 psi air, N/NO 1.5 | 79 | B | 5.81 | 2.20 | 8 | 6.60 | 75 | 94 | 303 | 378 | 12.4 | 235 | 294 | 79 | 8 | 81 | 91 | 1.29 | 57.8 | 44.9 | 0.16 | 56 |
| 136 | 02/26/92 17:10 | Baseline repeat | 79 | | 5.71 | 0.00 | 0 | 6.40 | 30 | 37 | 726 | 895 | 12.5 | 295 | 344 | 9 | 9 | 0 | - | 0.00 | 0.0 | - | - | -1 |
| 137 | 02/26/92 22:42 | Baseline, Lvl 1, 1.5"air/.046"liq | 61 | | 7.00 | 0.00 | 0 | 7.40 | 32 | 42 | 724 | 958 | 11.6 | 260 | 344 | 8 | 8 | 0 | - | 0.00 | 0.0 | - | - | 0 |
| 138 | 02/28/92 00:15 | Baseline repeat | 62 | | 6.29 | 0.00 | 0 | 6.88 | 32 | 41 | 678 | 864 | 12.1 | 274 | 349 | 39 | 8 | 0 | - | 0.00 | 0.0 | 0.0 | - | 0 |
| 139 | 02/28/92 01:07 | 7 gpm liq, 8 psi air, N/NO 0.5 | 62 | | 6.54 | 0.60 | 8 | 7.13 | 54 | 70 | 458 | 594 | 11.8 | 273 | 354 | 39 | 8 | 77 | 23 | 0.46 | 31.3 | 68.6 | 0.13 | 29 |
| 140 | 02/28/92 01:40 | 7 gpm liq, 8 psi air, N/NO 1.0 | 62 | | 6.58 | 1.20 | 8 | 7.20 | 70 | 91 | 346 | 452 | 11.7 | 228 | 297 | 62 | 8 | 77 | 90 | 0.91 | 47.7 | 52.3 | 0.15 | 50 |
| 141 | 02/28/92 02:22 | 7 gpm liq, 8 psi air, N/NO 1.5 | 62 | | 6.46 | 1.80 | 8 | 7.20 | 80 | 105 | 283 | 369 | 11.6 | 180 | 235 | 79 | 8 | 120 | 162 | 1.37 | 57.3 | 41.9 | 0.17 | 64 |
| 142 | 02/28/92 03:02 | N/NO 0.5, long-term repeat | 62 | | 6.50 | 0.60 | 8 | 7.15 | 53 | 69 | 465 | 604 | 11.8 | 248 | 322 | 40 | 8 | 31 | 37 | 0.46 | 30.1 | 66.0 | 0.13 | 28 |
| 142 | 02/28/92 03:42 | 142-2, NH3 Verif, Glass Wool Filter | 62 | | 6.50 | 0.60 | 8 | 7.15 | 51 | 66 | 470 | 611 | 11.8 | 265 | 344 | 39 | 8 | 28 | 5 | 0.46 | 29.3 | 64.3 | 0.13 | 25 |
| 142 | 02/28/92 04:02 | 142-3, NH3 Verif, Glass Wool Filter | 62 | | 6.50 | 0.60 | 8 | 7.15 | 51 | 66 | 470 | 611 | 11.7 | 263 | 342 | 37 | 8 | 28 | 5 | 0.46 | 29.3 | 64.3 | 0.12 | 25 |
| 142 | 02/28/92 04:27 | 142-4, NH3 Verif, No Filter | 62 | | 6.50 | 0.60 | 8 | 7.15 | 51 | 66 | 470 | 611 | 11.7 | 262 | 341 | 38 | 8 | 28 | 7 | 0.46 | 29.3 | 64.3 | 0.13 | 25 |
| 142 | 02/28/92 04:45 | 142-5, NH3 Verif, Sintered Mil Fltr | 62 | | 6.50 | 0.60 | 8 | 7.15 | 51 | 66 | 472 | 613 | 11.7 | 260 | 338 | 37 | 8 | 31 | 4 | 0.46 | 29.1 | 63.8 | 0.12 | 25 |
| 142 | 02/28/92 05:02 | 142-6, NH3 Verif, Sintered Mil Fltr | 62 | | 6.50 | 0.60 | 8 | 7.10 | 50 | 65 | 480 | 622 | 11.8 | 262 | 339 | 37 | 8 | 33 | 5 | 0.46 | 28.0 | 61.5 | 0.13 | 24 |
| 143 | 02/28/92 07:40 | Baseline, Lvl 1, 1.5"air/.046"liq | 100 | | 3.87 | 0.00 | 0 | 4.68 | 36 | 40 | 745 | 822 | 14.2 | 333 | 367 | 8 | 8 | 0 | - | 0.00 | 0.0 | - | - | 0 |
| 144 | 02/28/92 08:55 | 19 gpm liq, 8 psi air, N/NO 0.5 | 99 | | 4.27 | 2.05 | 8 | 5.15 | 61 | 69 | 420 | 477 | 13.6 | 320 | 363 | 55 | 8 | 9 | - | 0.95 | 46.6 | 49.0 | 0.12 | 29 |
| 145 | 02/28/92 09:20 | 16 gpm liq, 8 psi air, N/NO 1.0 | 98 | | 4.00 | 2.05 | 8 | 5.15 | 59 | 67 | 425 | 483 | 13.6 | 315 | 358 | 54 | 8 | 10 | 7 | 0.96 | 46.0 | 47.8 | 0.11 | 27 |
| 146 | 02/28/92 09:37 | 13 gpm liq, 8 psi air, N/NO 1.0 | 99 | | 4.03 | 2.05 | 8 | 5.15 | 55 | 63 | 445 | 505 | 13.6 | 320 | 363 | 49 | 8 | 6 | - | 0.95 | 43.5 | 45.7 | 0.11 | 23 |
| 147 | 02/28/92 09:50 | 10 gpm liq, 8 psi air, N/NO 1.0 | 99 | | 4.15 | 2.05 | 8 | 5.20 | 53 | 60 | 462 | 526 | 13.5 | 318 | 362 | 45 | 8 | 4 | - | 0.95 | 41.2 | 43.3 | 0.10 | 20 |
| 148 | 02/28/92 10:10 | 7 gpm liq, 8 psi air, N/NO 1.0 | 99 | | 4.15 | 2.05 | 8 | 5.35 | 50 | 58 | 500 | 575 | 13.3 | 315 | 362 | 40 | 8 | 1 | 8 | 0.95 | 35.7 | 37.5 | 0.10 | 18 |
| 149 | 02/28/92 10:50 | 7 gpm liq, 8 psi air, N/NO 1.0 | 99 | | 4.32 | 2.05 | 8 | 5.25 | 51 | 58 | 510 | 575 | 13.5 | 311 | 356 | 42 | 8 | 0 | 8 | 0.95 | 34.8 | 36.6 | 0.11 | 18 |
| 150 | 02/28/92 11:25 | 7 gpm liq, 8 psi air, N/NO 0.5 | 99 | | 4.25 | 1.10 | 8 | 5.20 | 43 | 49 | 583 | 664 | 13.5 | 315 | 359 | 28 | 8 | 0 | 3 | 0.51 | 25.7 | 50.4 | 0.07 | 9 |
| 151 | 02/28/92 12:00 | 7 gpm liq, 8 psi air, N/NO 1.5 | 99 | | 4.15 | 3.10 | 8 | 5.25 | 55 | 63 | 473 | 540 | 13.6 | 305 | 349 | 49 | 8 | 1 | 15 | 1.44 | 39.6 | 27.5 | 0.11 | 23 |
| 152 | 02/28/92 12:50 | 7 gpm liq, 8 psi air, N/NO 2.0 | 99 | | 4.10 | 4.10 | 8 | 5.20 | 58 | 66 | 455 | 518 | 13.5 | 295 | 336 | 54 | 8 | 6 | - | 1.90 | 42.1 | 22.1 | 0.12 | 26 |

PSOC Arapahoe Unit 4   Baseline/Urea Data Summary

| Test | Date | Time | Comments | Load MWe | Mills OOS | CH O2 % wet | Urea gpm | Air P psig | O2 % | CO ppm | COc ppm@3% | NO ppm | NOc ppm@3% | CO2 % | SO2 ppm | SO2c ppm@3% | N2O ppm | N2Oc ppm(1) | NH3 ppm(2) | NH3 ppm(3) | N/NO | NNO % | Utiliz % | ΔN2O/ΔNOx | ΔCO ppm |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 153 | 02/28/92 | 13:10 | Baseline repeat | 99 | | 3.95 | 0.00 | 0 | 5.00 | 35 | 39 | 795 | 894 | 13.7 | 310 | 349 | 8 | 8 | 1 | - | 0.00 | 0.0 | - | - | -1 |
| 154 | 02/28/92 | 14:53 | Baseline, Lvl 1, 1.5"air/.046"liq | 99 | B | 3.97 | 0.00 | 0 | 4.80 | 35 | 39 | 838 | 931 | 14.0 | 318 | 353 | 8 | 8 | 0 | - | 0.00 | 0.0 | - | - | 0 |
| 155 | 02/28/92 | 15:40 | 16 gpm liq, 8 psi air, N/NO-1.0 | 99 | B | 4.00 | 2.30 | 8 | 4.95 | 63 | 71 | 460 | 516 | 13.8 | 323 | 362 | 59 | 8 | 5 | 15 | 1.02 | 44.6 | 43.9 | 0.12 | 32 |
| 156 | 02/28/92 | 16:35 | 10 gpm liq, 8 psi air, N/NO-1.0 | 99 | B | 4.05 | 2.30 | 8 | 5.08 | 58 | 66 | 505 | 571 | 13.7 | 320 | 362 | 53 | 8 | 4 | 11 | 1.02 | 38.7 | 38.1 | 0.12 | 27 |
| 157 | 03/03/92 | 09:26 | Baseline, Lvl 1, 1.5"air/.046"liq | 101 | | 3.85 | 0.00 | 0 | 4.70 | 35 | 39 | 784 | 868 | 14.1 | 424 | 469 | 9 | 9 | 0 | - | 0.00 | 0.0 | - | - | 1 |
| 158 | 03/03/92 | 10:41 | 16 gpm liq, 8 psi air, N/NO-1.0 | 100 | | 3.58 | 2.20 | 8 | 4.00 | 60 | 64 | 427 | 470 | 14.0 | 433 | 477 | 50 | 9 | 3 | 8 | 1.04 | 45.9 | 44.2 | 0.11 | 26 |
| 158 | 03/03/92 | 11:54 | Same, Start NH3 Samples at Stack | 100 | | 3.58 | 2.20 | 8 | 4.00 | 60 | 64 | 427 | 470 | 14.0 | 433 | 477 | 50 | 9 | 3 | 0.6 stk | 1.04 | 45.9 | 44.2 | 0.11 | 26 |
| 159 | 03/03/92 | 13:00 | 16 gpm liq, 8 psi air, N/NO-1.0 | 101 | | 3.58 | 2.20 | 8 | 4.30 | 63 | 68 | 406 | 437 | 14.4 | 445 | 479 | 55 | 9 | 12 | 2.7 stk | 1.03 | 49.7 | 48.3 | 0.11 | 30 |
| 160 | 03/03/92 | 14:00 | 16 gpm liq, 8 psi air, N/NO-1.0 | 100 | | 3.35 | 2.20 | 8 | 4.60 | 66 | 72 | 419 | 453 | 14.4 | 459 | 496 | 51 | 9 | 19 | 7.8 stk | 1.04 | 47.8 | 46.1 | 0.11 | 34 |
| 161 | 03/03/92 | 15:00 | 16 gpm liq, 8 psi air, N/NO-1.0 | 100 | | 3.68 | 2.20 | 8 | 4.60 | 60 | 66 | 496 | 478 | 14.2 | 457 | 500 | 49 | 9 | 10 | 7.3 stk | 1.04 | 44.2 | 42.5 | 0.13 | 28 |
| 162 | 03/03/92 | 16:00 | 16 gpm liq, 8 psi air, N/NO-1.0 | 100 | | 3.83 | 2.20 | 8 | 4.60 | 61 | 67 | 438 | 480 | 14.1 | 446 | 489 | 46 | 9 | 10 | 7.1 stk | 1.04 | 44.0 | 42.2 | 0.10 | 29 |
| 163 | 03/03/92 | 17:15 | 16 gpm liq, 8 psi air, N/NO-1.0 | 100 | | 3.68 | 2.20 | 8 | 4.40 | 60 | 65 | 455 | 493 | 14.1 | 444 | 481 | 50 | 9 | 10 | - | 1.04 | 42.5 | 40.8 | 0.12 | 27 |
| 164 | 03/03/92 | 17:25 | Baseline repeat | 100 | | 3.65 | 0.00 | 0 | 4.60 | 34 | 37 | 781 | 857 | 14.1 | 448 | 491 | 9 | 9 | 1 | - | 0.00 | 0.0 | - | - | -1 |
| 165 | 03/04/92 | 17:00 | Baseline, Lvl 1, 1.5"air/.046"liq | 99 | | 3.87 | 0.00 | 0 | 5.00 | 35 | 39 | 780 | 867 | 13.8 | 335 | 376 | 9 | 9 | - | - | 0.00 | 0.0 | - | - | 0 |
| 166 | 03/04/92 | 19:45 | NH4OH, 7 gpm liq, 8 psi, N/NO 0.5 | 99 | | 4.11 | 2.10 | 8 | 4.90 | 38 | 43 | 620 | 693 | 13.9 | 340 | 381 | 11 | 9 | - | 0 | 0.51 | 20.1 | 39.4 | -0.01 | 4 |
| 167 | 03/04/92 | 20:35 | NH4OH, 7 gpm liq, 8 psi, N/NO-1.0 | 99 | | 4.05 | 4.10 | 8 | 4.95 | 43 | 48 | 578 | 648 | 13.9 | 340 | 382 | 12 | 9 | - | 0 | 0.99 | 25.3 | 25.4 | 0.00 | 9 |
| 168 | 03/04/92 | 22:41 | NH4OH, 7 gpm liq, 8 psi, N/NO-1.4 | 99 | | 4.28 | 5.80 | 8 | 4.80 | 45 | 50 | 520 | 577 | 13.7 | 340 | 378 | 16 | 9 | - | 5 | 1.41 | 33.4 | 23.8 | 0.02 | 11 |
| 169 | 03/04/92 | 23:50 | NH4OH, 18 gpm liq, 8 psi, N/NO-0.5 | 99 | | 4.17 | 2.20 | 8 | 5.00 | 40 | 45 | 563 | 633 | 13.8 | 343 | 386 | 13 | 9 | - | 1 | 0.54 | 26.7 | 49.0 | 0.00 | 6 |
| 170 | 03/05/92 | 00:37 | NH4OH, 18 gpm liq, 8 psi, N/NO-1.0 | 100 | | 4.43 | 4.10 | 8 | 5.20 | 36 | 41 | 523 | 595 | 13.6 | 343 | 390 | 15 | 9 | - | 1 | 1.00 | 31.1 | 30.9 | 0.01 | 2 |
| 171 | 03/05/92 | 01:25 | NH4OH, 18 gpm liq, 8 psi, N/NO-1.4 | 100 | | 4.30 | 5.80 | 8 | 5.00 | 38 | 43 | 483 | 544 | 13.4 | 344 | 387 | 17 | 9 | - | 4 | 1.42 | 37.0 | 26.0 | 0.02 | 4 |
| 172 | 03/05/92 | 02:40 | Baseline repeat | 100 | | 3.98 | 0.00 | 0 | 5.10 | 63 | 71 | 765 | 863 | 13.8 | 338 | 381 | 9 | 9 | - | - | 0.00 | 0.0 | - | - | 32 |
| 173 | 03/05/92 | 15:15 | Baseline, Aborted, Feeder Problems | 80 | | 4.96 | 0.00 | 0 | 5.55 | 40 | 47 | 630 | 734 | 13.3 | 320 | 373 | 10 | 10 | - | - | 0.00 | 0.0 | - | - | 0 |
| 174 | 03/05/92 | 16:06 | Baseline, Lvl 1, 1.5"air/.046"liq | 80 | | 5.04 | 0.00 | 0 | 5.75 | 30 | 35 | 725 | 856 | 13.0 | 325 | 384 | 9 | 9 | - | - | 0.00 | 0.0 | - | - | 0 |
| 175 | 03/05/92 | 17:14 | NH4OH, 7 gpm liq, 8 psi, N/NO 0.5 | 80 | | 5.21 | 1.50 | 8 | 6.18 | 33 | 40 | 524 | 636 | 12.8 | 330 | 401 | 12 | 9 | - | 1 | 0.46 | 25.7 | 55.5 | 0.00 | 5 |
| 176 | 03/06/92 | 01:10 | Baseline, Lvl 1, 1.5"air/.046"liq | 61 | B | 6.24 | 0.00 | 0 | 6.60 | 32 | 40 | 696 | 870 | 12.3 | 313 | 391 | 8 | 8 | - | - | 0.00 | 0.0 | - | - | 0 |
| 177 | 03/06/92 | 02:00 | NH4OH, 7 gpm liq, 8 psi, N/NO-0.5 | 61 | B | 6.02 | 1.20 | 8 | 6.65 | 35 | 44 | 434 | 544 | 12.3 | 314 | 393 | 13 | 8 | - | 15 | 0.48 | 37.5 | 78.1 | 0.00 | 4 |
| 178 | 03/06/92 | 02:30 | NH4OH, 7 gpm liq, 8 psi, N/NO-1.0 | 61 | B | 5.78 | 2.40 | 8 | 6.48 | 40 | 50 | 318 | 394 | 12.4 | 285 | 354 | 18 | 8 | - | 46 | 0.96 | 54.7 | 57.0 | 0.02 | 10 |
| 179 | 03/06/92 | 03:12 | NH4OH, 7 gpm liq, 8 psi, N/NO-1.5 | 61 | B | 5.97 | 3.60 | 8 | 6.72 | 42 | 53 | 254 | 320 | 12.2 | 251 | 317 | 22 | 8 | - | 179 | 1.44 | 63.2 | 43.9 | 0.02 | 13 |
| 180 | 03/06/92 | 03:48 | NH4OH, 7 gpm liq, 8 psi, N/NO-2.0 | 61 | B | 5.85 | 4.80 | 8 | 6.80 | 45 | 57 | 210 | 266 | 12.2 | 208 | 263 | 27 | 8 | - | 263 | 1.92 | 69.4 | 36.2 | 0.03 | 17 |
| 181 | 03/06/92 | 04:31 | Baseline repeat | 61 | B | 5.71 | 0.00 | 0 | 6.50 | 33 | 41 | 687 | 853 | 12.4 | 265 | 329 | 9 | 9 | 1 | - | 0.00 | 0.0 | - | - | 1 |

(1): Data Corrected for CO2 Interference on NDIR Analyzer
(2): Continuous NH3 Analyzer
(3): Wet Chemical Composite Data