ENHANCING THE USE OF COALS BY GAS REBURNING - SORBENT INJECTION

Volume 1
Program Overview

Part A.
Public Design

Part B.
Project Performance and Economics

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Prepared by:

Energy and Environmental Research Corporation
18 Mason — 1345 N. Main Street
Irvine, CA 92718 — Orrville, OH 44667

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ABSTRACT

Under the U.S. Department of Energy's Clean Coal Technology Program (Round 1), a project was completed to demonstrate control of boiler emissions that comprise acid rain precursors, specifically oxides of nitrogen (NO_x) and sulfur dioxide (SO_2). Other project sponsors were the Gas Research Institute and the Illinois State Department of Commerce and Community Affairs.

The project involved demonstrating the combined use of Gas Reburning and Sorbent Injection (GR-SI) to assess the air emissions reduction potential of these technologies.. Three potential coal-fired utility boiler host sites were evaluated: Illinois Power's tangentially-fired 71 MWe (net) Hennepin Unit #1, City Water Light and Power's cyclone-fired 33 MWe (gross) Lakeside Unit #7, and Central Illinois Light Company's wall-fired 117 MWe (net) Edwards Unit #1. Commercial demonstrations were completed on the Hennepin and Lakeside Units. The Edwards Unit was removed from consideration for a site demonstration due to retrofit cost considerations.

Gas Reburning (GR) controls air emissions of NO_x. Natural gas is introduced into the furnace hot flue gas creating a reducing reburning zone to convert NO_x to diatomic nitrogen (N_2). Overfire air is injected into the furnace above the reburning zone to complete the combustion of the reducing (fuel) gases created in the reburning zone. Sorbent Injection (SI) consists of the injection of dry, calcium-based sorbents into furnace hot flue gas to achieve SO_2 capture.

At each site where the technologies were to be demonstrated, performance goals were set to achieve air emission reductions of 60 percent for NO_x and 50 percent for SO_2. These performance goals were exceeded during long term demonstration testing. For the tangentially fired unit, NO_x emissions were reduced by 67.2% and SO_2 emissions by 52.6%. For the cyclone-fired unit, NO_x emissions were reduced by 62.9% and SO_2 emissions by 57.9%.

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City Water, Light and Power's Lakeside Station, especially Mr. Tom Booker
Central Illinois Light Company

POINTS OF CONTACT

For more information regarding **Gas Reburning (GR)** and **Sorbent Injection (SI)** technologies, please contact:

Dr. Blair A. Folsom
Senior Vice President
Energy and Environmental Research Corporation
18 Mason
Irvine, CA 92718
Phone (714) 859-8851
Fax (714) 859-3194

or

Mr. Todd M. Sommer
Vice President
Energy and Environmental Research Corporation
1345 N. Main St.
Orrville, OH 44667
Phone (216) 682-4007
Fax (216) 684-2110

AUTHORS

The following EER personnel contributed in the preparation of this report:

Robert A. Ashworth

Rafik Z. Beshai

Donald A. Engelhardt

Blair A. Folsom

Roy Payne

Todd M. Sommer

LIST OF ABBREVIATIONS

ASME	American Society of Mechanical Engineering
ASME.PTC	ASME Performance Test Code
ASTM	American Society of Testing Materials
B&W	Babcock and Wilcox
BL	Baseline
BPMS	Boiler Performance Monitoring System
BSF	Boiler Simulator Furnace
CAAA	Clean Air Act Amendments
CCT	Clean Coal Technology
CE	Combustion Engineering
CEMS	Continuous Emissions Monitoring System
CILCO	Central Illinois Light Company
CF	Cleanliness Factor
CFLW	Coal Flow
CFR	Code of Federal Regulations
CRH	Cold Reheater
CTA	Coal Theoretical Air
CWLP	City Water Light and Power
DCCA	Department of Commerce and Community Affairs (Illinois)
DOE	United States Department of Energy
EA	Excess Air
EER	Energy and Environmental Research Corporation
EHSS	Environmental Health Safety and Socioeconomic
EIV	Environmental Information Volume
EMP	Environmental Monitoring Plan
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
FGR	Flue Gas Recirculation
FP	Flag Point
FSI	Furnace Sorbent Injection
GFLW	Gas Flow
GR	Gas Reburning
GRI	Gas Research Institute
GR-PS	Gas Reburning-Promoted Sorbent
GR-SI	Gas Reburning-Sorbent Injection
GTA	Gas Theoretical Air
HAR	Heat Absorption Ratio
HHV	Higher Heating Value
HSAHL	High Surface Area Hydrated Lime
IEPA	Illinois Environmental Protection Agency
IP	Illinois Power Company
ISGS	Illinois State Geological Survey

LIST OF ABBREVIATIONS (CONTINUED)

LOI	Loss on Ignition
MDL	Method Detection Limit
MGD	Million Gallon per Day
MFR	Manufacturer
MMD	Mass Mean Diameter
ND	Not Detected
NG	Natural Gas
NPDES	National Pollution Discharge Elimination System
NSPS	New Source Performance Standards
OEM	Original Equipment Manufacturer
OFA	Overfire Air
OSHA	Occupational Safety and Health Administration
PS	Promoted Sorbent
PSD	Prevention of Significant Deterioration
PSH	Primary Superheater
PTC	Performance Test Code
QAMS	Quality Assurance Management Staff
QAO	Quality Assurance Officer
QAPP	Quality Assurance Project Plan
QA/QC	Quality Assurance/Quality Control
RCRA	Resource Conservation and Recovery Act
RH	Reheat
SCA	Specific Collection Area
SH	Superheat
SI	Sorbent Injection
SMD	Sauter Mean Diameter
SR	Stoichiometric Ratio
TAFLW	Total Air Flow
TDS	Total Dissolved Solids
TPI	Total Plant Investment
TSP	Total Suspended Particles
TSS	Total Suspended Solids
U.S. EPA	United States Environmental Protection Agency
UT	Ultrasonic Thickness

LIST OF UNITS

acf	Actual Cubic Foot
acfm	Actual Cubic Foot per Minute
Btu/hr ft^3	British Thermal Unit per Hour per Cubic Foot
Btu/kWh	British Thermal Unit per Kilowatt-Hour
Btu/scf	British Thermal Unit per Standard Cubic Foot
°C	Degree Celsius
cm	Centimeter
db	Decibel
dscfm	Dry Standard Cubic Foot per Minute
°F	Degree Fahrenheit
ft^2	Square Foot
ft^2/1000 acfm	Square Foot per Thousand Actual Cubic Feet per Minute
ft^3	Cubic Foot
ft/s	Foot per Second
g	Gram
g/s	Gram per Second
g/cm^3	Gram per Cubic Centimeter
g/dNM^3	Gram per Dry Normal Cubic Meter
gpm	Gallon per Minute
gr/dscf	Grain per Dry Standard Cubic Foot
hp	Horsepower
hr	Hour
in	Inch
kg/m^3	Kilogram per Cubic Meter
kg/s	Kilogram per Second
kJ/kWh	Kilojoule per Kilowatt-Hour
klb/hr	Thousand Pounds per Hour
kPa	Kilopascal
KVA	Kilovolt-Ampere
kVDC	Kilovolt Direct Current
kW	Kilowatt
lb/ft^3	Pound per Cubic Foot
lb/hr	Pound per Hour
lb/min	Pound per Minute
lb/10^6 Btu	Pound per Million British Thermal Units
l/s	Liter per Second
$\mu g/m^3$	Microgram per Cubic Meter
m	Meter
m^2	Square Meter
$m^2/m^3/s$	Square Meter per Cubic Meter per Second
m/s	Meter per Second

mA	Milliampere
10^6 Btu/hr	Million British Thermal Units per Hour

LIST OF UNITS (CONTINUED)

MGD	Million Gallons per Day
mg/l	Milligram per Liter
mg/m^3	Milligram per Cubic Meter
mg/MJ	Milligram per Megajoule
mil	One thousandth of an Inch
MJ/s	Megajoule per Second
mld	Megaliter per Day
mm	Millimeter
MWe	Megawatt Electric
Nm^3/s	Normal Cubic Meter per Second
10^6 SCF	Million Standard Cubic Feet
ohm-cm	Ohm-Centimeter
psig	Pound per Square Inch (Gauge)
ppm	Parts per Million
scfh	Standard Cubic Foot per Hour
scf/lb	Standard Cubic Foot per Pound
scfm	Standard Cubic Foot per Minute
scf/scf	Standard Cubic Foot per Standard Cubic Foot
ton/yr	Ton per Year
tonne/a	Metric Ton per Year
V	Volt
W.C.	Water Column
'	Foot
"	Inch
%	Percent

GLOSSARY OF TERMS

Chemical Symbols:

Ag	Silver
Al_2O_3	Aluminum Oxide (Alumina)
As	Arsenic
B	Boron
BaO	Barium Oxide
C	Carbon
Ca	Calcium
$CaCO_3$	Calcium Carbonate
$CaCl_2$	Calcium Chloride
CaF_2	Calcium Fluoride
CaO	Calcium Oxide
$Ca(OH)_2$	Calcium Hydroxide
Ca/S	Sorbent Calcium to Coal Sulfur Molar Ratio
$CaSO_3$	Calcium Sulfite
$CaSO_4$	Calcium Sulfate
Cd	Cadmium
CH_4	Methane
C_2H_6	Ethane
C_3H_8	Propane
C_4H_{10}	Butane
C_5H_{10}	Pentane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
Cr	Chromium
Fe	Iron
Fe_2O_3	Ferric Oxide
H_2	Hydrogen (Diatomic)
HC	Hydrocarbon
HCl	Hydrogen Chloride
HF	Hydrogen Fluoride
Hg	Mercury
H_2S	Hydrogen Sulfide
H_2O	Water
MgO	Magnesium Oxide
$Mg(OH)_2$	Magnesium Hydroxide
MnO_2	Manganese Oxide
N_2	Nitrogen (Diatomic)
NO_x	Nitrogen Oxides
NO	Nitric Oxide (Colorless Gas)
NO_2	Nitrogen Dioxide (Reddish Brown Gas)

Chemical Symbols:

N_2O	Nitrous Oxide (Colorless Gas)
Pb	Lead
P_2O_5	Phosphorous Pentoxide
O_2	Oxygen (Diatomic)
O_3	Ozone
S	Sulfur
SiO_2	Silicon Dioxide (Silica)
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SrO	Strontium Oxide
SO_2	Sulfur Dioxide

EXECUTIVE SUMMARY

As part of the U.S. Department of Energy's Clean Coal Technology Program (Round 1), a project was completed to demonstrate control of boiler emissions that comprise acid rain precursors, specifically NO_x and SO_2. The project involved operating combined gas reburning and sorbent injection (GR-SI) on two coal-fired utility boilers to determine the reductions in these boiler emissions. Gas reburning (GR) controls the emissions of NO_x by staged fuel combustion, which involves the introduction of natural gas into the flue gas stream. Sorbent injection (SI) consists of the injection of dry, calcium-based sorbents into the flue gas to achieve SO_2 capture. Several benefits are derived from utilization of the combined GR-SI technologies including the following:

- Low capital cost relative to more expensive scrubbers
- Compatibility with high-sulfur coal
- No adverse effects on boiler thermal performance
- Minimal system operating complexity

The first demonstration was performed at Illinois Power's Hennepin Unit 1, located in Hennepin, Illinois. This unit is a 71 MWe tangentially-fired boiler that uses high-sulfur Illinois coal. The second test was performed at City Water Light & Power's (CWLP) Lakeside Unit No. 7, located in Springfield, Illinois. This unit is a 33 MWe cyclone-fired boiler that also uses high-sulfur Illinois coal. Targets for the project at both sites were reductions of 60 percent in NO_x emissions and 50 percent in SO_2 emissions. The initial format of the project involved three sites, the two described above and Central Illinois Light Company's Edwards Station Unit 1. During Phase I, it was determined that the cost to upgrade the Edwards electrostatic precipitator to accommodate SI was beyond the scope of the project budget. Therefore, the Edwards site was eliminated from further activity.

Gas Reburning

GR involves reducing the levels of coal and combustion air in the burner area and injecting natural gas above the burners followed by the injection of overfire air (OFA) above the reburning zone. This three-zone process creates a reducing area in the boiler furnace within which NO_x created in the primary zone is reduced to elemental nitrogen and other less harmful nitrogen species. Each zone has a unique stoichiometric ratio (ratio of air to that theoretically required for complete combustion) as determined by the flow of coal, burner air, natural gas, and OFA. Flue gas recirculation (FGR) may be used to provide momentum to the natural gas injection. Although FGR has a low O_2 content, it also has a minor impact on reburning and burnout zone stoichiometries. The descriptions of the zones are as follows:

- Primary (burner) Zone: Coal is fired at a rate corresponding to 75 to 90 percent of the total heat input, under low excess air. NO_x created in this zone is limited by the lower heat release and the reduced excess air level.
- Reburning Zone: Reburning fuel (natural gas in this case) injection creates a fuel rich region within which methane breaks down to hydrocarbon fragments (CH, CH_2, etc.) which react with NO_x, reducing it to atmospheric nitrogen. The optimum reburning zone stoichiometry is 0.90, achieved by injecting natural gas at a rate corresponding to 10 to 25 percent of the total heat input.
- Burnout (exit) Zone: OFA is injected higher up in the furnace to complete the combustion. OFA is typically 20 percent of the total air flow; a minimum excess air of 15 percent in maintained. OFA injection is optimized to minimize CO emissions and unburned carbon-in-fly ash.

Sorbent Injection

SI technology controls SO_2 emissions through injection of a calcium-based sorbent such as hydrated lime [$Ca(OH_2)$] into the boiler furnace where it reacts with gaseous SO_2 to form solid calcium sulfate. This compound is then removed from the flue gas in the electrostatic precipitator.

Sorbent is transported from a storage silo to the boiler and introduced into the flue gas through injection nozzles. A flow splitter in the sorbent line equally distributes the sorbent to the nozzles. To obtain the optimum sorbent mass flow and nozzle velocities required for adequate boiler dispersion, additional injection air is provided from a booster fan.

Integration of Gas Reburning and Sorbent Injection

GR and SI are applied simultaneously to achieve combined NO_x and SO_2 control. Although significantly reducing the NO_x emissions, GR also achieves an incremental reduction in SO_2 emissions, since natural gas contains no sulfur. This complements the SO_2 reduction of the SI process and reduces the amount of sorbent otherwise required.

Project Schedule and Status

The project was divided into the following three phases:

- Phase I — Design and Permitting
- Phase II — Construction and Startup
- Phase III — Operation, Data Collection, Reporting and Disposition

The project was awarded in July, 1987. Phase I activity for the three sites was perform concurrently; however, both construction and testing at Lakeside lagged that at Hennepin in order to transfer experience from site to site. Following parametric/optimization testing, a one-year test program was conducted at each site to assess the long term boiler impacts of the technology. The GR system at Hennepin was retained by Illinois Power. Both the GR and SI systems at Lakeside were retained by CWLP. None of the equipment is currently in operation.

Process Design

The process design was performed during Phase I of the Project. The goal in the design of the GR-SI system was to achieve the emissions control objectives while minimizing impacts on other areas of unit performance. Using NO_x reduction and sorbent sulfation reaction modeling and isothermal physical flow modeling, the process stream inputs and injection details of the GR-SI system were finalized. Heat transfer modeling was then conducted to predict the impacts on heat absorptions by each heat exchanger and steam side and gas side temperatures. Also evaluated were the potential effects on various areas of boiler performance including fuel burnout, furnace slagging, waterwall wastage, and ESP performance. As a result of the process design effort, the following parameters were established:

- Natural gas, OFA and sorbent injector sizes, required numbers, and boiler locations.
- Volume flow rates for natural gas, FGR, OFA, sorbent, and SI air.
- FGR and SI air fan specifications.
- Initial operating set-points for optimum boiler stoichiometries.

At each of the two demonstration sites, special design considerations were required to handle unique conditions in the boiler. At Illinois Power's tangentially-fired unit, humidification of the exit flue gas was required in order to raise the resistivity of the fly ash, thereby improving the efficiency of the electrostatic precipitator. Also, a CO_2 system was installed to adjust the pH of the ash prior to its discharge into the collection pond.

CWLP's cyclone-fired boiler operates in a pressurized environment requiring check valves in the natural gas, sorbent and injection air ducts to prevent backflow of flue gas. Sealing air was also integrated with boiler penetration equipment. Due to the age of the sootblowers and wallblowers and the anticipated increase in use, this equipment was replaced. CWLP's ash pond was nearing capacity; therefore, a dry ash handling system was installed to provide for off-site removal.

Installation and Integration

The GR-SI system was installed during Phase II of the Project. The GR system retrofit involved routing a natural gas main to the boiler, installing a FGR fan, installing a multiclone dust collector to remove particulate and protect the fan, and connecting the equipment with ductwork. The OFA system involved installation of ductwork from the secondary air system to the injection nozzles. The SI system included a sorbent storage silo, feed equipment and transport system. Penetration of the sorbent into the boiler was enhanced by installing an injection air fan system. An extensive plant outage was required to install boiler penetrations. Some outage time was also required to install the control system.

Integration of the GR-SI system into normal boiler operations required modification and/or replacement of the existing control system. The new control system was designed to accommodate several operating conditions including GR, SI, combined GR-SI, non-operation of either system, and operation of site-specific additional equipment.

Test Plan and Testing

Phase III of the Project was devoted to demonstration of the technology. Following startup, a series of pre-planned parametric tests were performed independently on the GR and SI systems. These tests were conducted at different boiler load conditions and involved varying operational control parameters (such as boiler zone stoichiometries, natural gas heat input, FGR flow rate, OFA flow rate, sorbent feed rate, etc.) and assessing the effect on boiler emissions and thermal efficiency. Following the parametric testing, the technologies were integrated through a series of optimization tests, incorporating the set points established in the parametric tests. Final adjustments to the control parameters were made as required.

A one-year duration long term testing program was performed at each site in order to judge the consistency of system outputs, assess the impact of long-term operation on the boiler equipment, gain experience in operating GR-SI in a normal load-following environment, and develop a database for use in subsequent GR-SI applications. The project concluded with a test of alternate sorbent material.

Emissions Testing

EER conducted a comprehensive test demonstration program at each of the two sites, operating the equipment over a wide range of boiler conditions. Over 1500 hours of operation were achieved enabling EER to obtain a substantial amount of data. Extensive measurements were taken to quantify the reductions in NO_x and SO_2 emissions, the impact on boiler equipment and operability, and all factors influencing costs. The judgment is that GR-SI technology achieved excellent emissions reductions on both tangentially-fired and cyclone-fired boilers; all goals of the project phase were achieved. The following table summarizes the results of the combined GR-SI operation:

	Tangential	Cyclone
NO_x emissions		
baseline	.75 lb/10^6 Btu	.95 lb/10^6 Btu
optimized reduction	75%	74%
average reduction	67%	63%
average gas heat input	18%	22%
SO_2 emissions (w/GR-SI)		
baseline	5.3 lb/10^6 Btu	5.9 lb/10^6 Btu
average reduction	55.3%	55.7%
calcium-to-sulfur ratio	1.75	1.8
calcium utilization	26%	24%

NO_x decreased as the reburning gas heat input increased. Also, the performance goal (reduction of NO_x emissions by 60%) on both units was consistently met throughout the test program.

A higher gas heat input is required for the cyclone-fired boiler than the tangentially-fired boiler. On the T-fired boiler, the stoichiometry in the firing zone is reduced to promote reduction in NO_x emissions. This method is not the applicable to cyclone-fired boilers since reducing the stoichiometry disrupts the slagging characteristics of the cyclone. Therefore, a higher gas heat input was required to achieve the same NO_x emissions reduction. Other factors remained approximately the same.

The GR systems for these units used FGR to enhance the penetration and mixing of the reburning gas. While high velocity gas jets could have been used instead of FGR, FGR was selected as the more conservative approach for these initial demonstrations since the penetration and mixing are controlled by the FGR flow rate essentially independent of the natural gas flow rate. However, FGR adds substantially to the capital cost of the GR system and also contributes slightly to the increased superheat attemperation rate.

SO_2 emissions improved with higher Ca/S. Also, the performance goal (reduction of SO_2 emissions by 50%) at both units was consistently met throughout the test program. The Lakeside unit experienced a higher SO_2 emissions reduction than the Hennepin unit due to a higher level of gas heat input. Higher levels of Ca/S were required at lower loads due the effect of temperature on the sulfation reaction. Bench tests showed that a temperature 2200°F was optimum to achieve the maximum SO_2 emissions reduction. This temperature was observed in the sulfation zone during full load, but was somewhat less at lower loads.

The GR-SI demonstration was conducted primarily with conventional sorbent, Linwood hydrated lime. At the conclusion of the long term testing, three advanced sorbents prepared by EER and the Illinois State Geological Survey Department were also evaluated. Two sorbents containing agents to facilitate sulfation (designated PromiSORB™ A and PromiSORB™ B) were prepared through an EER-Petroleos de Venezuela joint venture. The third sorbent, High Surface Hydrated Lime (HSAHL), was also tested. At a nominal Ca/S molar ratio of 1.75, the following results were achieved:

Sorbent	SO_2 Capture	Utilization
PromiSORB™ A	54%	31%
PromiSORB™ B	66%	38%
HSAHL	60%	34%

The maximum SO_2 capture measured was 81% at a Ca/S ratio of 2.59 using PromiSORB™ B. This material yielded outstanding performance, demonstrating the highest sorbent utilization ever measured in a full-scale SI test. The impact is a significant reduction in the mass flow of sorbent required to achieve a given SO_2 emissions limit. There was also a corresponding reduction in the volume of ash disposal, boiler fouling and sootblower usage frequency.

Boiler Impacts

Although boiler stoichiometries were altered as an inherent requirement of GR and the frequency of sootblower operation was increased due to SI,.no adverse effects on either boiler efficiency or equipment were observed.

GR operation resulted in minimal impact on the heat absorption profile. As a result, steam temperatures also showed minimal variation. However, with SI, the thermal performance was affected by the increase in particulate loading through the upper furnace and convection pass. With increased use of sootblowers, this condition was alleviated, although there was also a slight increase in steam attemperation rate. The boiler efficiency decreased by approximately 1% during GR due to the presence of hydrogen in the natural gas and increase in heat loss due to moisture formed in combustion. Note that a higher flue gas moisture content results from firing natural gas which has a higher hydrogen-to-carbon ratio than coal.

In order to gage the structural impact on the boiler due to operation of the GR-SI system, a series of visual and instrumented inspections were performed both prior to and after testing. The test results were used to determine the existence of degradation and/or equipment failures and assess the wear rates. Of particular interest were the boiler tubes and electrostatic precipitator.

The boiler tubes were examined for tube wear, metallurgical change, and slagging/fouling. All conditions were found to be acceptable. There was no significantly measurable wear of tubes as a result of GR-SI operation. Also, when projecting the life of the tubes, analysis indicated that the scheduled life of the boiler was not compromised either with or without continued use of the GR-SI system.

The precipitator was inspected both before and after testing. The inspections concluded that the precipitator had adequately accommodated the changes in ash loading and resistivity with the presence of sorbent in the ash. During testing, the precipitator was evaluated for particulate matter loading, fly ash resistivity and inlet duct temperature distribution. No adverse conditions were found to exist.

Commercial Applications

The GR-SI project has demonstrated the success of these technologies in reducing NO_x and SO_2 emissions. Utilizing the process design conducted early in the project with the vast amount of data collected during the testing, EER has developed a database of information necessary to apply the technologies to all major firing configurations (tangential, cyclone and wall-fired) on both utility and industrial units. The emissions control and performance can be accurately projected as can the capital and operating costs. GR-SI technology has now been developed to the point that it can be offered by EER on commercial terms.

Economic Considerations

Economic considerations are a key issue affecting technology development. Application of GR-SI requires modifications to existing power plant equipment. As a result, the capital costs and operating costs depend largely on site-specific factors such as:

- Gas availability at the site
- Coal-gas cost differential
- Sulfur dioxide removal requirements
- Value of SO_2 allowances

Based on the results of this project, EER expects that most GR installations will achieve at least 60% NO_x control when firing 15% gas. The capital cost estimate for installing a GR system on units of 100 MW and larger is in the range of $15/kw plus the cost of a gas pipeline (if required). Operating costs are almost entirely related to the differential cost of the gas over the coal as reduced by the value of SO_2 emissions reduction (due to the zero sulfur content of natural gas). Other operating cost factors are related to reductions in ash, mill power and maintenance, and a minor reduction in boiler efficiency, typically 0.0 to 1.0%.

In comparison to wet scrubber technology, SI achieves lower SO_2 control and somewhat higher operating cost, but with capital costs about one-fourth that of wet scrubbers. The capital cost estimate for a SI system is $50/kw. Operating costs are dominated by the cost of the sorbent and sorbent/ash disposal costs. At present, the cost of SO_2 control via SI exceeds the value of SO_2 allowances in most cases.

Summary

The following results can be highlighted from these GR-SI demonstrations:

- GR-SI can be installed and operated successfully on both tangentially-fired and cyclone-fired boilers
- The project goals of 60% NO_x reduction and 50% SO_2 reduction were exceeded at all boiler loads
- The system was operated consistently and reliably
- The system demonstrated no significant thermal impact
- CO can be controlled by exit stoichiometry
- Existing boiler equipment experienced no mechanical degradation or failure

Part A

Public Design Report

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1.0 PROJECT OVERVIEW

1.1 Purpose of the Public Design Report

Part A of this report functions as the "Public Design Report", which is a designated deliverable under the U.S. Department of Energy Agreement No. DE-FC22-87PC79796, Attachment C (Federal Assistance Reporting Checklist). This public design report consolidates for the purpose of public use all design and cost information on the project at the completion of the construction and startup phases of work, prior to the initiation of the demonstration test program. The report contains sufficient information to provide an overview of the project, the salient design features and data, and the role of the demonstration project in the commercialization planning. Part A serves as a reference for the demonstration of the technology as embodied both in the demonstration project and future commercial applications. Since the DOE public design reporting requirement was promulgated after construction and startup, during demonstration testing of the technologies, it has been combined into one Final Overview Report by including Part B, Performance and Economics Report.

1.2 Description of the Project

As a part of the U.S. Department of Energy's Clean Coal Technology Program (Round 1), a project was completed to demonstrate control of boiler emissions that comprise acid rain precursors, specifically oxides of nitrogen (NO_x) and sulfur dioxide (SO_2). The project involved demonstrations of the combined use of Gas Reburning and Sorbent Injection (GR-SI) on coal-fired utility boilers to assess the air emissions reduction potential of these technologies.

Gas Reburning (GR) controls air emissions of NO_x. Natural gas is introduced into the furnace hot flue gas, creating a reducing reburning zone to convert NO_x to diatomic nitrogen (N_2). Overfire air (OFA) is injected into the furnace above the reburning zone to complete the combustion of the reducing (fuel) gases created in the reburning zone. Sorbent Injection (SI) consists of the injection of dry, calcium-based sorbents into furnace hot flue gas to achieve SO_2 capture. At each site where the technologies were to be implemented, performance targets for the demonstrations were air emission reductions of 60 percent for NO_x and 50 percent for SO_2.

Several benefits are derived from combining the GR and SI technologies, including the following:

- Simple method for reducing both NO_x and SO_2 air emissions
- Low capital cost for reducing NO_x and SO_2 air emissions
- Compatibility with coals having high fuel-bound sulfur and nitrogen
- Minimal effects on boiler thermal performance
- Minimal operating complexity

1.2.1 Project History

The development of GR technology had its start in various laboratories in the 1970's. EER, with the support of the EPA and GRI, began extensive bench and pilot-scale testing in 1981 to characterize the fundamental reburning process variables. These tests provided the needed background performance and design data for scale-up to commercial applications.

SI has been under development since the mid -1970's, funding coming from EPA, DOE, EPRI, and several commercial firms. Most of the work focused on identifying the process parameters used to optimize sulfur capture. The work completed under this project included laboratory scale reactivity tests and pilot-scale testing that focused on the system design, boiler performance and operational impacts.

A number of commercial field tests have been completed and additional efforts are in progress. EER has participated both directly and indirectly in much of the development work.

1.2.2 Project Sponsors

The GR-SI demonstrations are being sponsored by:

- U.S. Department of Energy
- Gas Research Institute
- Illinois Department of Commerce and Community Affairs
- Illinois Power Company
- City Water Light & Power of Springfield, Illinois
- Central Illinois Light Company
- Energy and Environmental Research Corporation

1.2.3 Technologies Demonstrated

1.2.3.1 Gas Reburning (GR)

GR involves the injection of natural gas above existing coal fired burners to create a reducing or reburning zone for destruction of NO_x, followed by the injection of OFA above the reburning zone to complete combustion of the reducing (fuel) gases formed in the reburning zone, see Figure 1-1.

This staged combustion technology consists of three zones: 1) a primary zone wherein coal is fired through conventional burners, followed by 2) a reburning zone where additional fuel is added to create a reducing gas condition to convert the NO_x produced in the primary zone to diatomic nitrogen (N_2), followed by 3) a burnout zone to complete the combustion of the reducing gases produced in the reburning zone.

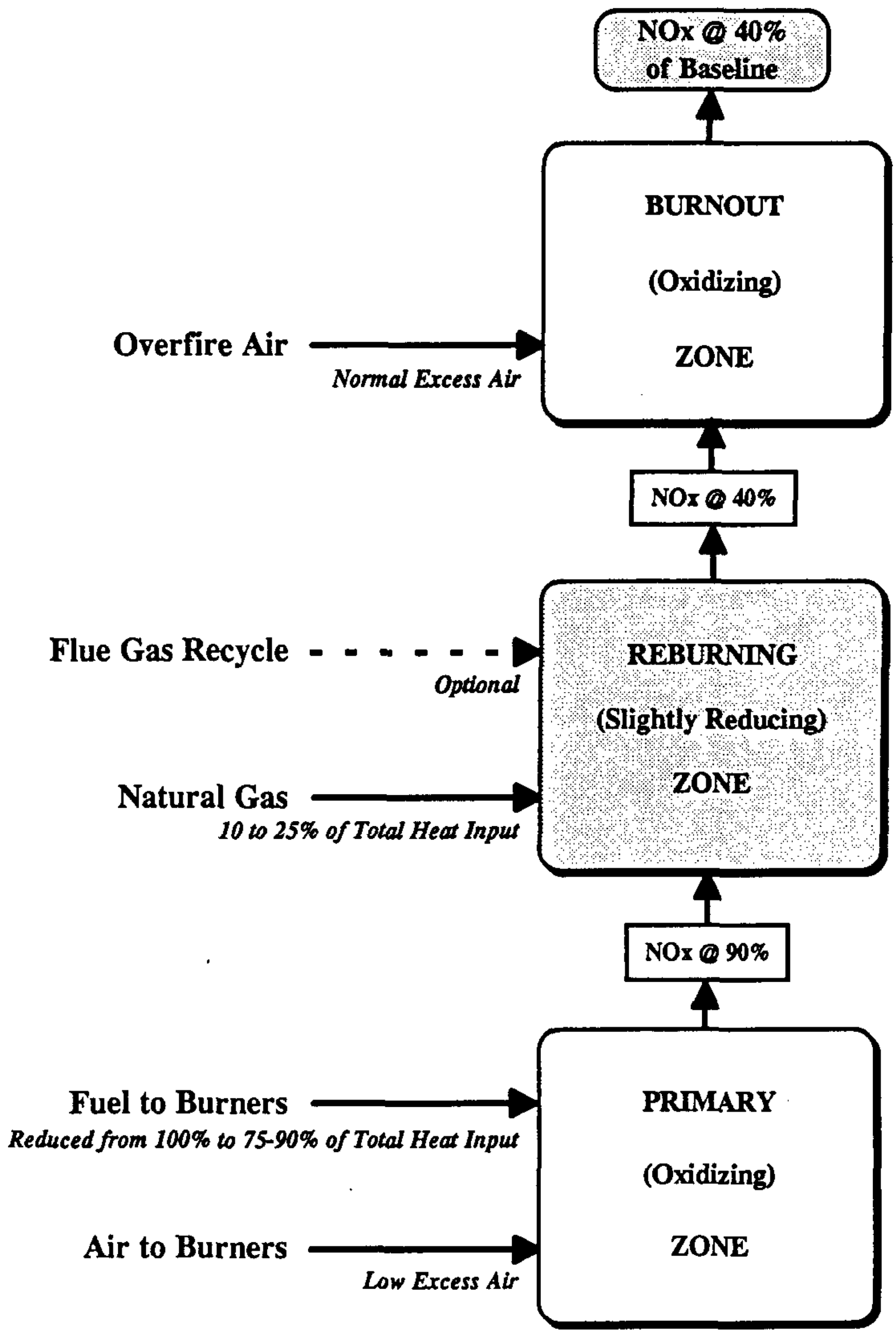


Figure 1-1. Overview of Gas Reburning process

Each zone has a unique stoichiometric air ratio (ratio of air to that theoretically required for complete combustion) as determined by the flow of primary fuel, burner air, natural gas, and OFA. Flue gas recirculation (FGR) through the reburning injectors may also be used to provide increased momentum to the injected natural gas to improve furnace penetration and mixing. Since FGR has a low oxygen (O_2) content, it has a minor impact on the reburning zone fuel requirements and burnout zone air rates. More detailed descriptions of the reburning technology oxidizing and reducing zones are presented as follows:

- Primary (burner) Zone: Fuel is fired at a rate corresponding to 75 to 90 percent of the total heat input, under normal to low excess air. The rate of NO_x created in this zone is reduced due to less fuel being fired (lower fuel bound NO_x production), lower heat release (lower thermal NO_x production) and, if possible, reduced excess air levels to the burners (lower fuel bound and thermal NO_x production).

- Reburning Zone: Reburning fuel (natural gas in this case) injection creates a reducing gas (gasification) region within which methane breaks down to hydrocarbon fragments (CH, CH_2, etc.) that react with NO_x, reducing it to diatomic nitrogen (N_2). The carbon monoxide and hydrogen produced also reduce NO_x, converting it to N_2. The optimum reburning zone stoichiometry is around 0.90 (90% of the stoichiometric air required for complete combustion). This is achieved by injecting natural gas at a rate corresponding to 10 to 25 percent of the total heat input, the range dependent on the fuel fired which sets the primary zone excess air level. The lower the excess air level of the primary zone, the lower will be the reburning fuel requirement.

- Burnout (OFA) Zone: OFA is injected higher up in the furnace, above the reburning zone to complete combustion of the reburning zone fuel gases.

OFA is typically 20 percent of the total air flow, and a minimum excess air of 2.5 to 15 percent, depending on the primary fuel type, is normally maintained. The OFA injection rate is optimized for each specific application to minimize CO emissions and unburned carbon-in-fly ash.

Ambient air is used to cool the gas injection nozzles when the GR system is not in operation. The GR-SI system is controlled by a Westinghouse Distributed Process Family system (WDPF). The WDPF provides integrated modulating control, sequential control and data acquisition for a wide variety of system applications. All start/modulation/stop operations are normally performed in the control room using a keyboard-CRT with custom graphics.

1.2.3.2 Sorbent Injection (SI)

SI technology controls SO_2 emissions through injection of a calcium-based sorbent *such as hydrated lime [$Ca(OH_2)$] into the boiler furnace where it reacts with gaseous* SO_2 to form solid calcium sulfite/sulfate ($CaSO_3$/$CaSO_4$). These solids are then removed from the flue gas through use of an electrostatic precipitator or baghouse.

Sorbent is transported from a storage silo to the boiler and is introduced into the furnace flue gas through injection nozzles. A flow splitter in the sorbent line equally distributes the sorbent to the individual nozzles. To obtain the optimum nozzle velocities required for proper dispersion of the sorbent throughout the furnace flue gases, additional injection air pressure may be required which can be accomplished with a booster air fan. Ambient air is used to cool the nozzles when the sorbent system is not in operation.

1.2.3.3 GR-SI Integration

GR and SI are applied simultaneously to achieve both NO_x and SO_2 control. Although significantly reducing the NO_x emissions, GR also results in an incremental reduction in SO_2 emissions, since natural gas contains no sulfur. This complements the SO_2 reduction of the SI process and reduces the amount of sorbent otherwise required.

1.2.4 Technology Vendor

The Energy and Environmental Research Corporation (EER) has worked on the development of Reburning technology since 1980. It performed extensive bench and pilot scale testing to characterize process parameters and to develop appropriate scale-up methodologies for the design of full-scale systems. The GR demonstrations completed under this project are among the first full-scale applications of GR to coal-fired utility boilers in the United States. Regarding SI technology, prior to the demonstrations under this program, EER demonstrated Furnace Sorbent Injection (FSI) at Richmond Power and Light's Whitewater Valley Unit #2, in Richmond, Indiana (England, 1993). The experience gained in retrofitting this 61 MWe tangentially-fired unit with an SI system was of great value in the design of the GR-SI demonstration projects.

1.2.5 Performance Requirements

The specific performance goals of the these demonstration projects was to achieve NO_x and SO_2 emission reductions of 60 percent and 50 percent, respectively. The focus of the program was to demonstrate the application of combined GR and SI technologies to meet stringent emission regulations when firing medium to high sulfur coals. The overall goal of the project was to meet these emission reduction levels, and do so with acceptable unit operability and minimal operating cost.

1.2.6 Project Block Flow Diagram

To achieve the program objectives, the project was conducted in phases. The following three project phases were applied (refer to Figure 1-2, project block flow diagram) :

- Phase I Design and Permitting
- Phase II Construction and Startup
- Phase III Operation, Data Collection, Reporting, and Disposition

During Phase I, a six volume report was prepared for each of the three potential sites. The volume titles are as follows:

- Volume 1 Summary
- Volume 2 Baseline Test Report
- Volume 3 Process Design Report
- Volume 4 Engineering Design Report and Phase 2 Construction Plan
- Volume 5 Environmental Report
- Volume 6 Phase 3 Test Plan

Phase I, which is completed, culminated with the development of a complete plan for the remainder of the project. During this phase, engineering assessments were made for the application of GR-SI technologies to three host sites:

- Illinois Power's Hennepin Unit #1, a 71 MWe (net) CE tangentially-fired coal unit
- City Water Light & Power's Lakeside Unit #7, a 33 (gross) MWe B&W cyclone-fired coal unit
- Central Illinois Light Company's Edwards Unit #1, a 117 (net) MWe Riley Stoker wall-fired coal unit

As a result of these engineering assessments, Edwards Unit #1 was eliminated for further consideration. This was due to the extensive and costly modifications required

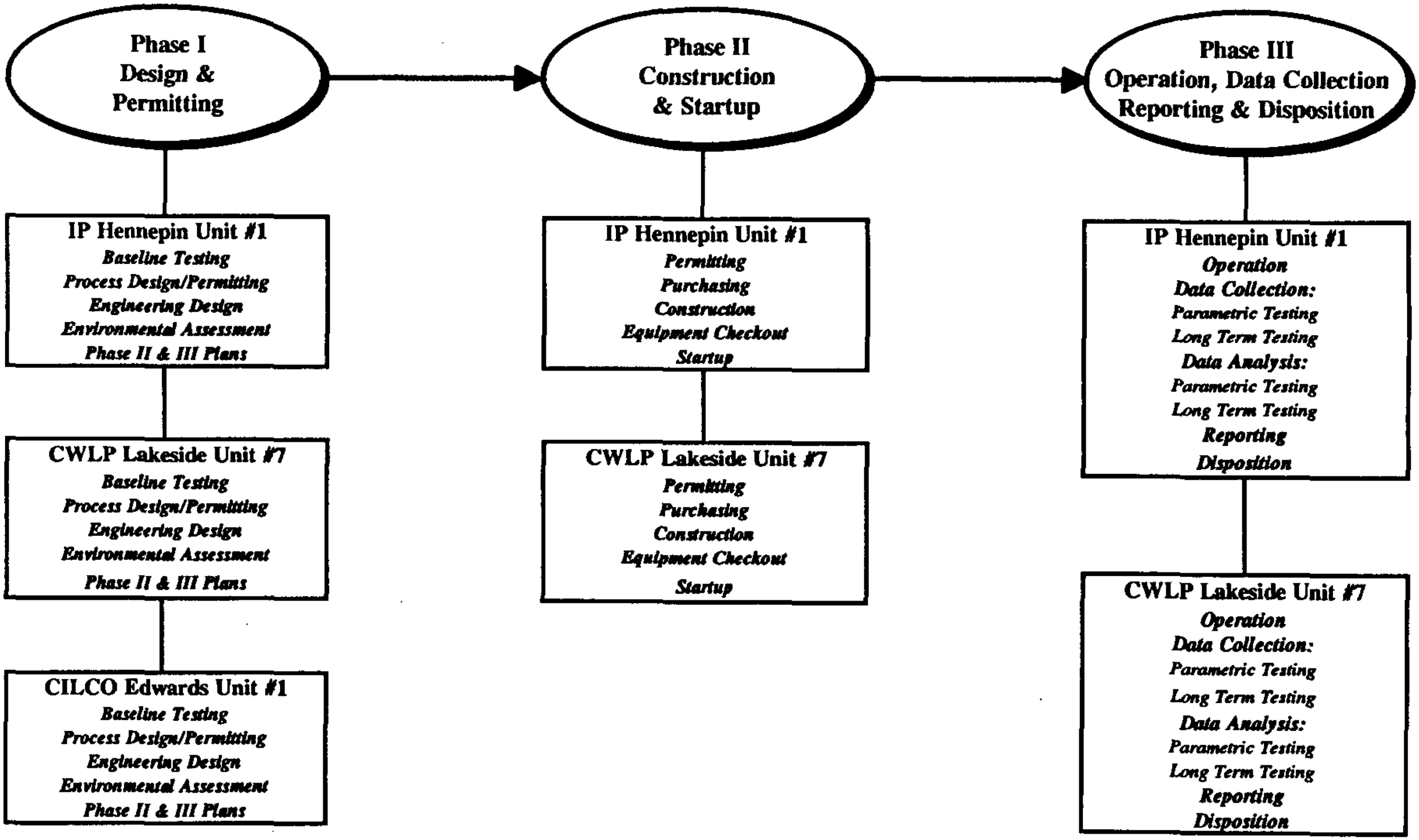


Figure 1-2. GR-SI project block flow diagram

to the existing electrostatic precipitator for the demonstration of the SI technology.

In Phase II, which is also completed, the GR-SI systems were retrofitted to the Hennepin and Lakeside units. Checkout and startup of the equipment was also successfully accomplished.

Phase III of the project involved operational demonstration of the technology. Following startup, a series of pre-planned parametric tests were performed independently on the GR and SI systems. These tests were conducted at different boiler load conditions and involved varying operational control parameters such as boiler zone stoichiometric ratios, natural gas heat input, FGR flow rate, OFA flow rate, sorbent feed rate, etc. Also, an assessment of the effect on boiler emissions and thermal efficiency was completed.

A long term (one year duration) testing program was carried out to judge the effectiveness of the technologies for reducing NO_x and SO_2 emissions over variable load conditions, to assess the impact of the operation on boiler equipment, to gain experience in operating GR-SI in a normal load-following environment, and to develop a database for use in subsequent GR-SI commercial applications.

1.2.7 Project Locations

The first demonstration was performed at Illinois Power's (IP) Hennepin Unit #1, located in Hennepin, Illinois. This unit is a 71 MWe (net) tangentially-fired boiler that fires high-sulfur Illinois coal. The second demonstration was performed at City Water Light & Power's (CWLP) Lakeside Unit #7, located in Springfield, Illinois. This unit is a 33 MWe (gross) cyclone-fired boiler that also fires high-sulfur Illinois coal.

The third demonstration was proposed for Central Illinois Light Company's (CILCO) Edwards Unit #1, located in Bartonville, Illinois. This unit is a 117 MWe (net) wall-fired unit. It was eliminated from consideration after completing the engineering assessment due to the excessive capital cost requirement to upgrade the existing electrostatic precipitator (ESP) so that SI for sulfur dioxide removal could be tested.

Information on the Edwards Unit is not included in this report; however, six reports were issued, as delineated in Section 1.2.6. These reports may be obtained from the U.S. DOE (Cooperative Agreement DE-FC22-87PC79796).

1.2.8 Project Status

The project was awarded in July of 1987. GR-SI systems were designed, installed, started up and tested, both parametric and long term testing being completed. Demonstrations at both the Hennepin and Lakeside sites were successful in meeting project performance goals. The total project cost to complete the GR-SI demonstrations at two electric utility host sites was $37.5 million. The project was completed with the issuance of this report in April 1996.

1.2.9 Summary of Planned Test Programs

For the GR-SI demonstrations at both Hennepin and Lakeside, similar test programs were implemented. The only difference between the two sites was that at Hennepin, a flue gas humidification system was installed and an additional test program implemented to determine the effectiveness of the humidification system in improving the electrostatic precipitator performance.

The objectives of the testing program were to:

- Optimize operation of the GR-SI system
- Demonstrate that performance goals have been achieved
- Quantify costs and operational impacts of the GR-SI system

- Develop a data base for other commercial applications of the GR-SI systems

The planned tests were divided into three broad groups for both parametric and long term testing:

- Tests and inspections during unit outages
- Baseline tests
- GR-SI tests

Tests during outages were intended to document the physical condition of the boiler before and after various periods of GR-SI operation. During each outage of long enough duration to allow access to the boiler, the boiler and ESP were visually inspected by EER and power plant personnel. Boiler tube deposit samples were taken during some of these outages and tube thickness measurements were also completed several times during the test program.

The baseline tests were divided into three types: tests completed during fifty days of normal operation prior to GR-SI testing, standard test points (maximum load) taken before startup of the GR-SI system, and baseline testing at set points each day during optimization and alternate coal/sorbent tests. At the end of a test period, emissions versus load baseline data together with worst case load scenarios were used to calculate 30 day rolling averages to determine what 30 day emission reduction percentages were achieved when using the GR-SI technologies.

The objective of the GR-SI test program was to achieve NO_x reductions of 60% and SO_2 reductions of 50% without adversely affecting boiler operability. The variables that were evaluated during GR-SI testing are shown below in Table 1-1. The unit operability criteria of most interest were:

- Furnace exit gas temperatures
- Tube metal temperatures
- Steam temperatures and attemperation spray
- Combustion efficiency
- Ash deposition (slagging and fouling)
- Particulate emissions and stack opacity
- Fly ash disposal operation

Table 1-1. GR-SI PRIMARY VARIABLES AND THEIR FUNCTIONS

Variable	Major Function	Other Effects
Nat. Gas/Coal Heat Input	NO_x Reduction	SO_2, Particulate Reductions
Sorbent/Coal (Ca/S Ratio)	SO_2 Reduction	Fouling, ESP Performance
Sootblowing Cycle	Fouling Reduction	Tube Erosion
Humidification (Hennepin)	ESP Performance	Fouling, Corrosion
Primary Zone Excess Air	Less Reburning Fuel	Slagging, Increased LOI
FGR Rate	Nat. Gas Dispersion	Furnace Temperatures
Overfire Air (OFA)	Fuel Burnout	Steam Attemperation, Boiler and ESP Efficiencies
Sorbent Transport Air	Sorbent Dispersion	Similar as for OFA

1.2.10 Project Schedule

The overall project schedule is shown in Figure 1-3. After contract award, following finalization of the U.S. Department of Energy - EER Agreement, the project was initiated on July 1, 1987. The project was completed on February 29, 1996.

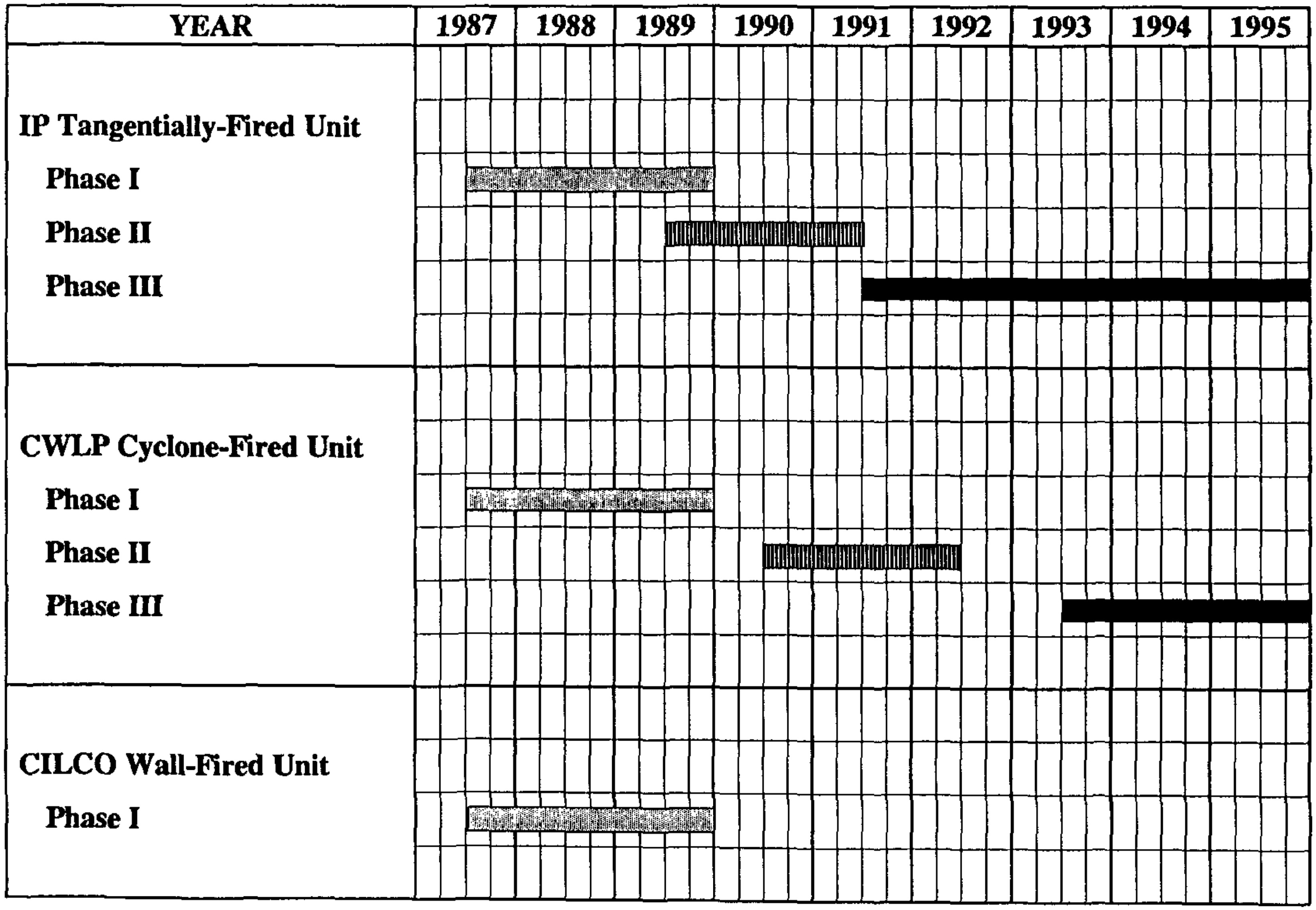


Figure 1-3. GR-SI overall project schedule

1.3 Objectives of the Project

The primary objective of the project was to demonstrate the long term viability of the GR-SI technology on different boiler types and to evaluate the technology for its potential for reducing the major acid rain precursor emissions from these boilers, NO_x and SO_2 by 60%and 50%, respectively. Another objective included providing GR-SI systems that were easy to operate and relatively maintenance free.

The Hennepin GR-SI demonstration project included the installation of a flue gas humidification system. The purpose of this system was to improve the existing ESP performance to maintain low stack opacity levels when sorbent was being injected into the boiler furnace.

With the injection of calcium-based sorbents into a boiler, other acid rain promoters such as hydrogen chloride and hydrogen fluoride will react and also be removed by the sorbent, so another objective was to evaluate the sorbent in regard to removal efficiencies for these minor acid rain precursors.

1.4 Significance of the Project

Coal-fired power plants have been cited as the major source of the acid rain precursors (NO_x and SO_2) and there is considerable pressure within the United States and from Canada to reduce the emissions of these precursors. Current legislation to place further environmental controls on the utility industry is increasing the cost of power and impacting the mining industry in the East and Midwest as utilities switch to low sulfur Western coal to meet their SO_2 emission requirements. To keep down the cost of electricity and to keep the coal mines operating in the East, there is a need for a low-cost pollutant control technology that 1) can be applied without difficulty to existing pulverized coal-fired boilers, 2) can be tuned to the site specific needs of a particular utility, and 3) will have a minimal impact upon the cost of power.

The cost of electricity from pulverized coal-fired boiler/steam turbine plants is influenced as follows:

- Purchased price of coal on a cost/10^6 Btu basis is the prime cost component.

- Coal properties that influence availability, capacity, heat rate, and maintainability also affect the cost of power generation. The properties which translate into the highest maintenance cost are the quantity and composition of mineral matter in the coal. The mineral matter (ash) is erosive thus increasing the wear rate in coal grinding/pulverizing equipment. Also during combustion ash can cause problems due to furnace slagging, steam generator tube fouling and erosion/corrosion. The percentage and composition of the coal ash also dictates the need and size of flue gas particulate control devices.

- Other required pollution control devices used to limit the emissions of nitrogen and sulfur oxides also add to the cost of electricity. Here, the coal properties of importance in determining the cost of the required control equipment are the nitrogen and sulfur content.

The benefits of GR-SI are as follows:

- NO_x emissions are reduced by 60 percent and greater.

- SO_2 emissions are reduced by 50 percent and greater.

- GR-SI provides the utility with flexibility in coal selection to meet acid rain control legislation.

- GR-SI can be retrofitted to pre-NSPS (New Source Performance Standards) tangential, wall or cyclone fired boilers.

- GR may be combined with in-furnace or duct injection SI technologies or with other SO_2 removal technologies such as flue gas scrubbers.

- GR can improve the operability of some pulverized coal-fired boilers.

The GR-SI demonstrations were the first applications to large utility boilers in the United States. GR-SI was demonstrated to be a feasible, low cost and easily retrofitted NO_x and SO_2 control technology. Sorbent requirements to provide a given reduction in SO_2 emissions may be reduced in direct proportion to the percentage of total heat input fired as natural gas. Increased gas usage will reduce the load on the particulate control devices due to less particulate sorbent being required.

GR is applicable to all types of boilers, and since viable commercial NO_x control technologies for cyclone-fired units is limited, GR especially provides a very important NO_x control technology for these units. The NO_x performance results of these successful demonstrations permit comparison of performance and economic factors for agent injection (ammonia or urea) technologies in catalytic or non-catalytic systems and other techniques currently in use to control NO_x emissions from cyclone-fired units.

1.5 DOE's Role in the Project

The U.S. Department of Energy provided both funding and project/technical review. Approximately 50% of the project funds for the design, construction and testing of the GR-SI system were received from DOE. The DOE also provided management review of the GR-SI system designs, construction plans, environmental monitoring plans, and test results. The DOE was responsible for monitoring all aspects of the project and for granting or denying the approvals required by the Agreement between DOE and EER, including direction (or redirection) of the effort and approval of technical reports. Other participants in the project are identified in Section 1.2.2.

1.5.1 Management Plan

The overall management of the program was designed to achieve the program goals in a technically sound, cost efficient and timely manner. EER was the prime participant responsible for conducting this project as directed and funded by the three funding participants: the U.S. Department of Energy (DOE), the Gas Research Institute (GRI) and the State of Illinois

Department of Commerce and Community Affairs (DCCA). Participant and Senior Review Committees were established to ensure that the directions provided to EER by the funding entities were uniform and consistent.

EER was responsible for all aspects of the project performance and coordinated the host site utility and subcontractor work on the project. EER also established an Industry Panel to transfer the project results to industry to encourage commercialization of the GR-SI technologies. EER worked closely with the U.S. DOE Project Manager and the assigned host site managers for the project.

EER continually monitored the cost and schedule status of the project and adjusted the work efforts as required to achieve the project goals. The DOE provided program direction and management review of system designs, construction and environmental monitoring plans, and test results. The DOE was also responsible for granting or denying all change orders required during the project and reviewed and approved all technical reports.

1.5.2 Organization Chart

An overall project organization chart is shown in Figure 1-4. It depicts the management structure of the project and the relationship between EER, the prime participant, the funding participants and the host utilities.

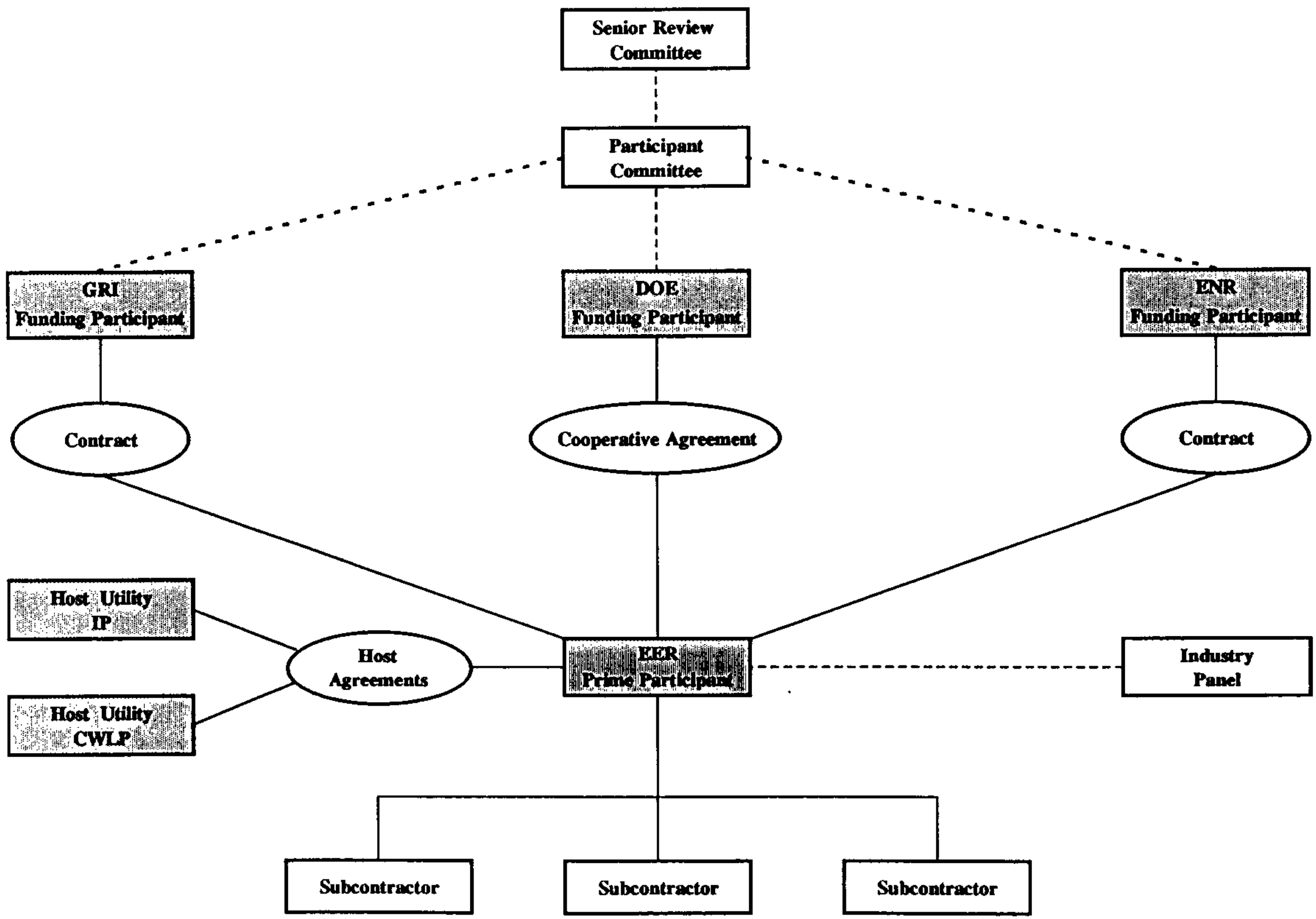


Figure 1-4. Project management structure

2.0 TECHNOLOGY DESCRIPTION

The technologies demonstrated under this project were GR for nitrogen oxide emissions control and SI for sulfur dioxide emissions control. This section presents a brief overview of the GR and SI processes and their history regarding development of the technologies.

Reburning for NO_x control has been under development for the past two decades. Early work in the use of hydrocarbon (HC) fragments to reduce NO_x emissions was conducted by J. Wendt of Shell Oil Development. Other early work in reburning was carried out by the John Zink Company (Reed[1], 1969).

In the early 1980's, commercial reburning technology was first applied on a full scale unit in Japan, where the technology is known as the Mitsubishi Advanced Combustion Technology (MACT), developed by Mitsubishi Heavy Industries Ltd. and Ishikawajima-Harima Heavy Industries Ltd. (Takahashi, et al.[2], 1981).

EER has been working on reburning technology since 1980 and has carried out extensive bench and pilot scale testing to characterize process parameters and develop appropriate scale-up methodologies for full scale applications to U.S. boilers (Chen et al.[3]; 1983, Greene et al.[4], 1985; McCarthy et al.[5], 1985) . The GR demonstrations at Hennepin and Lakeside are among the first full-scale applications of GR to coal-fired utility boilers in the U.S. GR has also been successfully applied to units in Japan, Italy, Ukraine, and Sweden.

Regarding SI technology, prior to the GR-SI demonstrations at Hennepin Station Unit #1 and Lakeside Station Unit #7, EER demonstrated FSI at Richmond Power and Light's Whitewater Valley Station Unit #2, in Richmond, Indiana (England[6], 1993). The experience gained in retrofitting this 61 MWe tangentially-fired unit with an SI system was of great value in the design of succeeding SI systems.

The capture of sulfur dioxide is a direct function of sorbent sulfation which is highly dependent on the injection temperature, the temperature quench rate, the sorbent particle size and porosity characteristics, and the manner in which the sorbent is injected into the boiler. The SO_2 reductions obtained in the Richmond unit tests were correlated to SI process and boiler performance parameters, including the calcium (sorbent) to sulfur (coal) molar ratio, SI configuration (injectors in service), injection velocity, and furnace exit gas temperature. The results of that program added to EER's understanding of the impacts of process parameters and aided in optimizing future designs. The Richmond FSI project was co-sponsored by the Electric Power Research Institute (EPRI) and the U.S. Environmental Protection Agency (EPA).

2.1 Description of the GR-SI Technology

GR-SI is an application of two processes which may be applied separately or together for NO_x and/or SO_2 control (EER[7], 1987). With GR natural gas is injected into the utility boiler furnace above the conventional fuel (coal for these demonstrations) burners (primary zone) to form a slightly sub-stoichiometric reducing region called the reburning zone. Here, hydrocarbon fragments, carbon monoxide and hydrogen reduce NO_x to hydrogen cyanide (HCN), ammonia (NH_3), and the desired N_2. Any HCN or NH_3 intermediates formed in the reburning zone are subsequently converted to N_2 or oxidized back to NO in the burnout zone. In the burnout zone which is above the reburning zone, OFA is injected into the furnace to complete the combustion of the reducing gases formed in the reburning zone. The furnace plane selected to add the OFA is optimized by considering reducing gas and carbon burnout in conjunction with selecting a temperature zone in the furnace that is sufficiently low to prevent re-formation of NO.

In the demonstrations at Hennepin Unit #1 and Lakeside Unit #7, an inert carrier gas was used to enhance the mixing and dispersion of the reburning fuel (natural gas) in the furnace. For these demonstrations, FGR was used as the reburning fuel carrier gas.

The GR-SI process divides the furnace into four zones, as illustrated in Figure 2-1. The zones are as follows:

Primary Zone - Coal fired through conventional burners corresponds typically to 75 to 85% of the total heat input. The nitrogen oxides produced in this zone, which is an excess air combustion zone, is referred to as "primary NO_x". Coal combustion in this zone is operated at as low an excess air level as permitted by constraints such as flame stability, slagging, and fly ash carbon loss. Excess air is minimized to reduce reburning fuel requirements. Since the coal firing rate is reduced to 75 to 85% of the normal firing rate, the reduced burner heat release and lower excess air result in a lower "primary NO_x" level. For the Hennepin tangentially-fired unit the excess air was reduced from approximately 15% at baseline to 10% when using GR. For the Lakeside cyclone-fired unit, the excess air level was not changed from baseline levels due to concerns of creating reducing zones which could create excessive cyclone barrel heat transfer tube wastage.

Reburning Zone - This zone is formed above the burners by the injection of reburning fuel. Reburning fuel is injected at a rate corresponding to 15 to 25% of the total heat input. The design reburning zone stoichiometric ratio is nominally 0.90. The injection location, number of injectors, and amount of carrier gas are optimized to achieve rapid mixing of reburning fuel with the flue gas and to provide for thorough dispersion of the reburning fuel throughout the furnace. The upper furnace volume and gas residence time under reburning zone conditions is a critical design parameter. A residence time of 0.3 to 0.5 seconds is preferred, but residence times as low as 0.25 seconds, such as that for Lakeside Unit #7, still yielded good performance. The flue gas temperature is another parameter which impacts reburning efficiency; higher temperatures have a positive impact by increasing reducing reaction kinetics.

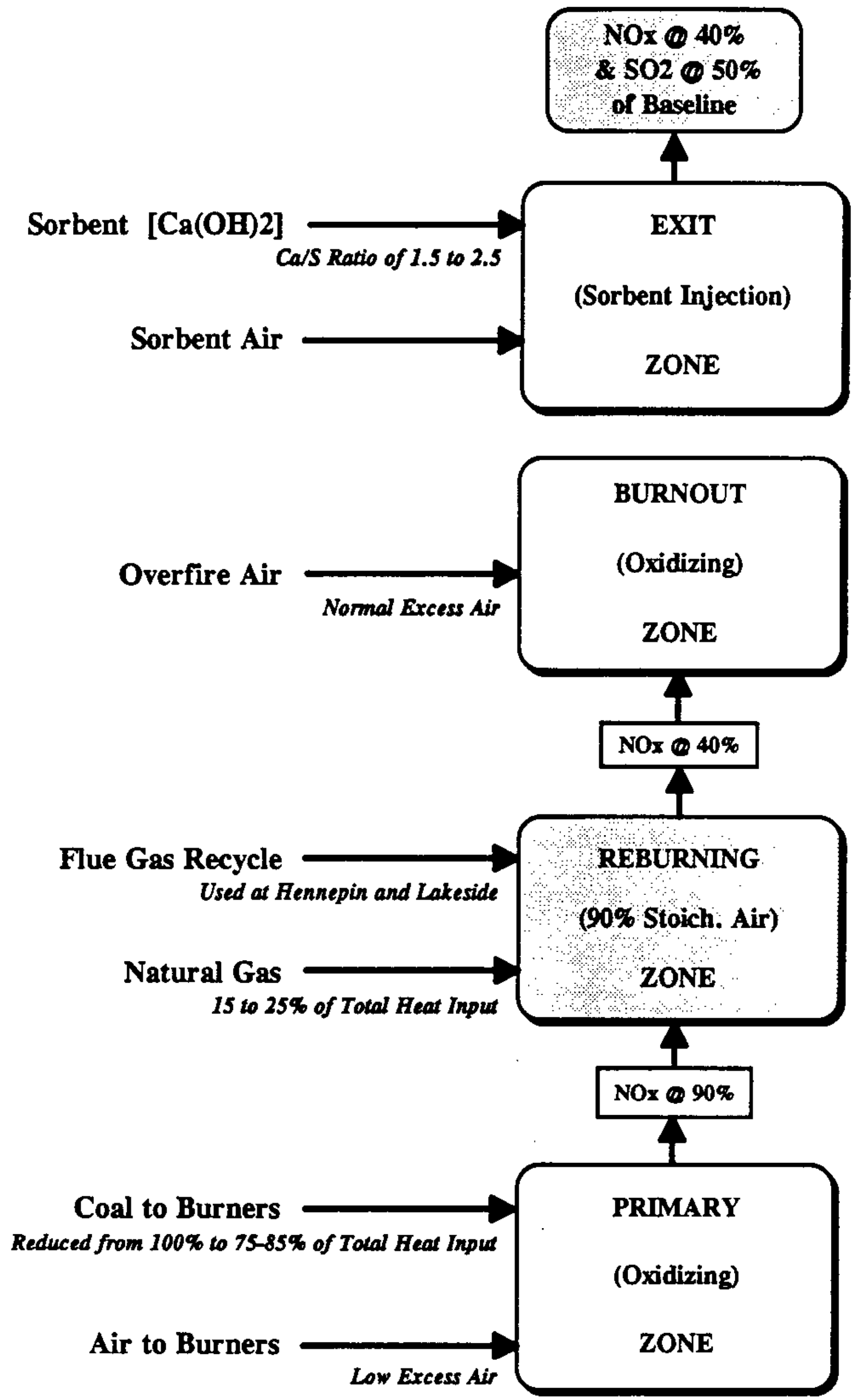


Figure 2-1. GR-SI process used in demonstrations

Burnout Zone - In the final zone, OFA is added to burn out the fuels under normal boiler excess air. OFA is injected at a sufficiently high temperature to burn out CO and carbon in fly ash. To minimize gas temperature quenching, preheated secondary combustion air is used.

The level of NO_x control achieved by GR depends on boiler-specific details, such as the "primary NO_x" level, reburning fuel injection details such as reburning zone residence time and temperature, as well as the type and quantity of reburning fuel.

Exit Zone - When SI is applied with GR an exit zone or SI zone is added. This is the zone where sorbent is injected with air that is used to carry sorbent into the upper furnace. The exit zone stoichiometric ratio is only slightly higher than the burnout zone stoichiometric ratio. With SI, micron-sized sorbent, such as hydrated lime $Ca(OH)_2$, is injected into the furnace to capture SO_2. The sorbent reacts with SO_2 to form calcium sulfate ($CaSO_4$) and calcium sulfite ($CaSO_3$) which are captured by a particulate control device such as an ESP or baghouse.

In the furnace, sorbent first undergoes calcination to form highly reactive calcium oxide, CaO. The furnace reactions to capture SO_2, using a hydrated lime sorbent are as follows:

- Calcination The first step is the thermal decomposition of calcium-based sorbents, such as limestone ($CaCO_3$) or hydrated lime ($Ca(OH)_2$), upon heating. The following two reactions illustrate this process:

$$CaCO_3 + \text{heat} \rightarrow CaO + CO_2$$
$$Ca(OH)_2 + \text{heat} \rightarrow CaO + H_2O$$

- Sulfation The second step is the reaction of the CaO particles with SO_2 and O_2. The surface area and reactivity of the sorbent are functions of the sorbent type and temperature history. Special additives also enhance sorbent reactivity to SO_2. The sorbent sulfation processes are illustrated by the following equations:

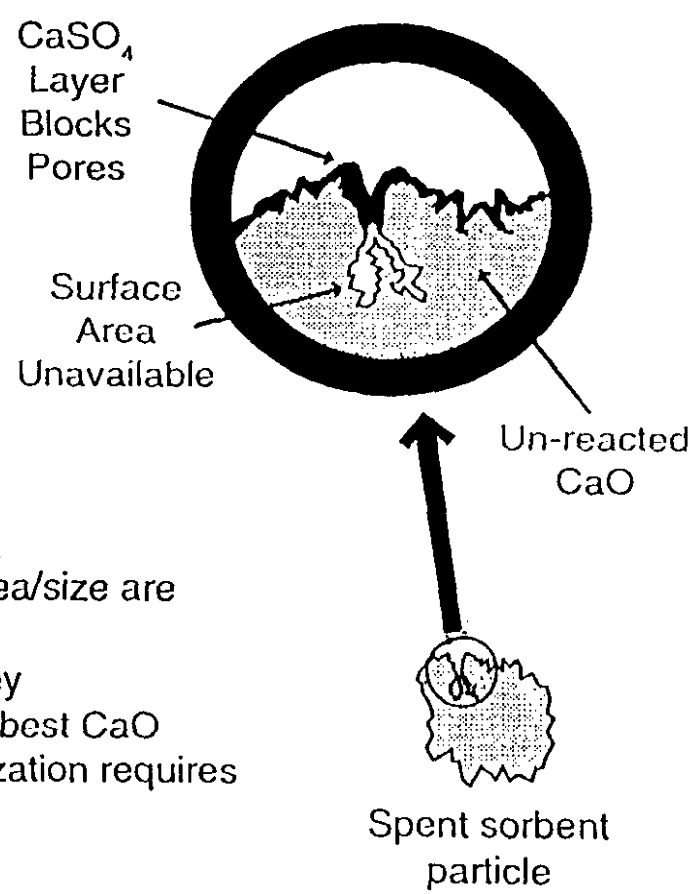
$$CaO + SO_2 + \tfrac{1}{2} O_2 \rightarrow CaSO_4 \text{ (solid) [major]}$$
$$CaO + SO_2 \rightarrow CaSO_3 \text{ (solid) [minor]}$$
$$CaO + SO_3 \rightarrow CaSO_4 \text{ (solid) [minor]}$$

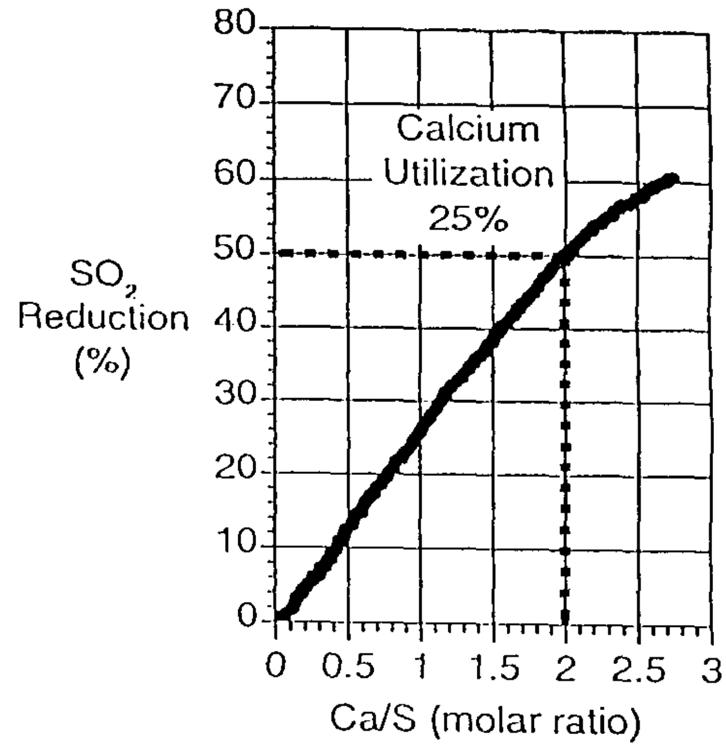
Extensive evaluations of a variety of sorbents were completed both at EER's test facility in Santa Ana, California. Linwood hydrated lime was found to perform well and to be cost effective relative to other commercially available sorbents. Since this sorbent was selected for the tangentially-fired boiler, it was also used at Lakeside for comparison purposes. The composition and properties of Linwood hydrated lime are listed in Table 2-1. This hydrated lime has a high, some 96%, $Ca(OH)_2$ content. The hydrated lime particles are small in size consist and porous which results in a high surface area per unit mass, an optimal feature for reaction with SO_2.

The mechanism for reaction with SO_2, the impact of sorbent properties, and the limitation of SO_2 capture created by sorbent pore blockage, are illustrated in Figure 2-2. The SO_2 control with SI is limited by the rate at which solids may be injected ahead of the superheaters to keep fouling of the convective pass heat transfer surfaces at an acceptable level. Typically, a minimum calcium (sorbent) to sulfur (coal) molar ratio of 2.0 is needed to achieve 50% SO_2 reduction.

Sorbent reactivity is a function of sorbent type, particle size and surface area, temperature history, and the presence of additives. The smaller the sorbent size, the higher the reactive surface area and therefore the greater the reactivity. Sorbent sulfation occurs primarily in a temperature window of 1,600 to 2,200°F (870 to 1200°C). For best sorbent calcium utilization, an adequate gas residence time in this temperature window is required. Therefore, the sorbent must be injected at an optimal

Mechanisms
- SO_2 transport to particle
- SO_2 Transport in pores (limiting)
- Sulfation reactions





Sorbent Properties
- Sorbent surface area/size are second order
- CaO structure is key
- $Ca(OH)_2$ produces best CaO
- Sorbent characterization requires combustion test

Figure 2-2. Key sorbent properties and typical SO_2 control

TABLE 2-1. LINWOOD HYDRATED LIME ANALYSIS

Constituent	Units	Linwood Hydrated Lime
$Ca(OH)_2$	Wt%	95.82
$Mg(OH)_2$	Wt%	0.14
$CaCO_3$	Wt%	1.21
SiO_2	Wt%	1.65
Fe_2O_3	Wt%	0.50
Al_2O_3	Wt%	0.60
SO_3	Wt%	0.08
Total	Wt%	100.00 (normalized)
Surface Area	m^2/g	15.5
Mass Median Diameter	μ	2.88
Density	g/cm^3	2.18
Bulk Density, Loose	lb/ft^3	25
Bulk Density, Settled	lb/ft^3	30

temperature and rapid mixing with furnace gases must occur. The maximum SO_2 reduction is limited by the rate of sorbent injected. Higher rates, although better for SO_2 capture, lead to convective pass fouling and a higher demand on ESP performance.

Standardized methodology was used to design the GR-SI systems; Figure 2-3 illustrates the technical approach used. Field data, including gas temperature and velocity measured at several planes, gaseous emissions, fuel compositions, water/steam cycle data, efficiency/heat rate data and boiler operating data were obtained from field tests during the design phase of the project. The field data were used to calibrate the heat transfer model, define the flow field in the reduced-scale physical flow model, and provide inputs to NO_x and SO_2 reduction kinetics models. The data were also used to evaluate boiler specific GR-SI process requirements to

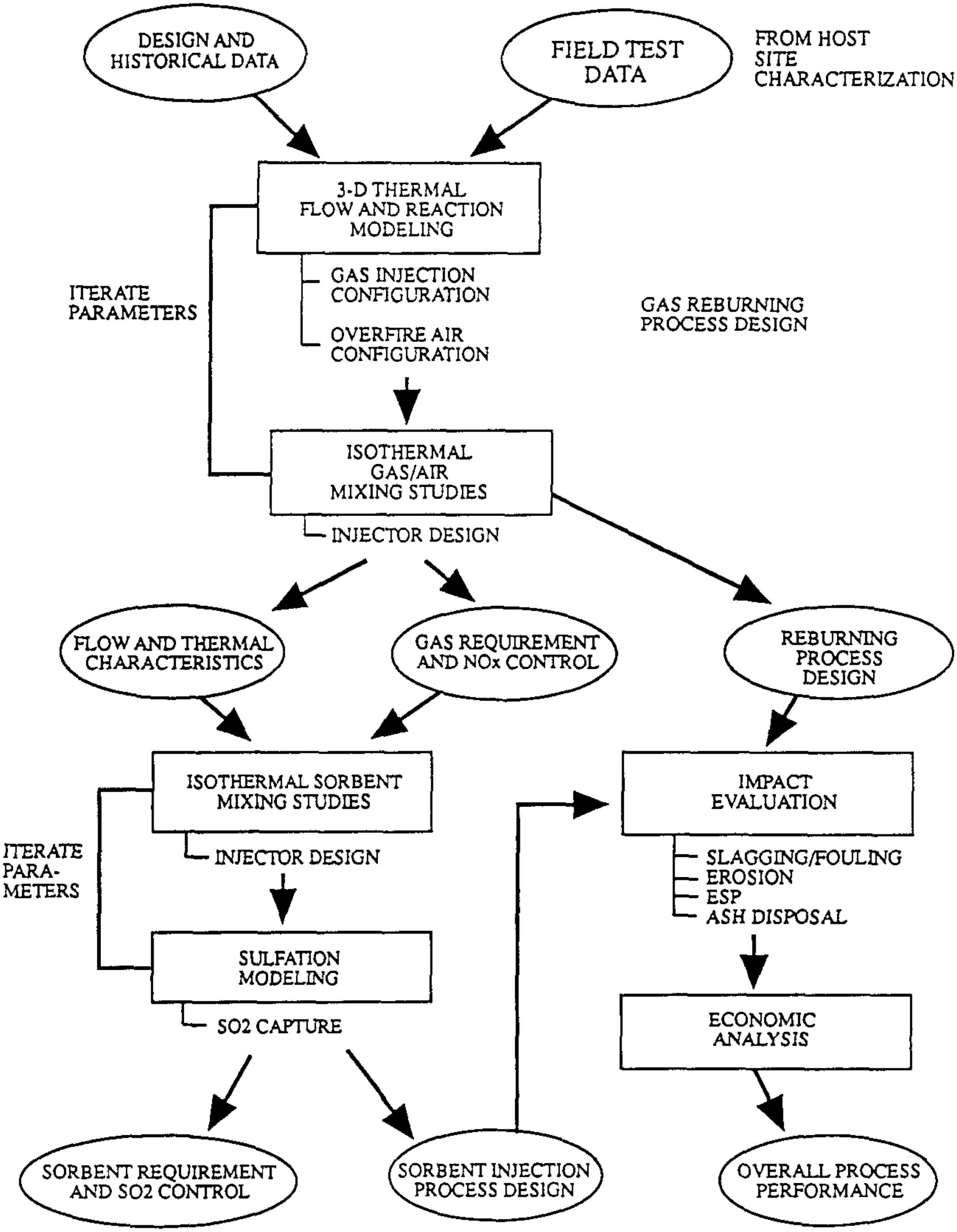


Figure 2-3. Technical methodology used for process design

achieve targeted emissions reductions and to evaluate the performance of candidate reburning fuel, OFA and SI systems. Potential impacts of GR-SI on fireside conditions (slagging /fouling), tubewall wastage, particulate collection by the ESP and solid waste disposal were also assessed.

2.2 Hennepin Unit #1 Demonstration

This host site is located in Hennepin, Illinois and Illinois Power Company owns and operates the Hennepin Station. Unit #1 at the Hennepin site was used for the GR-SI demonstration. This unit was supplied by Combustion Engineering (CE) and began its initial operation in 1953.

2.2.1 Hennepin Host Site Description

The host unit is a 71 MWe (net) CE tangentially coal-fired unit. Figure 2–4 is a schematic showing the major components of the boiler and Table 2–2 contains the design specifications. At its nominal continuous rating, the unit produces steam at a rate of 525,000 lb/hr (66.3 kg/s), at a temperature of 1005°F (541°C) and a pressure of 1450 psig (10,000 kPa). The unit reheats steam at a rate of 462,000 lb/hr (58.3 kg/s) to the same design temperature.

It is tangentially fired with three elevations of coal nozzles located in each of the four corners. The burners have tilting capability to automatically control reheat steam temperature. The convection pass includes a secondary superheater, high temperature reheater, low temperature reheater, primary superheater, economizer and tubular air heater.

Coal is pulverized by three Raymond bowl mills, each having a capacity of 17 tons/hr (4.29 kg/s) to a fineness of 70% passing 200 mesh (74 microns) and 98% passing 50 mesh (297 microns). Coal is pneumatically conveyed using 160°F (71°C) primary

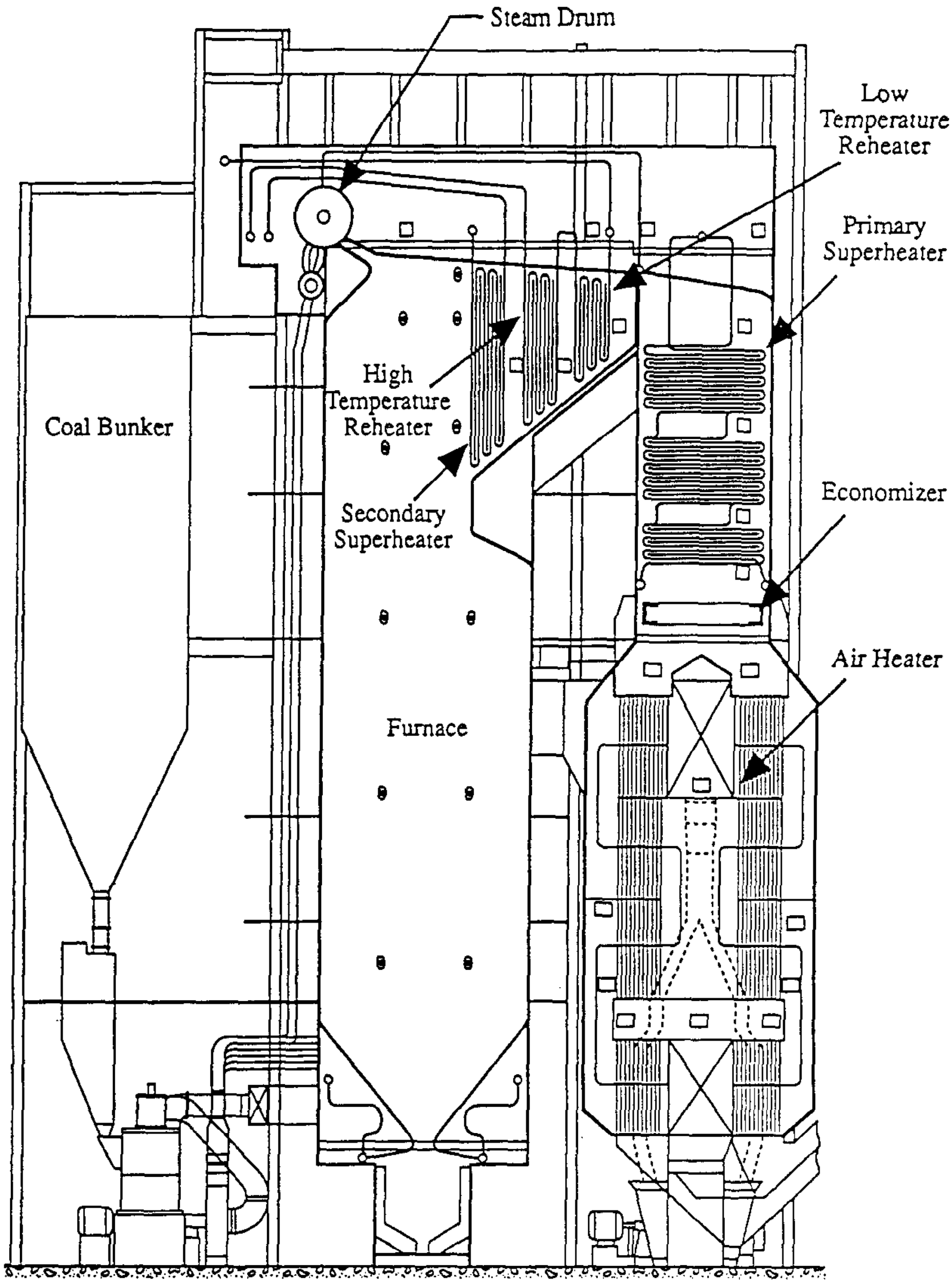


Figure 2-4. Schematic of Hennepin Unit #1

TABLE 2-2. HENNEPIN UNIT #1 BOILER SPECIFICATIONS

Manufacturer	Combustion Engineering
Fuel type	Pulverized Coal, Illinois Bituminous
Boiler Firing Configuration	Tangentially-Fired, Balanced Draft
Number of Pulverizers	3, with 3 Burner Elevations
Superheat Steam Flow Rate	525,000 lb/hr @ Normal Continuous Rating
Superheat Steam Temperature	1,005 °F
Steam Pressure	1,450 psig
Reheat Steam Flow Rate	462,000 lb/hr
Reheat Steam Temperature	1,005 °F
Design Boiler Efficiency	87.0%
Furnace Dimensions	25′ 10" wide x 23′ 11¼" deep
Furnace Volume	49,200 ft^3
Furnace Heat Release	14,100 $Btu/hr/ft^3$
Heating Surface Areas:	
- Furnace	9,465 ft^2
- Superheater	50,000 ft^2
- Reheater	7,830 ft^2
- Economizer	8,950 ft^2
- Air Heater	172,500 ft^2

air from the pulverizers to twelve tilting nozzles, three in each corner of the furnace, where 450°F to 530°F (232°C to 277°C) secondary air is added to complete combustion of the coal in a tangentially swirled combustion zone. The high temperature flue gas then passes through a superheater, reheater, economizer, and a tubular air heater before being ducted to the electrostatic precipitator.

Unit #1 is equipped with a Buell modular electrostatic precipitator. The precipitator was installed in 1974. The specific collection area (SCA) is 223.4 ft^2/1000 acfm (43.97 $m^2/m^3/s$). It has four electric fields and a total effective plate area of 64,800 square feet (6,020 m^2). The particulate collection efficiency is 99.5% with a maximum outlet dust loading of 0.01 grains per acf (0.023 g/m^3). The operating permit for Hennepin Station limits the SO_2 emissions from both Units #1 and #2 to 17,050 lb/hr (2.15 kg/s). To comply with this limit, under all operating conditions, the SO_2 emission potential from the coal being fired must be less than 6.0 lb/10^6 Btu (2,580 mg/MJ).

2.2.2 Hennepin GR-SI Retrofit Requirements

The retrofit of the GR-SI system involved the erection of a sorbent silo, installation of a pneumatic conveying system for transporting the sorbent to the boiler, installation of natural gas piping to gas injectors at the boiler, installation of the OFA system, installation of a FGR system for natural gas injection, and the relocation of the existing induced draft fans. Modifications were also made to the ash handling system, power distribution system, sootblowing system, and control system.

Due to the doubling in particulate loading and the reduction of sulfur trioxide (ESP conditioning agent) in the flue gas created by SI, a flue gas humidification system was installed to enhance the existing ESP performance for the SI demonstration. Modifications to the existing flue gas breeching was required for installation of the humidification system. For more details regarding these retrofit requirements, see

Section 4.2.

2.2.3 Hennepin GR Process Description

The GR process at Hennepin included three integrated systems: 1) natural gas injection, 2) FGR and 3) OFA injection. In the GR process, natural gas is mixed with recirculated flue gas at the gas injection nozzles located above the primary combustion zone. The FGR system provides for added momentum, dispersion and mixing of the natural gas with the furnace flue gases to create the reducing zone required to facilitate reduction of NO to N_2. Above this reducing zone, OFA is added to complete the combustion of the combustibles leaving the reburning zone environment.

A six-inch pipe line supplies natural gas to the reburning control and metering station. From this station natural gas is distributed to the natural gas injector nozzles located at the corners of the furnace. The natural gas valve train, common to all natural gas injection nozzles includes a flow control valve, flow meter and safety shut-off valves. The natural gas injection nozzles are located some eight feet above the highest corner fired pulverized coal burner and are arranged in a similar manner to that for the coal burners.

There are four injection nozzle locations. A nozzle is located on each of the four furnace corners and the injection ports are positioned in a vertical alignment. The gas nozzles, like the coal burners, have the ability to tilt vertically upward and downward (note: the tilt function was later removed). The natural gas injection system was designed to fire 136×10^6 Btu/hr of natural gas, or approximately 20% of the total furnace heat input at full boiler load.

The FGR system delivers flue gas to the natural gas nozzles to improve furnace penetration and mixing of the gas in the furnace. Boiler flue gas is drawn from the breeching between the economizer outlet and the air heater inlet through a multiclone mechanical dust collector into the FGR fan. The multiclone system removes some 80% of the particulate from the flue gas prior to entry into the suction of the FGR fan. The FGR fan boosts the flue gas pressure from -6" W.C. to 28" W.C.. The FGR flow is measured with a venturi flow meter downstream of the multiclone and upstream of the FGR fan. The flue gas from the discharge of the FGR fan is ducted to all four natural gas injection nozzles located on the corners of the furnace. The hot FGR is mixed with the natural gas at the injection nozzles.

2.2.4 Hennepin SI Process Description

The SI system is designed to provide for sorbent unloading and storage, and transport for upper furnace injection. Sorbent is delivered to the site by 25 ton pneumatic tankers and is unloaded to the sorbent silo storage bin, from the silo sorbent is fed into a weigh hopper. A variable speed rotary feeder supplies the sorbent from the weigh hopper to the sorbent screw pump. Here, pneumatic transport air from a positive displacement blower transports the sorbent through high load and low load flow splitters at an adequate rate (proprietary) to provide for continuous flow of sorbent to the upper furnace sorbent injectors. The rotary feeder speed is controlled to meter the flow of sorbent into the system, the rate controlled according to boiler load and Ca/S ratio desired.

2.2.5 Hennepin Humidification Process Description

The purpose of the humidification system was to decrease fly ash resistivity to improve removal performance in the downstream electrostatic precipitator over the range of boiler load from 12 MWe to 71 MWe at full load. The flue gas humidification system was designed to cool flue gases exiting from the air heater at a temperature of approximately 350°F down to a temperature of 175°F, which is approximately 70°F above the dew point temperature of 105°F for the design case flue gas analysis. The system was designed to provide this maximum cooling range of 175° at boiler

MCR, with all humidification equipment sized accordingly. Based upon EER's humidification experience from Richmond Power & Light's Whitewater Station and the performance studies performed by EER and Southern Research with respect to ESP performance, EER did not anticipate having to operate at 175°F, but we designed in the capacity to do so.

When sorbent is added to the flue gas stream particulate loading to the ESP is increased. Further, the sorbent reacts with sulfur trioxide that is formed during coal combustion. Sulfur trioxide is a naturally occurring ESP flue gas conditioner that for high sulfur coals yields fly ash resistivities suitable for good ESP performance. When the sorbent reacts with sulfur trioxide to form $CaSO_4$, fly ash resistivities are increased and ESP performance is reduced. By cooling the flue gas with water spray evaporation, the cooler gas and increased moisture content of the flue gas decreases the resistivity of the fly ash, bringing it into a range (10^8 ohm-cm to 10^{11} ohm-cm) that restores ESP performance.

The flue gas duct on the inlet of the ESP was modified for installation of the humidification system. These modifications were necessary to obtain the residence time required to completely evaporate the water prior to ESP entry. The water for humidification is provided from the plant's service water supply system. A water booster pump was installed to provide the pressure (proprietary) required for good atomization of the water. The water was pumped to six humidification lances, with six dual fluid atomizers per lance. Compressed air was provided to the lances from rotary screw air compressors, and the ratio of air/water was set (proprietary) to provide for good water atomization (evaporation) to cool the flue gas prior to ESP entry.

2.2.6 Hennepin GR-SI Overall Block Flow Diagram

The process units for the GR-SI system are shown in block diagram form in Figure 2-5.

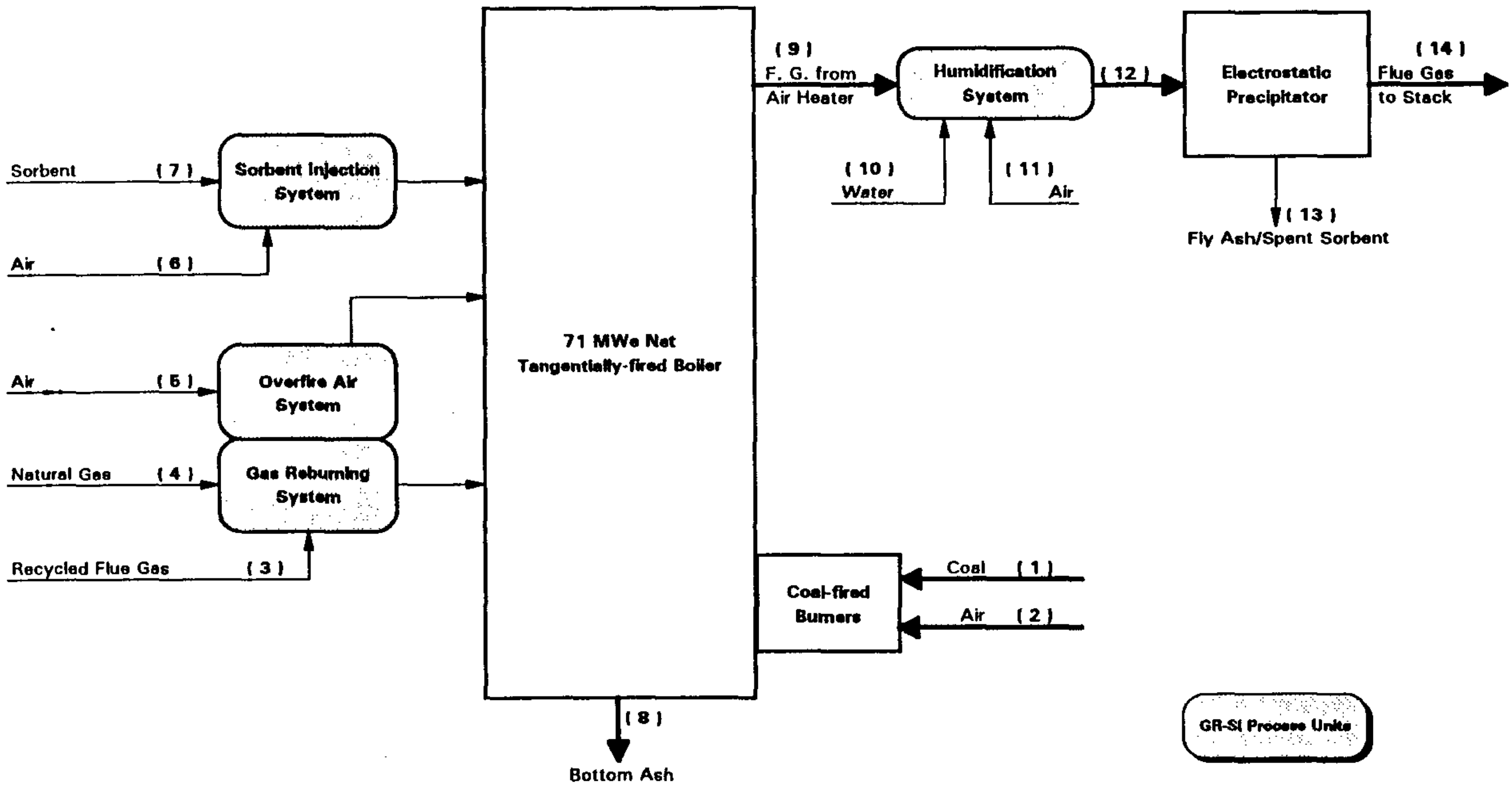


Figure 2-5. Block flow diagram of GR-SI system on Hennepin Unit #1

The natural gas reburning injectors were installed above the existing tangentially-fired coal burners, with OFA being added above the injectors but prior to SI. The reburning control system was integrated into the existing boiler control system. The SI system included a storage silo, weigh hopper and transport system to deliver sorbent into the furnace at a point above the OFA injection point but prior to the furnace exit. The flue gas humidification system was installed in the inlet ductwork to the existing electrostatic precipitator. The original ductwork was modified for installation of thehumidification system. Table 2-3 shows the overall mass and energy balance for Hennepin Unit #1 when applying the GR-SI technology. The mass flow rates for the process streams flowing into and out of the process blocks, as delineated by the stream numbers shown in Figure 2-5, are shown in Table 2-4.

2.3 Lakeside Unit #7 Demonstration

This host site is located in Springfield, Illinois. Unit #7 at the Lakeside Station was used for the GR-SI demonstration. This unit began its initial operation in 1953 and was supplied by Babcock & Wilcox (B&W). The Lakeside Station is owned and operated by the Springfield City Department of Water, Light and Power.

2.3.1 Lakeside Host Site Description

The host unit is a 33 MWe (gross) cyclone coal-fired unit. It is normally operated only five months per year: April, June through August and October. The GR-SI testing was designed to conform to this operating schedule. Figure 2–6 is a schematic showing the major components of the boiler and Table 2–5 contains the design specifications. The unit, supplied by Babcock and Wilcox (B&W), has two seven foot diameter cyclone furnaces on the front wall firing crushed coal. At its Maximum Continuous Rating (MCR) the unit produces 320,000 lb/hr (40.3 kg/s) of steam at a temperature of 910°F (488°C) and pressure of 875 psig (6030 kPa). It has a design efficiency of 88.10%.

TABLE 2-3. HENNEPIN UNIT #1 OVERALL MASS AND ENERGY BALANCE
w/GR-SI @ 71 MWe Net Power Out

Basis: 60°F & H2O as liquid

Input:	**Lb/hr**	**Btu/hr**
Furnace -		
Coal, incl. heat of combustion	57,240	608,571,983
Natural Gas, incl. heat of combustion	6,150	133,581,550
Burner Air	495,147	13,254,496
OFA	152,908	4,093,160
SI Air	19,442	310,853
Sorbent	6,087	27,393
Humidification Unit -		
Atomizing Air	5,000	91,882
Water	12,500	649,875
Total	**754,474**	**760,581,192**

Output:	**Lb/hr**	**Btu/hr**
Furnace -		
Bottom Ash, incl. heat of combustion	1,125	1,034,107
Boiler -		
Energy to Steam Cycle		642,539,430
ESP -		
Fly Ash, incl. carbon heat of	11,521	1,331,311
Stack -		
Flue Gas	741,828	109,864,276
System Heat Loss		5,812,068
Total	**754,474**	**760,581,192**

TABLE 2-4. HENNEPIN UNIT #1 GR-SI MASS BALANCES

Stream No.	1	2	3	4	5	6	7	8
Stream Name	Coal	Burner Air	Recirculated Flue Gas (FGR)	Natural Gas	Overfire Air (OFA)	Sorbent Air	Sorbent $Ca(OH)_2$	Bottom Ash
Rate	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Total	57,240	495,147	23,175	6,150	152,908	19,442	6,087	1,124
Temperature, .°F	60	534	700	60	534	70	70	~3000
Pressure, psia.	14.7	14.9	15.6	16.5	14.9	15.7	14.7	14.7

Stream No.	9	10	11	12	13	14
Stream Name	Flue Gas @ Air Heater Outlet	Humidification Water	Atomizing Air	Flue Gas @Humidification Outlet	Fly ash/Sorbent	Stack Gas
Rate	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Total	735,849	12,500	5,000	753,349	11,521	741,828
Temperature, °F	352	80	80	281	273	273
Pressure, psia.	14.5	95	115	14.5	14.7	14.7

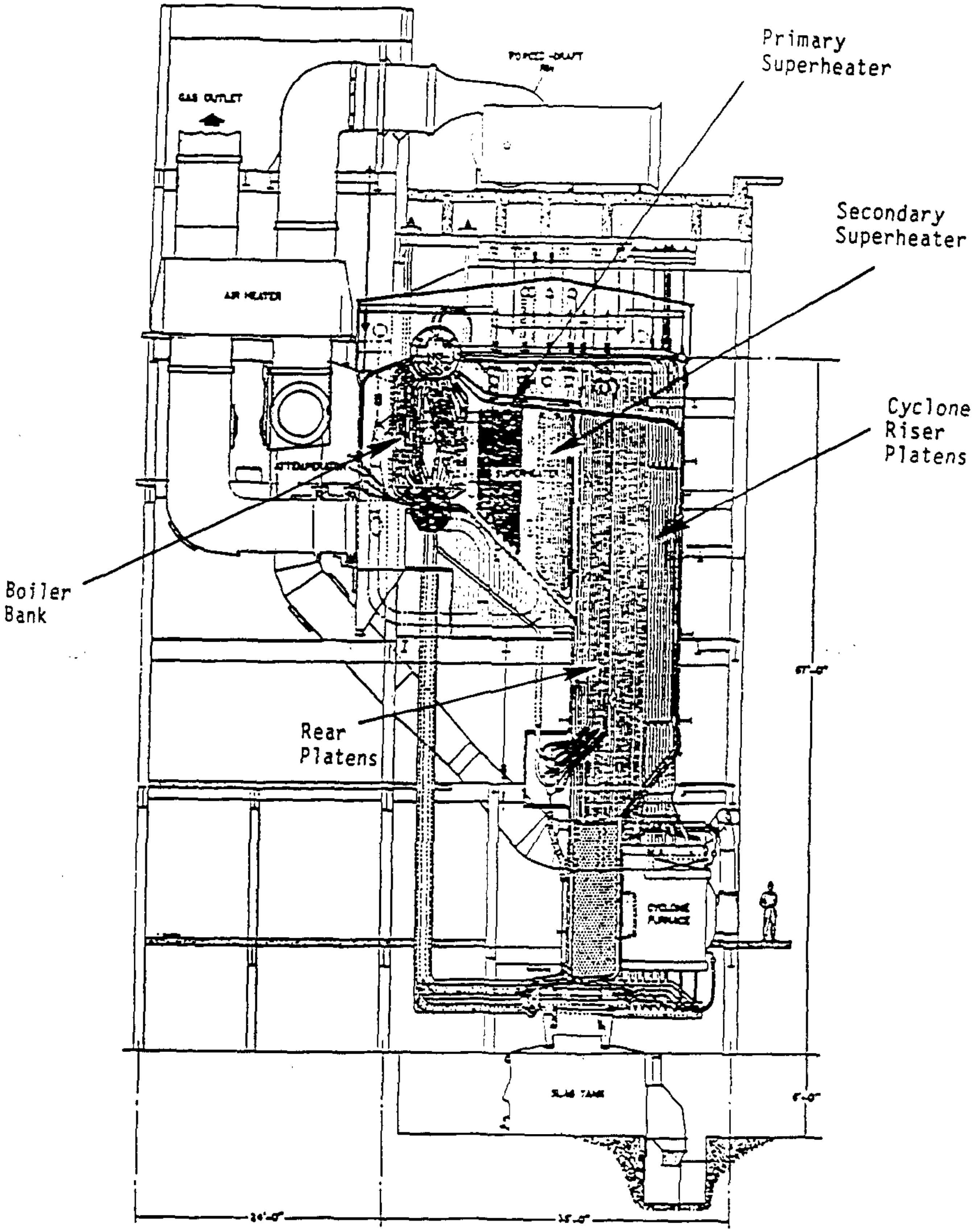


Figure 2-6. Schematic of Lakeside Unit #7

TABLE 2-5. LAKESIDE UNIT #7 BOILER SPECIFICATIONS

Manufacturer	Babcock & Wilcox
Fuel type	Crushed Coal, Illinois Bituminous
Boiler Firing Configuration	Single Wall, Cyclone-Fired
Number and Size of Cyclones	2 - 7 ft. in Diameter
Superheat Steam Temperature	320,000 lb/hr @ Maximum Continuous Rating
Steam Pressure	910°F
Design Boiler Efficiency	88.1%
Furnace Dimensions	18' 0" wide x 4' 6" deep 18' 0" wide x 10' 3" deep
Furnace Heat Release	46,200 Btu/hr/ft^3
Heating Surface of Boiler Components:	
- Boiler	11,854 ft^2
- Water Cooled Wall	5,164 ft^2
- Primary Superheater	9,634 ft^2
- Secondary Superheater	4,013 ft^2

The normal fuel supply is a medium-to-high sulfur Illinois bituminous coal. The cyclone furnaces operate at a very high heat release rate creating molten slag which is captured on the cyclone walls and flows to a slag tap at the bottom of the furnace. Combustion gases pass through a narrow refractory-lined primary furnace, a radiative secondary furnace, then through a convective pass consisting of secondary and primary superheaters, a two drum steam generating bank and a regenerative air heater. The flue gas then passes through an ESP and is discharged to the stack.

Steam temperature control is achieved with a drum attemperator mounted in the upper steam drum. For control of fireside deposits, the unit is equipped with eight wall blowers (IR) in the radiant furnace and seven retractable sootblowers (IK) in the convective pass. The sootblowers use 250 psig (1720 kPa) steam supply.

The ESP is a relatively new unit providing a specific collection area of 500 ft^2 of collecting plate per 1000 actual cubic feet per minute of flue gas (98 m^2/ m^3/s). Flue gases from Units 7 and 8, both of which have a nominal capacity of 33 MWe (gross) flow thru the same ESP. The ESP was designed to receive flue gas from four units, two of which have been decommissioned, therefore it is oversized when receiving flue gas from just two units. Typically only two of the four fields were used prior to initiation of the GR-SI project.

2.3.2 Lakeside GR-SI Retrofit Requirements

Several modifications were required to adapt the GR-SI system to the Lakeside Unit. Natural gas was piped to ten injection nozzles on the boiler rear and side walls. Six of the injectors were designed to mix with FGR to enhance jet penetration and mixing and four were designed to inject natural gas only. The design natural gas input accounts for 23.6% of the total heat input and the FGR corresponds to 3 to 5% of the total boiler exit flow. The FGR system incorporates a high static booster fan and a multiclone dust collector.

OFA is injected through six ports on the rear wall of the furnace. OFA is extracted from two secondary air ducts which have sufficiently high static pressure, therefore the system did not require an OFA booster fan. The flow of OFA through each port is controlled by flow dampers. The SI system was designed to inject sorbent at a rate corresponding to a Ca/S molar ratio of 2.0. The single sorbent/transport air stream is divided into ten equal streams, which are then carried to ten injectors on the front and side walls. Also, injection air is provided to enhance sorbent jet penetration and mixing.

2.3.3 Lakeside GR Process Description

The GR system was designed to convey, meter and inject natural gas through nozzles into the region above the refractory lined primary furnace (reburning zone). The Lakeside Station had no gas firing capability prior to this project, therefore the gas supplier installed a 6" (15 cm) high pressure header to the boiler house with a metering and pressure reducing station. An 8" (20 cm) tie-in line was then installed to carry the natural gas from this station to the reburning fuel flow/pressure regulation and metering system. The natural gas train, common to all injection nozzles, incorporates a pressure reducing valve, flow meter, flow control valve, safety shut-off valve, and vent valves. Natural gas is reduced to a pressure of 15 psig (103 kPa), for injection at a pressure of 2 to 4 psig (14 to 28 kPa). The design gas flow is 1978 scfm (0.9334 m^3/s), with equal flow of 198 scfm (0.0933 m^3/s) through each nozzle.

The nozzles protrude beyond the tubewall into the furnace. This feature helps keep slag from building up and interfering with reburning fuel flow. The nozzles are water cooled to prevent overheating and to further reduce slag deposition. Several types and sizes of injection nozzles were evaluated in this project including ceramic nozzles which had significantly reduced cross-sectional area than originally specified and stainless steel sleeves which did not project into the furnace and had no water cooling. Most testing however was conducted with nozzles nearly identical in dimensions to those originally specified by the design. Nozzle penetrations required bent tube sections. The nozzle wallboxes were designed to permit nozzle cleaning with the unit on line, through use of aspirating air. This was necessary for personnel protection since the unit is a positive pressure design.

Flue gas was extracted from the breeching between the boiler exit and the air heater gas inlet. This location was selected since it is upstream of the air heater, where air leakage increases the O_2 concentration. The normal FGR flow was 19,900 lb/hr (2.51 kg/s). Flue gas was directed through a multiclone dust collector which removes particulate matter to prevent wear of the booster fan. The flue gas was then directed to a high static fan which increased the static pressure from approximately +1" W.C. (0.25 kPa) to +20" W.C. (5.0 kPa). Flue gas was then routed to a venturi for flow measurement, then to the six nozzles where dampers regulated the flow to each injector. The FGR fan was equipped with tight shut-off dampers to prevent gas leakage to the boiler exit when the GR-SI system was not in use.

OFA was obtained from the two secondary air ducts which carry 600°F (316°C) combustion air. Since the unit is a positive draft design, the secondary air is relatively high in pressure, at 45" W.C. (11 kPa), therefore no booster fan was required. OFA was ducted to six ports on the rear wall of the furnace. Butterfly dampers controlled the air flow to each port. The dampers were not tightly shut off, allowing cooling air to flow to the nozzles when the reburning system was not in operation.

2.3.4 Lakeside SI Process Description

The SI system was designed to store, meter, and convey micron-sized sorbent to nozzles on the front and side walls of the upper furnace. The baseline sorbent used throughout this program was Linwood hydrated lime, which was on average 93% $Ca(OH)_2$ and had a bulk density of approximately 30 lb/ft^3 (480 kg/m^3). Sorbent was conveyed with transport/injection air to 10 nozzles on the front and side walls of the upper furnace. Two sizes of injectors, placed at two elevations, were used to completely cover the furnace flow field. The SI system comprised the following major components: sorbent storage silo, weigh hopper, rotary valve feeder, screw pump, air transport blower, conveying line, sorbent splitter, SI air fan, and injection nozzles. The function of each of these is described below.

A sorbent storage silo was erected near the boiler house. It had an internal diameter of 25 ft (7.6 m) and volume of 16,300 ft^3 (462 m^3) . It held three to six days supply for continuous operation, depending on the Ca/S ratio used. Sorbent was transported to the site in tanker trucks. The trucks were unloaded with truck mounted blowers; the transport line was equipped with an industry standard quick connect coupling. The sorbent was transferred to the top/center of the silo using conveying air and discharged into a target box. The conveying air was discharged through a filtered vent. Polyester pleated filter vent cartridges were used with cartridge cleaning from reverse air pulse jets using compressed air. Cleaning air to these filters was provided by a small air compressor. The unit was equipped with a regenerative air dryer. To enhance sorbent discharge through the conical bottom of the silo, six fluidizing air slides were installed. Upon discharge from the silo, sorbent flowed through an automatic slide gate valve, then to a weigh hopper. The weigh hopper had a volume of 200 ft^3 (5.66 m^3). The conical bottom of the weigh hopper was also equipped with fluidizing air slides. The weigh hopper was mounted on four load cells, which are microcell strain gauges, to monitor the quantity of sorbent flow through the rate of weight loss. A rate of weight loss transmitter was used to convey the weight loss signal to the sorbent feed control system.

From the weigh hopper the sorbent flowed through a rotary valve feeder. The operation of this variable speed feeder determined the rate of sorbent flow to the boiler. Directly below the weigh hopper was the sorbent screw pump, which was used to discharge the sorbent into the transport line. It had an 8" (20 cm) screw, which continuously delivered a "plug" of sorbent into the sorbent pickup region of the pneumatic transport system. This solid "plug" prevented leakage of air back into the sorbent delivery system. Above the screw pump were vent filters.

Sorbent transport air was supplied by a positive displacement blower. The conveying air was injected through nozzles into the sorbent pickup region, where it entrained sorbent and carried it into the transport line. The transport line carries the sorbent/transport air to the sorbent splitter, which divides a single stream into ten equal streams for injection at the nozzles. An additional air stream, provided by a high static radial fan, is mixed with the sorbent/transport air stream at the injection nozzles. The portion of the injection nozzles extending into the furnace is stainless steel. The SI system has air cooling fans to provide air to cool the injection nozzles when the system is not in use.

With injection of sorbent into the furnace, it was known that more sootblowing would probably be required. The boiler was equipped with wallblowers in the radiant furnace and retractable sootblowers in the convective pass. These sootblowers utilized pressure reduced saturated steam from the boiler main steam drum. The condition of these blowers was suspect at the initiation of the project, therefore all the sootblowers were replaced. It was expected that the wallblowers would continue to see limited use, but that the sootblowers in the convective pass would be used more frequently (an expected increase from 2 hours per day to 6 hours per day). In practice, SI required virtually continuous operation of the IK convection pass sootblowers.

2.3.5 Lakeside Unit #1 Overall Block Flow Diagram

The process units for the Lakeside GR-SI system are shown in block diagram form in Figure 2-7. The natural gas reburning injectors were installed above the existing cyclones, with OFA being added above the injectors but prior to SI. The reburning control system was integrated into the existing boiler control system. The SI system included a storage silo, weigh hopper and transport system to deliver sorbent into the furnace at a point above the OFA injection point but prior to the furnace exit. Table 2-6 shows the overall mass and energy balance for the power plant when applying the GR-SI technology. The mass flow rates for the process streams flowing into and out of the process blocks, as delineated by the stream numbers shown in Figure 2-7, are shown in Table 2-7.

TABLE 2-6. LAKESIDE UNIT #7 OVERALL MASS AND ENERGY BALANCE
w/GR-SI @ 30 MWe Net Power Out

Basis: 60°F & H2O as liquid

Input:	Lb/hr	Btu/hr
Furnace -		
Coal, incl. heat of combustion	31,050	312,890,850
Natural Gas, incl. heat of combustion	4,450	96,652,147
Burner Air	274,482	7,017,541
OFA	104,110	2,661,733
SI Air	11,358	181,600
Sorbent	4,723	21,254
Total	**430,173**	**419,425,125**

Output:	Lb/hr	Btu/hr
Furnace -		
Bottom Ash, incl. heat of combustion	2,313	1,992,521
Boiler -		
Energy to Steam Cycle		344,828,474
ESP -		
Fly Ash, incl. heat of combustion	6,238	511,493
Stack -		
Flue Gas	421,622	66,659,552
System Heat Loss		5,433,085
Total	**430,173**	**419,425,125**

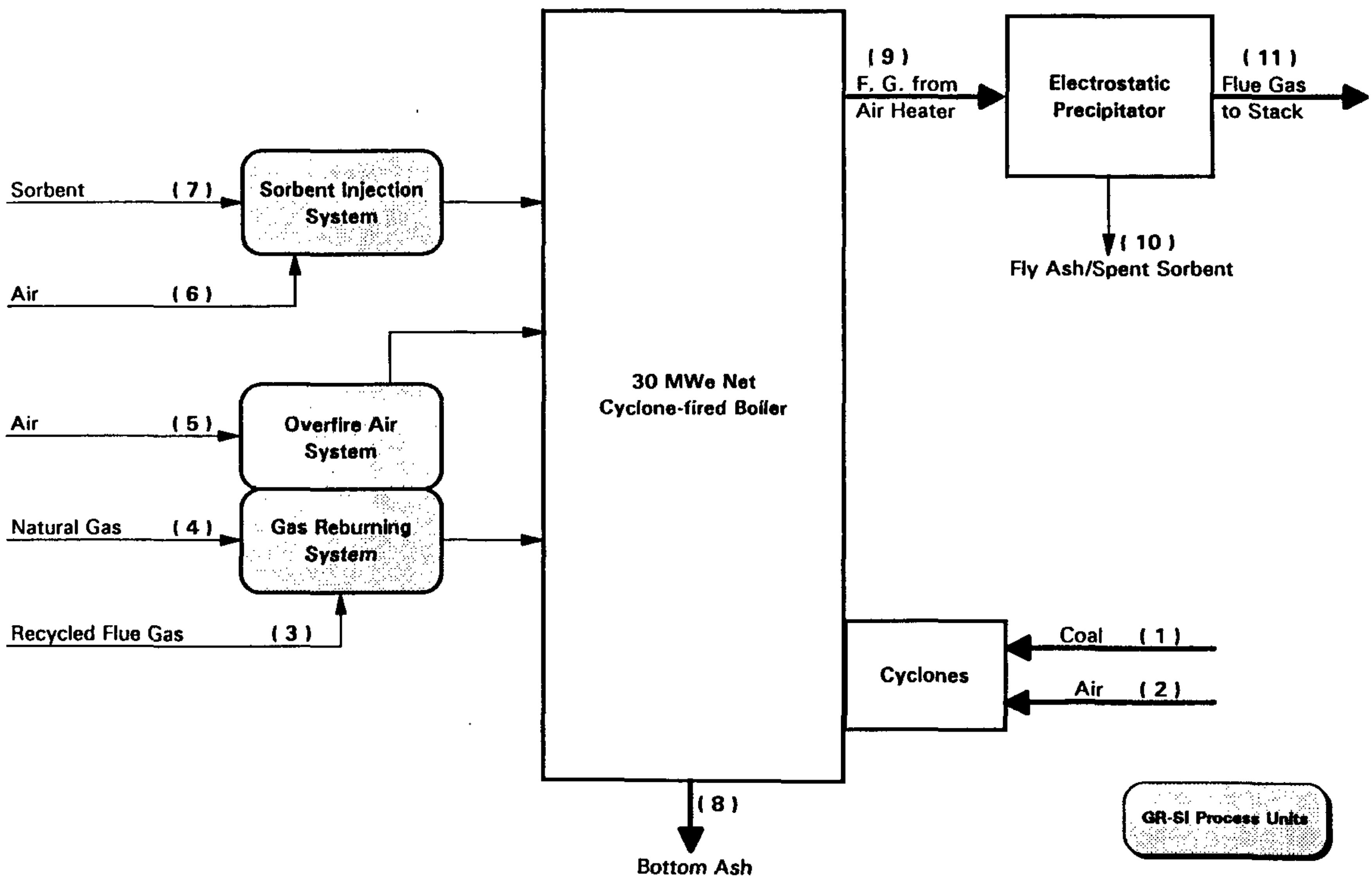


Figure 2-7. Block flow diagram of GR-SI system on Lakeside Unit #7

TABLE 2-7. LAKESIDE UNIT #7 GR-SI MASS BALANCES

Stream No.	1	2	3	4	5
Stream Name	Coal	Burner Air	Recirculated Flue Gas (FGR)	Natural Gas	OFA
Rate	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Total	31,050	274,482	20,000	4,450	104,110
Temperature, °F	60	473	686	60	473
Pressure, psia.	14.7	16.0	15.4	16.7	16.0

Stream No.	6	7	8	9	10	11
Stream Name	Sorbent Air	Sorbent	Bottom Ash	Flue Gas from Air Heater	Fly ash/Sorbent	Stack Gas
Rate	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Total	11,358	4,723	2,313	427,860	6,238	421,622
Temperature, °F	70	70	~2800	343	337	337
Pressure, psia.	15.7	14.7	14.7	14.5	14.7	14.7

2.4 Proprietary Information

The detail and control information on the GR and SI technologies concerning reburning, OFA and SI systems, injection locations and orientations, injection velocities and furnace residence times between zones are considered proprietary.

Reburning NO_x reduction performance depends on a range of different processparameters, which include: initial NO_x level; temperature at the reburning and burnout zones; reburning zone stoichiometric ratio; stoichiometric ratio in the main combustion and burnout zones; residence times in the reburning and OFA zones; and mixing rates of the reburning fuel and OFA. Data gathered during EER's various reburning demonstration programs have been reported in graphical format. Measured NO_x reduction performance has been compared with most of the above variable parameters, and the variable parameters shown have reasonably good correlation as to their effect on NO_x reduction performance.

However, given the rather complex inter-relationship between the various controlling parameters and reburning system performance, EER has elected not to present statistical correlations of the data. We believe that the use of such correlations can be misleading, particularly with respect to extrapolating system performance to other boilers and boundary conditions. To successfully correlate the data requires more complex process models, such as those used by EER during the development of designs for each of the different boiler applications. These process/design models have been validated during the course of the demonstration projects, and have been shown to accurately reflect performance trends as a function of the various process parameters and for boilers of very different design. For business reasons, and because of their importance in developing commercial guarantees, EER prefers not to make public any details of the process models.

3.0 PROCESS DESIGN CRITERIA

Certain design tools were used to arrive at an optimum GR–SI system process design. The final design required optimization of parameters which significantly impact the GR–SI process, including zone stoichiometric (air/fuel) ratios, injection velocities and gas temperature at the injection point. Other important considerations included injection configurations (injector size) and transport/injection flow rates required to accomplish rapid mixing of reburning fuel and sorbent jets. The reburning zone residence time was maximized to effectively form a reburning zone with sub-stoichiometric conditions across the furnace width. The reburning process is also enhanced by high reburning zone temperatures. The calcium hydroxide sorbent analyses used for the SI system tested are shown in Table 3-1. Both Marblehead and

TABLE 3-1. SORBENT ANALYSES

Constituent	*Units*	*Marblehead*	*Linwood*
$Ca(OH)_2$	Wt%	92.00	95.82
$Mg(OH)_2$	Wt%	0.05	0.14
$CaCO_3$	Wt%	1.00	1.21
SiO_2	Wt%	0.56	1.65
Fe_2O_3	Wt%	0.48	0.50
Al_2O_3	Wt%	0.21	0.60
SO_3	Wt%	0.05	0.08
Other	Wt%	5.65	-
Total	Wt%	100.00	100.00 (normalized)
Surface Area	m^2/g	22	15.5
Mass Median Particle Size	μ	5	2.88
Density	gm/cm^3	2.35	2.18
Bulk Density, Loose	lb/ft^3	20-25	25
Bulk Density, Settled	lb/ft^3	30-35	30

Linwood hydrated limes were tested at Hennepin and Linwood was tested at Lakeside.

The OFA injector placement and air velocity were optimized with respect to location and mixing in order to ensure optimum temperature for complete burnout of fuels. Since sorbent sulfation is highly temperature dependent, the process required optimization with respect to location of injectors and injection air requirement. Sorbent sulfation effectively occurs over a temperature range of 1600 to 2200°F (870 to 1200°C), with a required residence time of approximately 1.0 second for sulfation over this temperature range.

3.1 Hennepin Unit 1 GR-SI Process Design

A general arrangement drawing of reburning fuel, OFA and sorbent injectors is shown in Figure 3-1. The proximate and ultimate analysis of the Illinois coal and the composition of the natural gas used in the design phase are shown in Table 3-2.

The design basis for the Hennepin Unit 1 GR-SI system is summarized in Table 3-3. The GR-SI process is applied with natural gas input corresponding to 18% of the total heat input. The primary zone and reburning zone are operated at stoichiometric ratios of 1.1 and 0.9. The formation and reduction of NO_x is optimized through the primary and reburning zone stoichiometric ratios. To achieve the required mixing rate of the reburning fuel with the furnace gases, FGR, corresponding to 3% of the total flue gas, is injected coaxially with the natural gas.

The GR system has four injector assemblies, one in each corner of the boiler. Each assembly consists of four rectangular nozzles separated by an optimal distance to prevent impingement of the reburning jet on the furnace walls. The reburning fuel injectors were designed with tilting capability (which was later removed). The GR process requires adequate penetration of the primary gas stream, without over penetration. The reburning fuel jets must also rapidly mix with (entrain) the primary

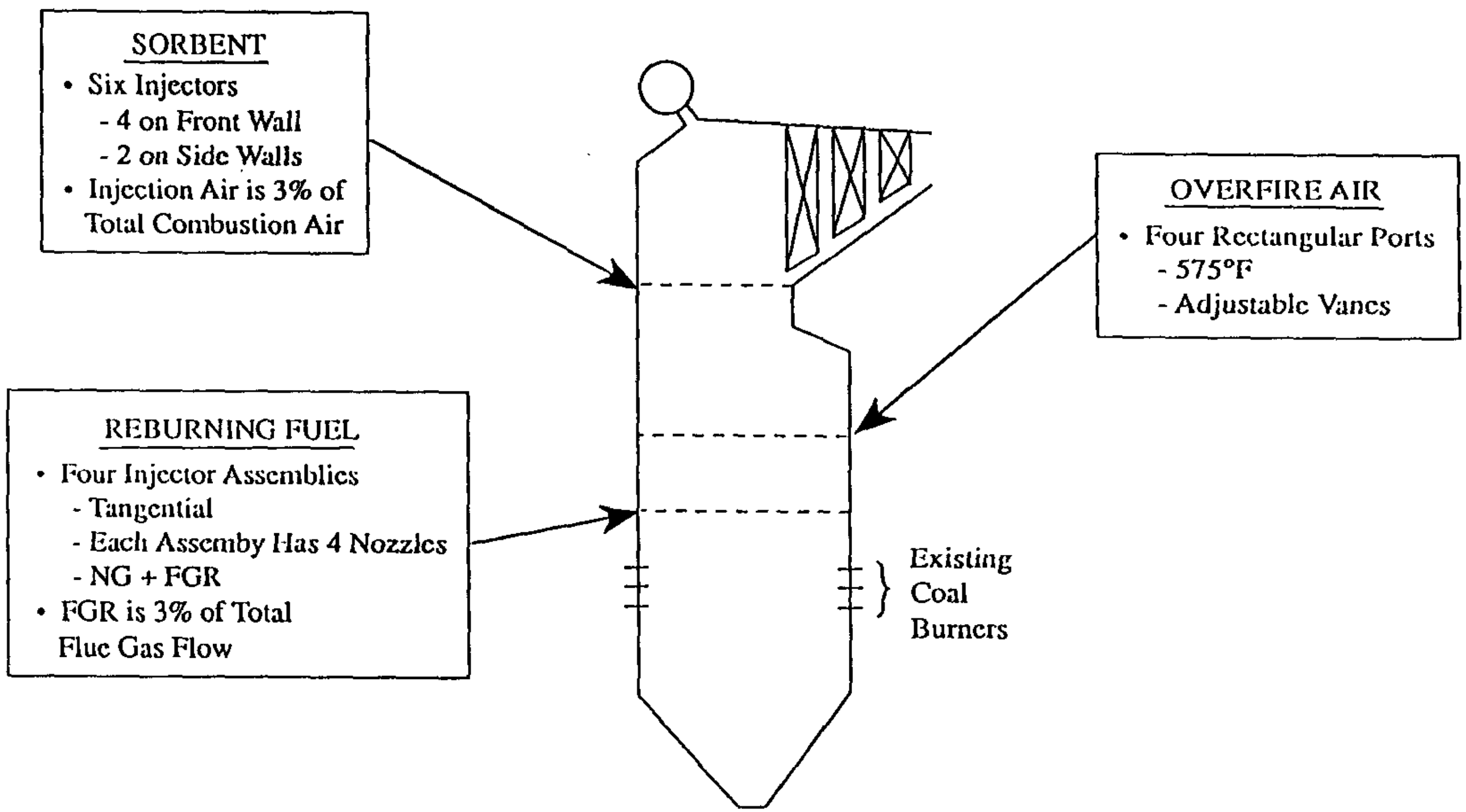


Figure 3-1. General schematic of injector locations for the GR-SI system on Hennepin Unit #1

TABLE 3-2. HENNEPIN COAL AND NATURAL GAS CHARACTERISTICS

	Units	Design
Illinois Coal		
Proximate Analysis:		
Moisture	wt%	15.92
Ash	wt%	9.56
Volatile Matter	wt%	34.57
Fixed Carbon	wt%	39.95
Total	wt%	100.00
Ultimate Analysis:		
Carbon	wt%	59.16
Hydrogen	wt%	3.97
Oxygen	wt%	7.46
Nitrogen	wt%	1.04
Sulfur	wt%	2.82
Chlorine	wt%	0.07
Ash	wt%	9.56
Moisture	wt%	15.92
Total	wt%	100.00
Higher Heating Value	Btu/lb	10,632
Natural Gas		
CH_4	vol%	89.83
C_2H_6	vol%	4.29
C_3H_8	vol%	0.82
CO_2	vol%	0.57
N_2	vol%	4.49
Total	vol%	100.00
Higher Heating Value	Btu/scf	1,014

TABLE 3-3. PROCESS DESIGN BASIS FOR HENNEPIN UNIT 1 GR-SI SYSTEM

Hennepin Boiler		
Unit Capacity	71 MWe (Net)	
Net Heat Rate	10,338 Btu/kWhr	
Nominal GR-SI Conditions		
Stoichiometries		
Primary Burner Zone	1.10	
Reburning Zone Stoichiometry		0.90
Burnout Zone	1.18	
Natural Gas Flow	18% of total heat input	
Recycled Flue Gas	3% of total flue gas	
Overfire Air	24% of total combustion air	
Ca/S Molar Ratio	2.0	
Sorbent Composition		$Ca(OH)_2$
Sorbent Injection Air	3% of total combustion air	
Particulate Matter		
Coal Ash	20% Bottom	
	5% Economizer	
	75% ESP	
Sorbent (reacted and unreacted)		5 %
Economizer		
	95% ESP	

gases, to form the sub-stoichiometric conditions across the furnace cross-section. Therefore, injection location, velocity, and total mass flow were critical design considerations. The injection locations are also essential for adequate residence time in the reburning zone.

OFA is injected to burn out the fuel at a stoichiometric ratio of 1.18. The OFA is injected through four rectangular ports at a velocity less than one-third that of the reburning fuel jets. The OFA is injected at a distance above the coal burners corresponding to a mean gas residence time of 0.5 seconds in the reburning zone (design case). The OFA temperature of 575°F (302°C) is sufficient to complete combustion with only a small gas temperature quench. Isothermal flow modeling showed that a relatively low injection velocity was sufficient to adequately mix with the furnace gas; therefore, an air pressure boosting fan was not required.

Sorbent is injected into the upper furnace through six injectors. The design case sorbent input produces a Ca/S molar ratio of 2.0, which corresponds to a sorbent input of approximately 7,500 lb/hr (950 g/s), at full load of 75 MWe with 18% heat input by gas. The injection location was selected based on the optimum gas temperature and quench rate. Six injectors, four on the furnace front wall and one on each side wall, were used with an injection air requirement of 3% of the total combustion air. The injection velocity was optimized for rapid entrainment of the local furnace flow field.

The 2D Code was used to calculate the mean furnace flue gas temperature as a function of vertical distance for the baseline, GR, and GR-SI operation. The mean flue gas temperature profiles, shown in Figure 3-2, indicate that GR and GR-SI result in only minor impacts on the gas temperature profile. The flue gas temperature is slightly higher than baseline in the burner areas, due to reduced air levels (stoichiometric ratio) in the burner zone under GR and GR-SI operation. The flue gas temperature drops slightly at the reburning fuel injectors due to injection of FGR and then drops

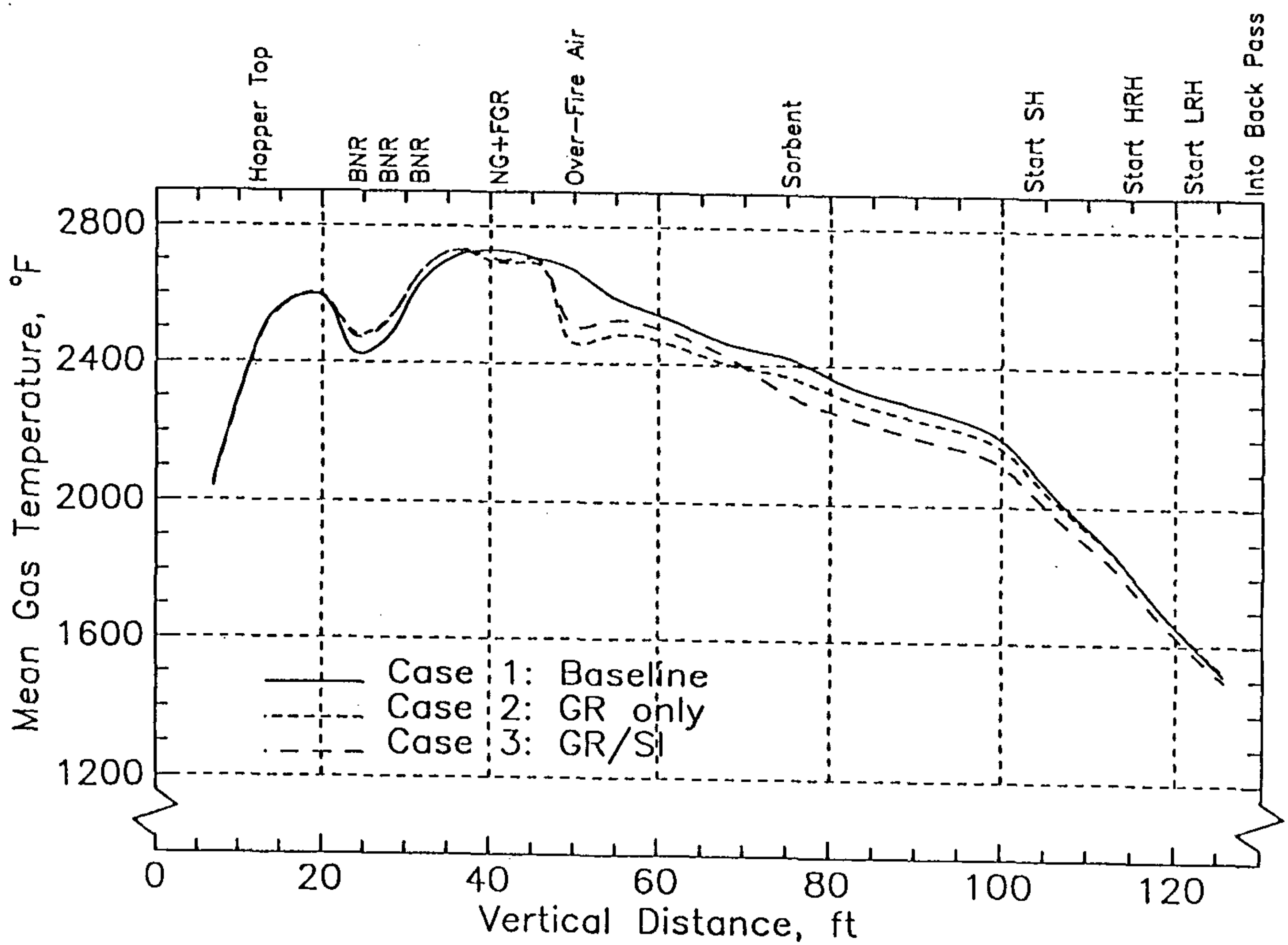


Figure 3-2. Projected mean gas temperature profile for baseline, GR, and GR-SI at full load

significantly at the OFA ports due to injection of burnout air. The flue gas temperature is slightly reduced through the convective passes.

The GR-SI system was designed to reduce emissions of NO_x by 60% from the "as-found" baseline of 0.75 lb/10^6 Btu (323 mg/MJ) to 0.30 lb/10^6 Btu (129 mg/MJ). A 50% reduction in SO_2 emissions from a baseline of 5.3 lb/10^6 Btu (2,280 mg/MJ) to 2.65 lb/10^6 Btu (1,140 mg/MJ) was also projected. These emissions reductions were expected with minor impacts on emissions of other species and on other areas of unit operation. Some reduction in CO_2 emissions was expected, due to fuel switching since the C/H ratio of coal and natural gas are significantly different. A reduction in CO_2 emissions of 7% from firing natural gas at a gas heat input of 18% was expected.

Essentially, no change in CO and hydrocarbon (HC) emissions was expected. The GR-SI system was designed to inject OFA at a sufficient velocity and exit stoichiometric ratio to fully burn out fuel combustible matter. Flue gas humidification was expected to enhance ESP performance during GR-SI, resulting in no increase in particulate matter emissions. A potential increase in PM_{10} (particulate matter with and aerodynamic diameter under 10 microns) was expected since under GR-SI operation approximately 50% of the ESP inlet particulate loading is spent or unreacted sorbent. The sorbent has a mass mean diameter (MMD) of less than 5 microns.

GR-SI operation was expected to have only minor impacts on steam generation/thermal performance. Table 3-4 lists the expected GR-SI impacts on steam production, heat absorption, and gas exit temperature. Minor impacts on the following parameters were expected: main and reheat steam flows and temperatures, boiler exit gas temperature, heat absorption rates in the various areas, and carbon in ash. A minor reduction in main and reheat steam flows (approximately 5,000 lb/hr [0.6 kg/s]) was expected.

TABLE 3-4. HENNEPIN BOILER PERFORMANCE PREDICTIONS
EFFECT OF GAS REBURNING AND SORBENT INJECTION AT 100% LOAD

ITEM	BASELINE	GR-SI
Steam Mass Flows (klb/hr)		
Into Economizer	540.6	533.9
SH Attemperation Spray	14.5	16.5
Exit Superheater	555.1	550.4
Into Reheater	488.5	484.4
RH Attemperation Spray	9.3	8.1
Exit Reheater	497.8	492.5
Steam-Side Temperatures (°F)		
Into Economizer Bank	475	475
Exit Economizer Bank	511	515
Into Primary Superheater	603	603
Exit Primary Superheater	854	868
SH Attemp. Spray Water	475	475
Into Secondary Superheater	815	822
Exit Secondary Superheater	1005	1005
Into RH Attemperator	750	750
RH Attemp. Spray Water	475	475
Into Low Temp. Reheater	717	721
Exit High Temp. Reheater	1005	1005
Heat Transfer to Steam (10^6 Btu/hr)		
Economizer	26.7	28.5
Waterwall	355.5	348.9
Primary Superheater	130.1	133.0
Secondary Superheater	63.8	60.8
Reheaters	76.2	74.4
Gas Side Temperatures (°F)		
Into Back Pass	1424	1414
Exit Primary Superheater	806	817
Exit Economizer	692	701
Exit Air Heater	339	352
Air Temperatures (°F)		
Into Air Heater	115	115
Exit Air Heater	578	591

GR-SI was not expected to affect the unit's ability to reach the design steam temperatures of 1005°F (541°C) that was required for the main and reheat steam. The heat absorption was expected to shift, with lower heat absorption by the furnace and the secondary and reheat superheaters, and higher heat absorption by the primary superheater and economizer. A small increase in the superheater attemperation rate was expected due to firing of the reburning fuel at a higher furnace elevation and heat transfer surface fouling. An increase in the air heater exit gas temperature was also expected, from a baseline of 339°F (171°C) to 352°F (178°C).

A reduction in the thermal efficiency from 85.13 to 84.15% occurred, see Table 3-5. This reduction was expected. It was due primarily to the increased moisture formation associated with the combustion of methane, a much higher hydrogen to carbon ratio fuel than coal. Additional reduction in efficiency was due to the higher boiler exit temperatures.

TABLE 3-5. HENNEPIN THERMAL EFFICIENCY PREDICTIONS USING THE ASME ABBREVIATED HEAT LOSS METHOD

	Baseline	GR-SI
Heat Loss (%)		
Dry Gas	5.95	5.96
Moisture from Fuel	1.95	1.52
Moisture from Combustion	4.11	5.65
Combustible in Refuse	0.81	0.62
Radiation	0.72	0.60
Unmeasured	1.50	1.50
TOTAL LOSSES	14.87	15.85
Thermal Efficiency (%)	85.13	84.15

3.2 Lakeside Unit 7 GR-SI Process Design

The criteria for the GR-SI system design for Lakeside Station Unit 7 are presented in this section. The primary design criteria for the GR-SI system was to reduce emissions of NO_x by 60% and SO_2 by 50% from uncontrolled levels. The design methodology included extensive field testing to characterize the boiler emissions/performance and to evaluate furnace velocity and temperature profiles. Using reaction (sorbent sulfation and NO_x reduction) modeling and isothermal physical flow modeling, the process stream inputs and injection details of the GR and SI systems were finalized. Heat transfer modeling was then conducted to determine the impacts on heat absorptions by each heat exchanger and steam side and gas side temperatures. Potential impacts on various areas of boiler performance including fuel burnout, furnace slagging, waterwall wastage, and ESP performance were also evaluated. The goal in the design of the GR-SI system was to achieve the emissions control goals while minimizing impacts on other areas of unit performance.

The normal coal supply at the Lakeside Station is a medium-to-high sulfur Illinois Bituminous coal, which has seen reduced demand due to provisions of the Clean Air Act Amendments of 1990. The proximate and ultimate analysis of the Illinois coal and the composition of the natural gas used in the design phase are shown in Table 3-6.

The design criteria for the GR-SI system are listed in Table 3-7. It was expected that application of GR-SI would not hinder the operation of the unit at its rated capacity and normal steam conditions (temperature/pressure). A slight reduction in thermal efficiency and correspondingly an increase in net heat rate were expected.

The GR system was designed to achieve 60% NO_x reduction, from 1.0 lb/10^6 Btu (430 mg/MJ) to 0.4 lb/10^6 Btu (170 mg/MJ) at full load, by replacement of 23.6% of the coal heat input with natural gas. The three GR zones have the following design

TABLE 3-6. LAKESIDE COAL AND NATURAL GAS CHARACTERISTICS

	Units	Design
Illinois Coal		
Proximate Analysis:		
Moisture	wt%	19.24
Ash	wt%	9.67
Volatile Matter	wt%	32.56
Fixed Carbon	wt%	38.53
Total	wt%	100.00
Ultimate Analysis:		
Carbon	wt%	55.75
Hydrogen	wt%	3.88
Oxygen	wt%	7.34
Nitrogen	wt%	1.09
Sulfur	wt%	3.03
Ash	wt%	9.67
Moisture	wt%	19.24
Total	wt%	100.00
Higher Heating Value	Btu/lb	10,077
Natural Gas		
CH_4	vol%	89.83
C_2H_6	vol%	4.29
C_3H_8	vol%	0.82
CO_2	vol%	0.57
N_2	vol%	4.49
Total	vol%	100.00
Higher Heating Value	Btu/scf	1,014

TABLE 3-7. PROCESS DESIGN BASIS FOR LAKESIDE UNIT 7 GR-SI SYSTEM

Cyclone Boiler		
Unit Capacity	30 MWe (net)	
Heat Rate	13,500 Btu/kWhr	
Nominal GR-SI Conditions		
Stoichiometric Ratios		
Primary Burner Zone	1.15	
Reburning Zone	0.90	
Burnout Zone	1.15	
Natural Gas Flow	23.6% of total heat input	
Recycled Flue Gas	5% of total flue gas	
Overfire Air	22% of total combustion air	
Ca/S Molar Ratio	2.0	
Sorbent Composition		
$Ca(OH)_2$		
Sorbent Injection Air	5% of total combustion air	
Particulate Matter		
Coal Ash	75% Bottom	
	2% Economizer	
	23% ESP	
Sorbent (reacted and unreacted)		5%
Economizer		
	95% ESP	

stoichiometric ratios: coal (cyclone), SR = 1.15, reburning stoichiometry SR = 0.9, and burnout stoichiometry SR 1.15. The cyclone stoichiometric ratio is limited to minimize NO_x formation in this region and to reduce the quantity of reburning fuel needed to achieve the target NO_x reduction.

The minimum stoichiometric ratio for this zone is based on factors such as fuel burnout and lower furnace slagging. Higher levels of cyclone air help burn out fuel and maintain prevent slag formation in the furnace. Injection of reburning fuel accounting for 23.6% of the total heat input results in a reburning zone stoichiometric ratio of 0.90. Natural gas is injected FGR. corresponding to 5% of the total flue gas, to enhance jet penetration into the furnace and reduce mixing times.

This was deemed necessary in the design since the furnace volume and reburning zone residence time are limited in cyclone-fired units. The reducing conditions in the reburning zone form a variety of hydrocarbon fragments and free radicals which reduced NO_x to HCN, NH_3, and the desirable species, N_2. OFA is injected higher up in the furnace to complete the fuel combustion under a boiler excess air level of 15%. The OFA system is designed to effectively burn out all fuel combustible matter, limiting CO emissions and unburned carbon.

The general arrangement of the GR-SI system is illustrated in Figure 3-3. The original design called for two types of natural gas injectors, one type utilizing FGR, and the other type using natural gas only. Six injectors (four on the rear wall and one on each side wall) would use FGR, while four other rear wall injectors would use natural gas only. These injectors were designed to cover different areas of the furnace flow field. In practice, only the injectors using the flue gas carrier were put into service in the long-term GR-SI demonstration.

The OFA system utilized the high temperature secondary air to minimize gas

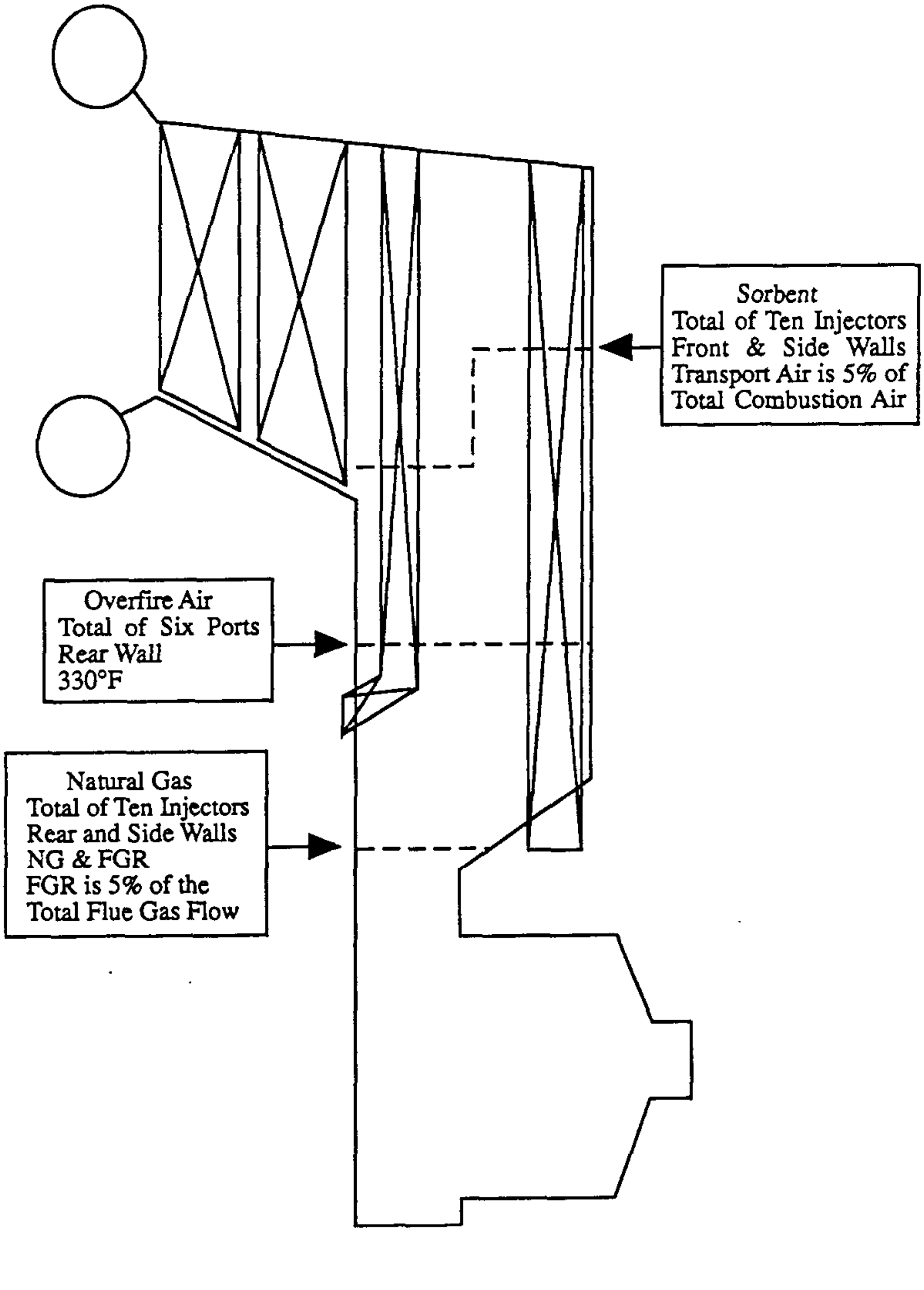


Figure 3-3. General schematic of injector locations for GR-SI system on Lakeside Unit #7

quenching. Six rear wall injectors were used, the secondary air pressure being sufficient without the requirement of a booster fan. Considered in the placement of reburning fuel and OFA injectors were the reburning zone and burnout zone residence times and the expected shift in the furnace temperature to accommodate the SI system.

GR operation was not expected to significantly impact furnace conditions such as slagging and waterwall corrosion. While ash fusion temperatures are lower under reducing conditions, waterwall temperatures were expected to decrease due to the impact of FGR. Lower wall temperatures as well as the reduction in the ash input to the furnace (replacement of coal with natural gas) helps reduce slagging. The potential for reducing conditions to form species with deleterious effects on the waterwall, such as H_2S, was considered. To evaluate the impacts on furnace waterwall wear, extensive tubewall ultrasonic thickness measurements were planned.

The SI system was designed for 50% SO_2 reduction, from the 5.9 lb/10^6 Btu (2540 mg/MJ) baseline. Reduction in SO_2 results from both sorbent SO_2 capture and replacement of coal with the sulfur-free natural gas. Replacement of 23.6% of coal heat with that from natural gas results in an equivalent reduction in SO_2. Therefore, the SO_2 reduction required from sorbent capture was 35%. The GR-SI system design specified a Ca/S molar ratio of 2.0 to achieve this. A safety margin was included in this; design studies indicated that a Ca/S of 1.5 would be sufficient. Sorbent was injected into the upper furnace through multiple ports on the front and side walls. The injection location was selected based on the optimum sulfation temperature range of 1600°F (870°C) to 2200°F (1200°C). An injection temperature of 2330°F (1280°C) and higher results in reduced sorbent reactivity due to loss in active surface area. Rapid mixing of sorbent jets with furnace gas is required to enhance SO_2 capture. Injection air, corresponding to 5% of the combustion air, was used to increase the sorbent jet mass and enhance entrainment and mixing of furnace gas. The injection configuration (number and placement of injectors, total mass flow) was designed to completely cover the furnace flow field.

Results from the EER's previous Furnace Sorbent Injection (FSI) project, at Richmond Power & Light's Whitewater Valley Unit 2, indicated that sorbent deposition in the convective pass must be considered. To enhance heat transfer to the two pendant superheater sections when injecting sorbent, an increase in the operation of sootblowers was anticipated. The unit is equipped with eight wallblowers in the radiant furnace and seven long retractable sootblowers in the convective pass. All of the sootblowers in the unit were replaced since they were originally (before the GR-SI project) in poor condition and their usage was expected to increase. These sootblowers utilize saturated steam from the steam drum, after its pressure has been reduced to 250 psig (1720 kPa). It was expected that the use of the sootblowers would increase from two hours/day under normal operation to six hours/day under GR-SI.

In applying furnace SI, the impact of the increased particulate loading into the ESP was considered. The expected ash split under GR-SI operation was for 75% of the ash to be collected through the slag tap, 2% to be collected in the boiler exit hopper, and 23% to be carried into the ESP. It was expected that 100% of the reacted and spent sorbent would flow to the ESP, since sorbent particles are smaller than fly ash. *The particulate collection device (ESP or baghouse fabric filter) must have sufficient* capacity to handle the added loading and altered electrical characteristics of the fly ash. Using SI, the quantity of particulate matter would be expected to increase by six-fold, while its resistivity would increase by two to three orders of magnitude. The Lakeside unit is equipped with an ESP which was designed for four units (two of which have been decommissioned); therefore, it is oversized for the two units in service. The added solids loading and change in characteristics were not expected to be problematic in maintaining particulate emissions and stack opacity below compliance limits.

GR-SI was expected to have relatively minor impact on the boiler thermal performance. It was expected that the unit would produce steam at its normal rated capacity at the same final temperature as in baseline operation. GR-SI impacts on the unit's thermal performance are summarized in Tables 3-8 and 3-9. The minor reduction in steam output shown in Table 3-8 is due to the reduction in thermal efficiency; these two modeled cases were based on identical fuel heat inputs.

A secondary superheater steam temperature of 890°F (480°C) was expected in both cases, reflecting a 20°F safety margin from the design level of 910°F (490°C). A shift in the heat absorption profile was expected, with lower heat absorption by the furnace and secondary superheater, but higher absorption by the steam drum (including the attemperator). This is due to both GR, in which heat is input higher up in the furnace, and to SI, which results in an increase in particulate deposition on convective heat exchangers. Minor changes in the gas temperature profile were anticipated, with a small rise in air heater exit temperature. A reduction in thermal efficiency of approximately 1% was anticipated under GR-SI, due mostly to an increase in the moisture formation from natural gas combustion. Natural gas has a higher hydrogen/carbon ratio and therefore forms more moisture on combustion. A minor increase in the heat loss due to combustible matter in refuse is also expected.

The expected changes in the gas temperature profile are shown in Figure 3-4. Both GR and GR-SI result in downward shifts in furnace gas temperatures. The reduced coal heat input results

in reduction in lower furnace gas temperature. Addition of natural gas with 5% FGR results in a further drop in gas temperature.

Injection of OFA results in a more significant local drop in temperature. GR-SI was expected to impact the local environment in several ways, necessitating the implementation of an environmental monitoring plan. Monitoring was planned and

TABLE 3-8. LAKESIDE BOILER PERFORMANCE PREDICTIONS
EFFECT OF GAS REBURNING AND SORBENT INJECTION AT 100% LOAD

ITEM	BASELINE	GR–SI
Steam Mass Flows (klb/hr)		
Into Economizer	308.6	304.8
Exit Superheater	308.6	304.6
Steam-Side Temperatures (°F)		
Into Primary Superheater	536	536
Exit Primary Superheater	737	743
Into Secondary Superheater	624	623
Exit Secondary Superheater	890	890
Heat Transfer to Steam (10^6 Btu/hr)		
Drum	79.0	82.3
Waterwall	178.9	173.1
Primary Superheater	51.9	51.8
Secondary Superheater	50.1	49.9
Gas Side Temperatures (°F)		
Into Secondary Superheater	1995	1940
Into Primary Superheater	1589	1558
Into Drum Section	1265	1251
Into Air Heater	761	759
Exit Air Heater	319	322

TABLE 3-9. LAKESIDE THERMAL EFFICIENCY PREDICTIONS
USING THE ASME ABBREVIATED HEAT LOSS METHOD

	Baseline	GR–SI
Heat Loss (%)		
Dry Gas	5.04	5.26
Moisture from Fuel	1.45	1.20
Moisture from Combustion	4.02	5.35
Combustible in Refuse	0.30	0.54
Radiation	0.33	0.33
Unmeasured	1.50	1.50
TOTAL LOSSES	12.64	14.18
Thermal Efficiency (%)	87.36	85.82

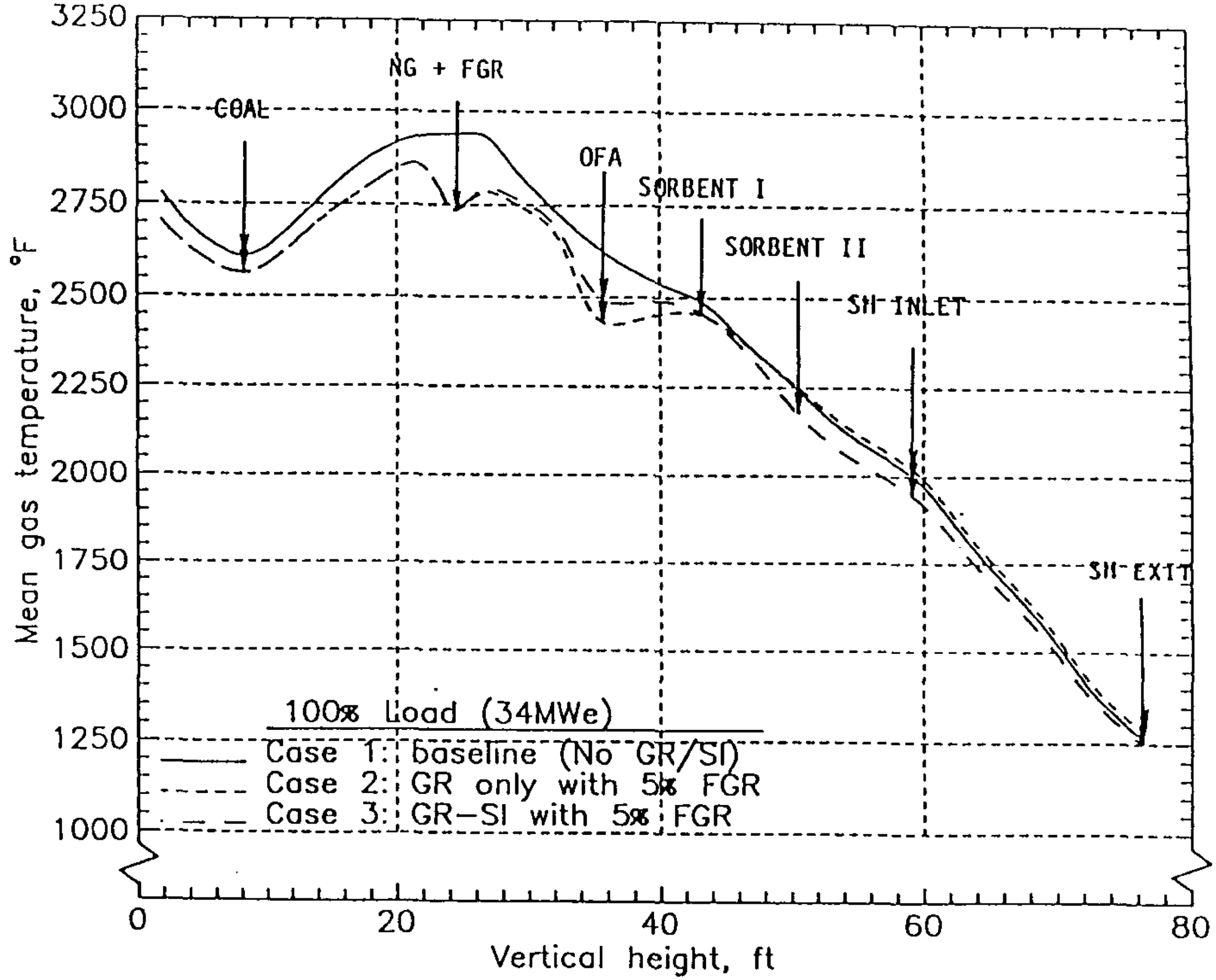


Figure 3-4. Projected mean gas temperature profile for baseline, GR, and GR-SI at full load

executed in two major areas, gaseous emissions and aqueous discharges. Gaseous emissions were monitored by the Continuous Emissions Monitoring System (CEMS) and were supplemented with particulate matter and opacity measurements. Flue gas was sampled continuously from a 16 point grid at the boiler exit and analyzed for NO_x, SO_2, CO, CO_2, CO and hydrocarbons (HC). Aqueous discharges were monitored by plant personnel as required by the Illinois Environmental Protection Agency's (IEPA) National Pollutant Discharge Elimination System (NPDES) permit.
The expected impacts of GR-SI on air emissions are positive, including significant reductions in NO_x and SO_2. Only modest changes in the emissions of other species were expected. A reduction in CO_2 emissions of 10% was expected from replacing 23.6% of coal with natural gas. Coal combustion produces CO_2 at a rate of 204 lb/10^6 Btu (87.7 g/MJ), while natural gas combustion produced CO_2 at a rate of 116 lb/10^6 Btu (49.9 g/MJ).

Low emissions of CO and hydrocarbons HC were expected from judicious design of the OFA system. CO emissions were expected to be in an acceptable range for coal-fired utility boilers (under 200 ppm). Because of the large capacity of the ESP (specific collection area of 500 ft^2/1000 ACFM flue gas) emissions of particulate matter and opacity at the ESP outlet were expected to fall within regulatory limits. Applicable limits are 0.1 lb/10^6 Btu (43 mg/MJ) of particulate matter and an opacity of 30%.

Detailed evaluation of the baseline ESP performance data and computer modeling of ESP performance indicated no ESP performance enhancement would be required. Stack sampling of particulate matter, under GR-SI operation, was conducted at the conclusion of the test program, while opacity measurements were made continuously.

The major GR-SI waste product is a high-calcium fly ash, which was thoroughly characterized in Phase I of the project. Leaching characteristics were tested and the negative results indicate that it is a non-hazardous waste. The GR-SI system incorporated a fly ash silo adjacent to the sorbent storage silo. The fly ash has been observed to have pozzolanic characteristics; i.e., it forms into a cementitious material upon addition of water. The buildup of this material may render an ash sluicing system inoperable. Therefore, fly ash was collected in hoppers under the ESP, then conveyed pneumatically to the storage silo. It was loaded onto trucks with a dustless unloader which added a small quantity of water to help prevent fugitive dust emissions. The fly ash was then disposed of at an off-site landfill.

No change in the makeup and characteristics of the aqueous discharges were expected. Only the bottom ash was sluiced to the ash pond and its makeup was not expected to change due to GR-SI. Sorbent was injected into the upper furnace, too high in the furnace to fall to the boiler bottom. In addition, its small size ensures that it is entrained in the flue gas. Therefore, the ash pond discharge into Lake Springfield was not expected to change under GR-SI operation. The other aqueous stream which could have been affected is the coal pile runoff, because sorbent is unloaded in this area. The NPDES permit required regular monitoring of these steams for pH, Total Suspended Solids (TSS), oil/grease, and other constituents.

4.0 DETAILED PROCESS DESIGN

This section presents details of the process designs for the GR-SI applications to Hennepin Unit #1 and Lakeside Unit #7.

4.1 Hennepin Unit #1 Detailed Process Design

The Illinois Power Hennepin Station is located in Hennepin, Illinois, seventy miles north of Peoria, along the Illinois River. Figure 4-1 is a plot plan of the plant. The GR-SI system was applied to Hennepin Unit #1, a 71 MWe tangentially-fired boiler burning Illinois high sulfur coal.

The retrofit of the GR-SI systems involved installation of gas piping and injectors, an FGR system, an OFA system, additional sootblowers, a sorbent storage silo, installation of a pneumatic conveying system for transporting sorbent to the boiler furnace injectors, modifications to the existing flue gas breeching at the inlet to the ESP to accommodate the installation of a humidification system, and the relocation of existing induced draft fans. Figure 4-2 is an equipment isometric drawing of the GR-SI system installed on Hennepin Unit #1. An overall process flow diagram is provided in Figure 4-3.

4.1.1 Mass and Energy Balances

Mass balances that correspond to the stream numbers shown in Figure 4-3 are shown in Table 4-1. Mass and energy balances around each of the subsystems, the furnace, boiler/economizer, air heater, humidification system, and electrostatic precipitator, are shown in Tables 4-2A through 4-2E. The mass and energy balances are based on a full boiler load condition to produce 71 MWe net electrical power. The furnace mass and energy balance reflects the effect of the GR-SI technology on the system.

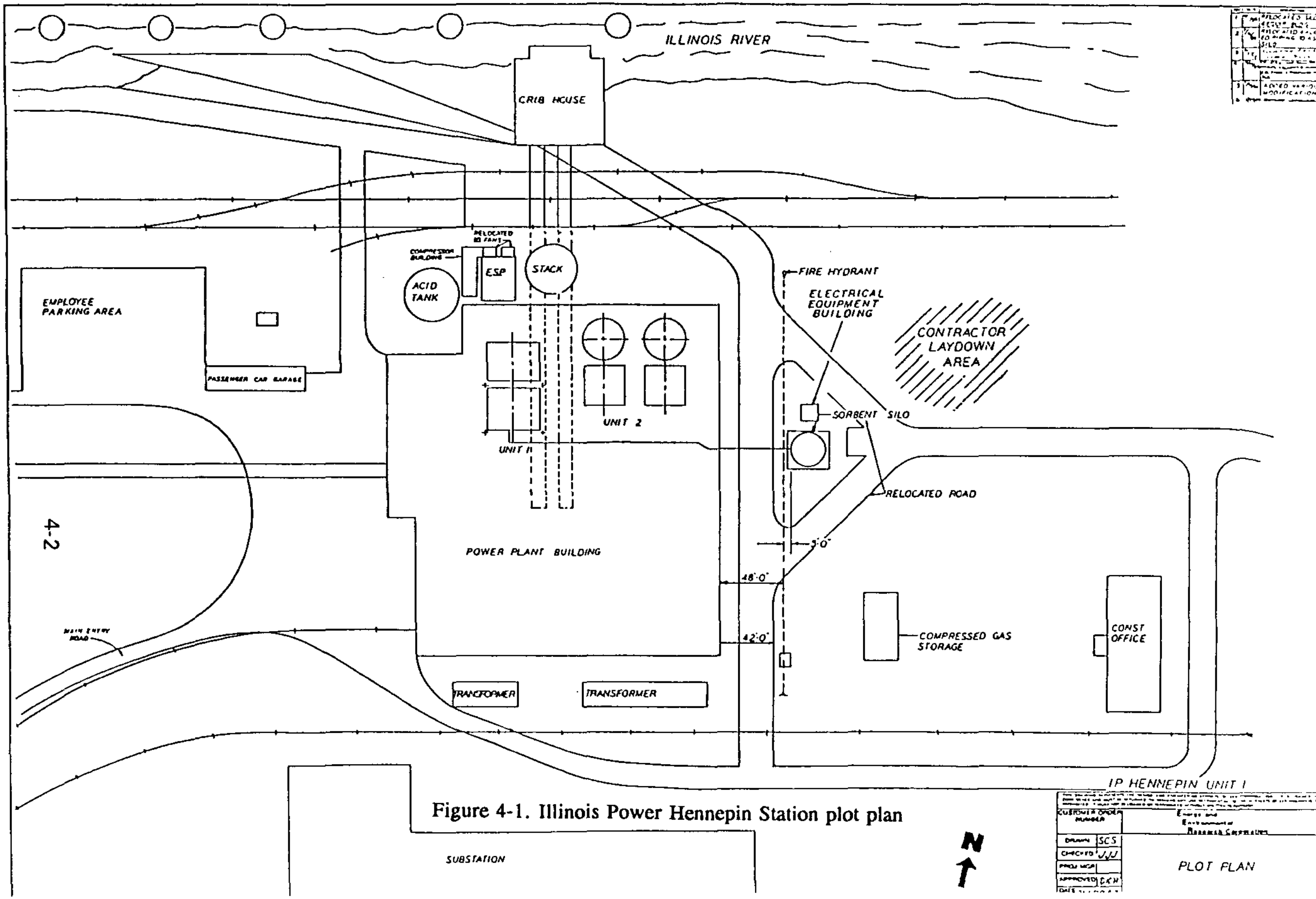


Figure 4-1. Illinois Power Hennepin Station plot plan

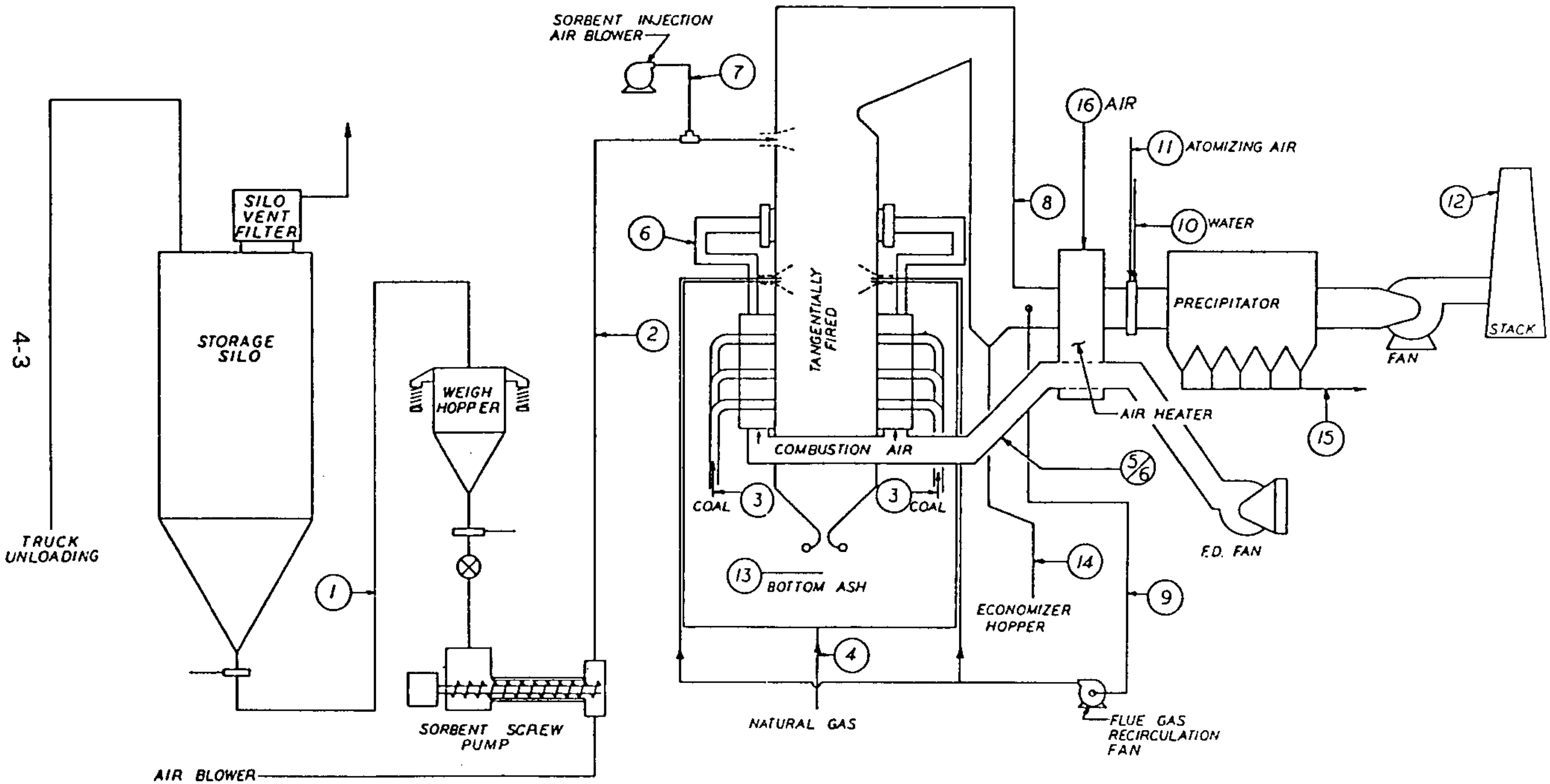


Figure 4-2. Hennepin Unit #1 GR-SI Process Flow Diagram

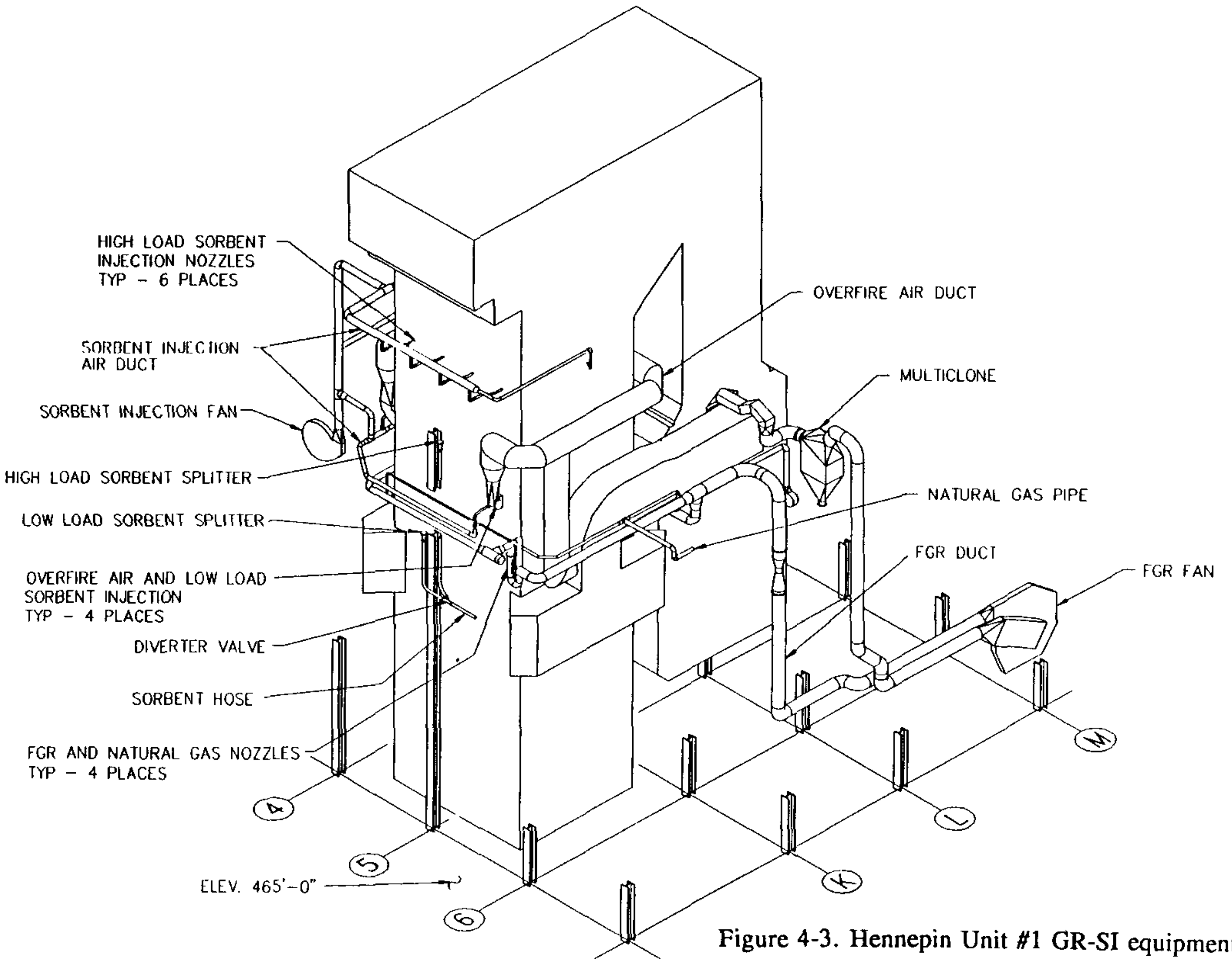


Figure 4-3. Hennepin Unit #1 GR-SI equipment isometric drawing

TABLE 4-1. HENNEPIN UNIT #1 GR-SI MASS BALANCES

Stream No.	1	2	3	4	5	6	7	8
Stream Name	Sorbent	Trans. Sorbent	Coal	Natural Gas	Burner Air	Overfire Air	Sorbent Air	Flue Gas
Rate	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
CH_4				6,150				
C			33,863					
H			2,272					
O			4,270					
N			596					
S			1,614					
Ash	231	231	5,472					11,538
H_2O		16	9,153		6,338	1,983	234	51,844
N_2		923			375,173	115,884	13,809	506,330
O_2		279			113,636	35,041	4,181	23,154
CO_2								140,668
CO								28
NOx								178
SO_2								2,109
$Ca(OH)_2$	5,856	5,856						
Total	6,087	7,305	57,240	6,150	495,147	152,908	18,224	735,849
Temperature, °F	60	70	60	60	534	534	70	700
Pressure, psia.	14.7	14.9	14.7	15.7	14.9	14.9	15.7	14.5

TABLE 4-1 (cont.) HENNEPIN UNIT #1 GR-SI MASS BALANCES

Stream No.	9	10	11	12	13	14	15
Stream Name	FGR	Humid. Water	Atomizing Air	Stack Gas	Bottom Ash	Economizer Ash	Air Leakage
Rate	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
CH_4							
C							
H							
O							
N							
S							
Ash	333			17	1,124	288	
H_2O	1,636	12,500	64	64,741			333
N_2	15,990		3,789	529,761			19,642
O_2	754		1,147	30,248			5,947
CO_2	4,406			140,668			
CO	1			28			
NOx	7			178			
SO_2	48			2,109			
$Ca(OH)_2$							
Total	23,175	12,500	5,000	767,750	1,124	288	25,922
Temperature, °F	700	80	80	274	-	700	115
Pressure, psia.	15.6	95	115	14.7	14.7	14.7	15.0

TABLE 4-2A
HENNEPIN COAL FIRED UNIT
MASS AND ENERGY BALANCE
(FURNACE)

Basis: 60F & H2O(l)		Ca/S =	1.57	SO2 Capture =	34.6%
		TEMP.F	LB/HR	BTU/LB	BTU/HR
INPUT:					
FEED		60			
10,512	HHV IGT *calc.*				
10,632	HHV actual				
Comp.	wt%				
C	59.16		33863		
H	3.97		2272		
O	7.46		4270		
N	1.04		595		
S	2.82		1614		
Cl	0.00		0		
Ash	9.56		5472		
H2O(l)	15.99		9153		
total	*100.00*				
Subtotal	608.57	MMBtu/hr	57240	0.0	0
NATURAL GAS		60			
21721	Btu/lb (HHV)				
as CH4	18.0%	of energy	6150	0.0	0
	133.58	MMBtu/hr			
SORBENT	wt%	70			
Ca(OH)2	96.2		5856		
Ash	3.8		231		
Subtotal	100.0		6087	4.5	27393
SORB. AIR	wt%	70			
O2	22.94		4460	2.1	9571
N2	75.77		14732	2.4	35663
H2O(v)	1.28		250	1064.0	265619
(MW =	28.797)				
Subtotal	4270	scfm	19442		310853
COMB. AIR	wt%	534			
O2	22.94		148677	107.4	15960910
N2	75.77		491057	118.3	58087245
H2O(v)	1.28		8321	1276.7	10623622
(MW =	28.797)				
Subtotal	142339	scfm	648055		84671777
HEAT OF COMBUSTION					741199546
TOTAL			736974		826209568
OUTPUT:					
FLUE GAS	vol%	3470			
O2	*2.91*	*3.29%*	*23154*	*883.5*	*20455676*
N2	72.67		506330	989.7	501138211
H2O(v)	11.57		51844	3040.7	157641647
CO2	12.85		140668	966.1	135895331
SO2,ppmv	1324		2109	654.0	1379316
HCl,ppmv	0		0	627.7	0
NOx,ppmv	155	0.24	178	966.1	171852
CO,ppmv	41	lb/MMBtu	28	997.1	28183
Ash/C,S			11538	750.2	8656044
(MW =	29.119)				
Subtotal	100.00		735849		825366259
RESIDUE		3470			
Carbon	1.20%		14		
S	1.44%		16		
Ash			1094		
Subtotal			1124	750.2	843309
HEAT LOS	0.00%				0
TOTAL			736974		826209568

Mass Closure = 100.00% Energy Closure = 100.00%

TABLE 4-2B
HENNEPIN COAL FIRED UNIT
MASS AND ENERGY BALANCE
(BOILER)

Basis: 60F & H2O(l) Economizer Ash 2.50% of total ash

		TEMP.F	LB/HR	BTU/LB	BTU/HR
INPUT:					
FLUE GAS	vol%	3470			
O2	2.91		23154	883.5	20455676
N2	72.67		506330	989.7	501138211
H2O(v)	11.57		51844	3040.7	157641647
CO2	12.85		140668	966.1	135895331
SO2,ppmv	1324		2109	654.0	1379316
HCl,ppmv	0		0	935.4	0
NOx,ppmv	155		178	966.1	171852
CO,ppmv	41		28	997.1	28183
Ash w/Carbon			11538	750.2	8656044
(MW =	29.119)		------------------		-------------------------
Subtotal	100.00		735849		825366259
BOILER FEEDWATER		475			
H2O(l)			558272	446.9	249514167
R. STEAM @ 495psig		720	484400	1339.9	649066936
			======		========
TOTAL			1778522		1723947362
OUTPUT:					
FLUE GAS	vol%	700			
O2	2.91		23154	147.3	3410670
N2	72.67		506330	161.4	81704031
H2O(v)	11.57		51844	1357.7	70389501
CO2	12.85		140668	150.2	21122405
SO2,ppmv	1324		2109	107.9	227602
HCl,ppmv	0		0	134.7	0
NOx,ppmv	155		178	150.2	26711
CO,ppmv	41		28	164.7	4654
Ash w/Carbon			11250	140.8	1583975
(MW =	29.119)		------------------		-------------------------
Subtotal	100.00		735561		178469549
ECONOMIZER ASH		700	288	140.8	40615
STEAM @ 1500psig		1005			
H2O(v)			550280	1462.0	804531027
R. STEAM @ 445psig		1005	492392	1495.9	736589506
BLOWDOWN @ 0.0%			0		0
HEAT LOSS	0.52%				4316666
			======		========
TOTAL			1778522		1723947362

Mass Closure = 100.00% Energy Closure = 100.00%

TABLE 4-2C
HENNEPIN COAL FIRED UNIT
MASS AND ENERGY BALANCE
{AIR HEATER}

Basis: 60F & H2O(l) AIR LEAKAGE = 4.00%

		TEMP.F	LB/HR	BTU/LB	BTU/HR
INPUT:					
FLUE GAS	vol%	700			
O2	2.91		23154	147.3	3410670
N2	72.67		506330	161.4	81704031
H2O(v)	11.57		51844	1357.7	70389501
CO2	12.85		140668	150.2	21122405
SO2,ppmv	1324		2109	107.9	227602
HCl,ppmv	0		0	134.7	0
NOx,ppmv	155		178	150.2	26711
CO,ppmv	41		28	164.7	4654
Ash w/Carbon			11250	140.8	1583975
(MW =	29.119)		----------		----------
Subtotal	100.00		735561		178469549
AIR	wt%	115			
O2	22.94		154624	11.9	1837133
N2	75.77		510700	13.4	6825663
H2O(v)	1.28		8654	1083.8	9378766
(MW =	28.797)		----------		----------
Subtotal			673977		18041562
			======		========
TOTAL			1409538		196511111
OUTPUT:					
FLUE GAS	vol%	352			
O2	3.53		29101	65.0	1890913
N2	72.84		525972	72.2	37952251
H2O(v)	11.23		52177	1191.1	62146266
CO2	12.40		140668	64.1	9015726
SO2,ppmv	1277		2109	46.5	97978
HCl,ppmv	0		0	59.1	0
NOx,ppmv	150		178	64.1	11401
CO,ppmv	39		28	74.6	2109
Ash w/Carbon			11250	64.2	722688
(MW =	29.102)		----------		----------
Subtotal	100.00		761483		111839334
		534			
AIR	wt%	534			
O2	22.94		148677	107.4	15960910
N2	75.77		491057	118.3	58087245
H2O(v)	1.28		8321	1276.7	10623622
(MW =	28.797)		----------		----------
Subtotal	142,339 scfm		648055		84671777
HEAT LOSS @ 0%					0
			======		========
TOTAL			1409538		196511111

Mass Closure = 100.00% Energy Closure = 100.00%

TABLE 4-2D
HENNEPIN COAL FIRED UNIT
MASS AND ENERGY BALANCE
{HUMIDIFICATION}

Basis: 60F & H2O(l)

		TEMP.F	LB/HR	BTU/LB	BTU/HR
INPUT:					
FLUE GAS	vol%	352			
O2	3.53	3.97%	29101	65.0	1890913
N2	72.84	dry	525972	72.2	37952251
H2O(v)	11.23		52177	1191.1	62146266
CO2	12.40		140668	64.1	9015726
SO2,ppmv	1277		2109	46.5	97978
HCl,ppmv	0		0	59.1	0
NOx,ppmv	150		178	64.1	11401
CO,ppmv	39		28	74.6	2109
Ash/CaO/CaSO4/C			11250	64.2	722688
(MW =	29.102)		------------------		------------------------
Subtotal	100.00		761483		111839334
HUMID. WATER		80			
H2O(l)	25 GPM		12500	52.0	649875
DFN AIR	wt%	80			
O2	22.94		1147	4.3	4930
N2	75.77		3789	4.8	18360
H2O(v)	1.28		64	1068.4	68592
(MW =	28.797)		------------------		------------------------
Subtotal	1098 scfm		5000		91882
			======		========
TOTAL			778983		112581090
OUTPUT:					
FLUE GAS	vol%	281			
O2	3.55	4.10%	30248	48.7	1474284
N2	70.97	dry	529761	54.3	28773539
H2O(v)	13.49	127	64741	1158.3	74987818
CO2	11.99	sat.	140668	47.7	6715752
SO2,ppmv	1235	1.98	2109	34.7	73098
HCl,ppmv	0	psia	0	44.3	0
NOx,ppmv	145	154	178	47.7	8493
CO,ppmv	38	approach	28	56.7	1602
Ash w/Carbon			11250	48.6	546505
(MW =	28.810)		======		========
TOTAL	100.00		778983		112581090

Mass Closure = 100.00% Energy Closure = 100.00%

TABLE 4-2E
HENNEPIN COAL FIRED UNIT
MASS AND ENERGY BALANCE
(ELECTROSTATIC PRECIPITATOR)

Basis: 60F & H2O(l) ESP EFFICIENCY = 99.85 %

		TEMP.F	LB/HR	BTU/LB	BTU/HR
INPUT:					
FLUE GAS	vol%	281			
O2	3.55		30248	48.7	1474284
N2	70.97		529761	54.3	28773539
H2O(v)	13.49		64741	1158.3	74987818
CO2	11.99		140668	47.7	6715752
SO2,ppmv	1235		2109	34.7	73098
HCl,ppmv	0		0	44.3	0
NOx,ppmv	145		178	47.7	8493
CO,ppmv	38		28	56.7	1602
Ash w/Carbon			11250	48.6	546505
(MW =	28.810)		======		========
TOTAL	100.00		778983		112581090
OUTPUT:					
FLUE GAS	vol%	273			
O2	3.55	4.10	30248	47.1	1423929
N2	70.97	dry	529761	52.5	27801283
H2O(v)	13.49		64741	1154.9	74770123
CO2	11.99		140668	46.1	6481745
SO2,ppmv	1235		2109	33.5	70562
HCl,ppmv	0		0	42.8	0
NOx,ppmv	145		178	46.1	8197
CO,ppmv	38		28	54.8	1550
Ash w/Carbon		0.023	17	47.0	792
(MW =	28.810)	lb/MM Bt	----------		----------
Subtotal	100.00		767750		110558182
	168,554	scfm			
ESP SOLIDS		273			
Ash w/Carbon&Sulfur			11233	47.0	527506
			----------		----------
Subtotal			11233		527506
HEAT LOS	2.00%				1495402
			======		========
TOTAL			778983		112581090

Mass Closure = 100.00% Energy Closure = 100.00%

The humidification mass and energy balance reflects the effect of water atomization and evaporation to reduce the inlet gas temperature to the ESP to improve performance by decreasing fly ash resistivity. An overall mass and energy balance for the GR-SI system applied to Hennepin Unit #1 is shown in Table 4-3.

4.1.2 GR System

The design of the GR system includes three integrated systems: 1) natural gas injection, 2) FGR, and 3) OFA injection. Natural gas is mixed with FGR at the gas injection nozzles located above the tangentially fired coal burners. The nozzles were designed so that orientation of gas injection would be varied in accord with the changing orientation of the tangentially-fired coal burners.

A 14" (36 cm) natural gas header existed at the Station and a 6" (15 cm) pipe tie-in was made to this supply header to provide the natural gas for the GR system. The 6" pipe supplied gas to a control and metering station and from this station natural gas was distributed to four gas injection nozzles located on the corners of the furnace, above the tangential coal-fired burners. The natural gas valve train, common to all of the injection nozzles, includes flow metering and control equipment, and safety shut-off valves. The maximum design and normal conditions for natural gas injection operation is shown below:

	Normal	Design (max.)
Natural Gas Flow (lb/hr)	6,284	9,386
Natural Gas Flow (scfm)	2,244	3,352
Natural Gas Btu Input (10^6 Btu/hr)	136	204
Flue Gas Recirc. Flow (lb/hr)	23,000	27,500
Flue Gas Recirc. Flow (scfm)	10,890	13,020
Natural Gas Pressure (psig)	1	1.8
Flue Gas Pressure (in.W.C.)	24	34

TABLE 4-3. HENNEPIN UNIT #1 OVERALL MASS AND ENERGY BALANCE

w/GR-SI @ 71 MWe Net Power Out

Basis: 60°F & H2O as liquid

Input:	Lb/hr	Btu/hr
Furnace -		
Coal, incl. heat of combustion	57,240	608,571,983
Natural Gas, incl. heat of combustion	6,150	133,581,550
Burner Air	533,900	14,291,861
Overfire Air	114,155	3,055,795
Sorbent Injection Air	19,442	310,853
Sorbent	6,087	27,393
Air Heater -		
Air Leakage	25,922	693,906
Humidification -		
Atomizing Air	5,000	91,882
Water	12,500	649,875
Total	**780,396**	**761,275,098**

Output:	Lb/hr	Btu/hr
Furnace -		
Bottom Ash, incl. heat of combustion	1,125	1,034,107
Boiler/Economizer -		
Energy to Steam Cycle		642,539,430
Economizer Ash, incl. heat of	288	59,694
ESP -		
Fly Ash, incl. heat of combustion	11,233	1,271,617
Stack -		
Flue Gas	767,750	110,558,182
System Heat Loss -		5,812,068
Total	**780,396**	**761,275,098**

An FGR system was installed, withdrawing hot flue gas from the economizer outlet with an FGR fan and routing the flue gas to each of the four natural gas injectors. The purpose of using the FGR was to increase mixing in the furnace to assure the establishment of a an adequate reducing zone in the furnace for the destruction of NO_x. The FGR system included a multiclone for particulate removal upstream of the FGR fan. OFA was supplied from the existing hot secondary combustion air windbox. The existing windbox pressure was adequate, so booster fans were not required. Piping and instrument diagrams of the GR system, including the FGR and OFA system are shown in Figures 4-4 and 4-5.

The installation of the OFA ports required modifications to the furnace boiler tubes for wall penetrations. The OFA is injected through four ports located in the corners of the furnace. OFA is extracted from two secondary air ducts which have sufficiently high static pressure, therefore the system did not require an OFA booster fan. The flow of OFA through each port is controlled by modulated butterfly control valves. The OFA ports are air cooled when the OFA system is not in service. All of the OFA ducts were designed with expansion joints. The ducts were designed for a temperature of 600°F (316°C), and ∓35 in. W. C. (8.7 kPa).

4.1.3 Sorbent Injection System

The SI system was designed to store, meter, and convey micron-sized sorbent to the injection nozzles in the upper furnace. The SI system piping and instrumentation diagrams are shown in Figures 4-6 and 4-7. The system was also designed to accommodate a wide range of operating conditions. The SI system is comprised of the following major components: sorbent storage silo, weigh hopper, rotary valve feeder, screw pump, air transport blower, conveying line, sorbent splitter, SI air fan, and injection nozzles.

Sorbent is delivered to the plant in pneumatic tankers with capacities of 20-25 tons.

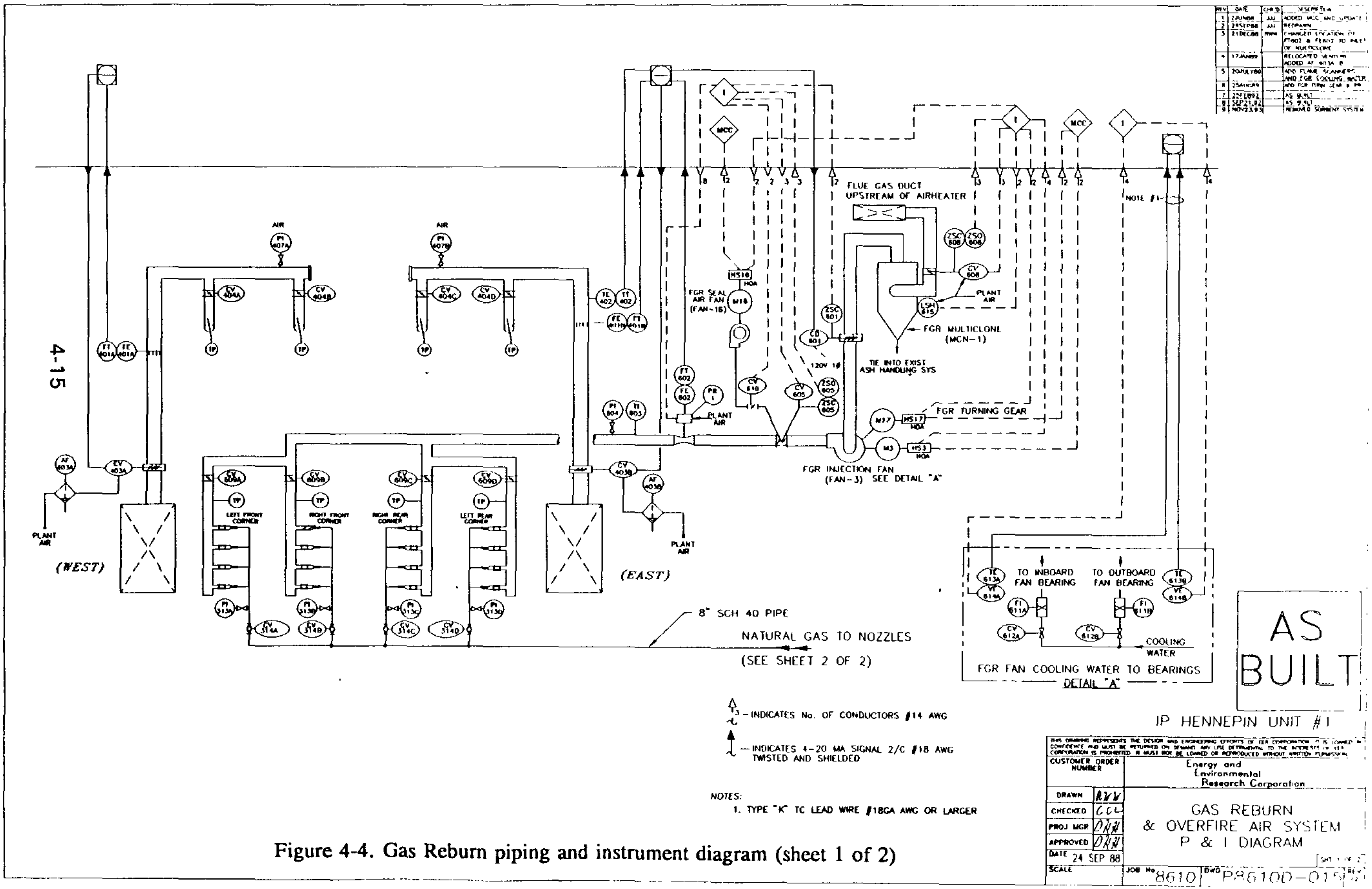
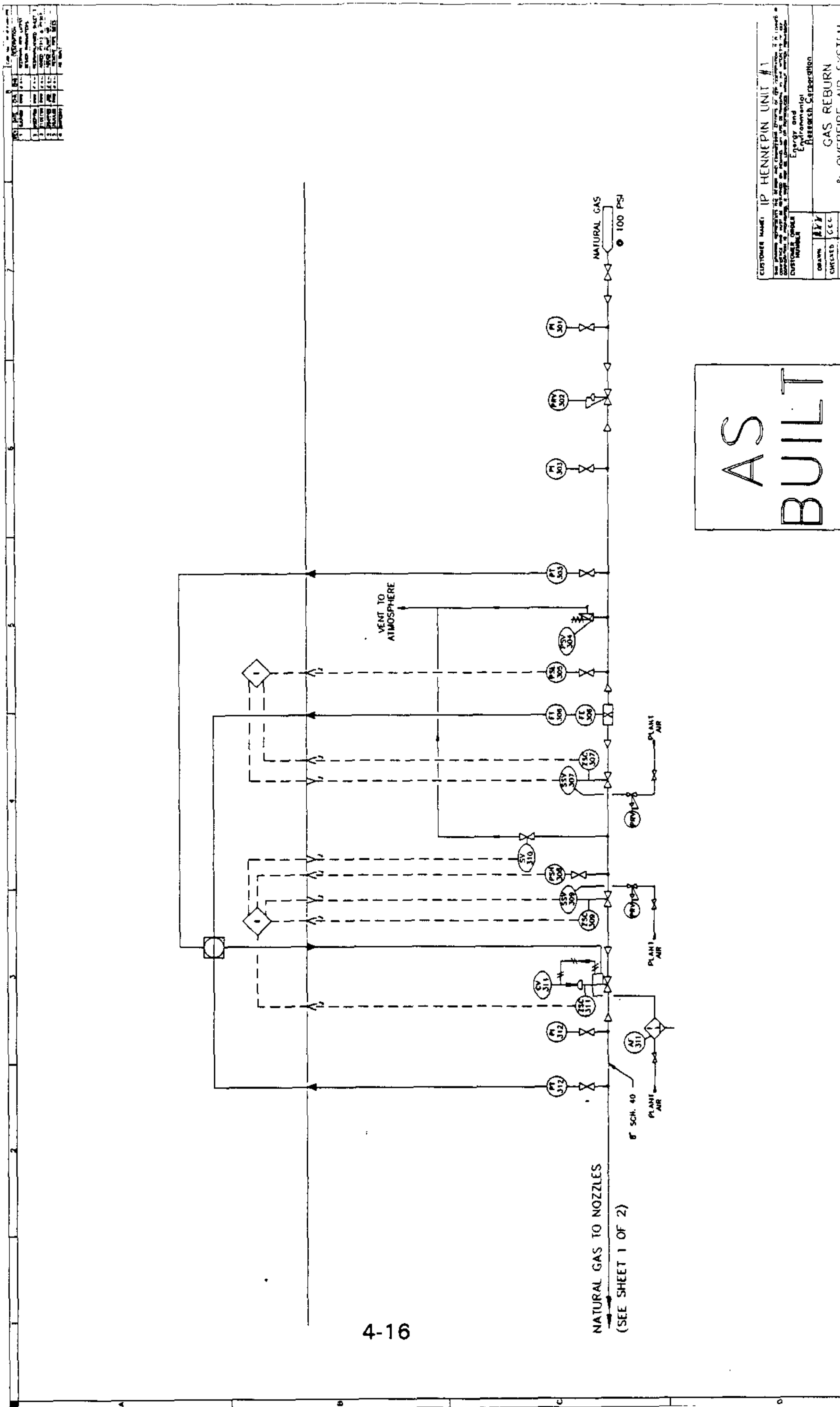


Figure 4-4. Gas Reburn piping and instrument diagram (sheet 1 of 2)


IP HENNEPIN UNIT #1
Energy and Environmental Research Corporation
GAS REBURN
AS BUILT
NATURAL GAS
@ 100 PSI
PI 301
PRV 302
PI 303
PT 303
VENT TO ATMOSPHERE
PSV 304
PSL 305
FT 306
FE 306
PLANT AIR
ZSC 307
SSV 307
SV 310
PSH 308
SSV 309
ZSC 309
CV 311
ZSC 311
PI 312
AF 311
PT 312
6" SCH. 40
NATURAL GAS TO NOZZLES
(SEE SHEET 1 OF 2)

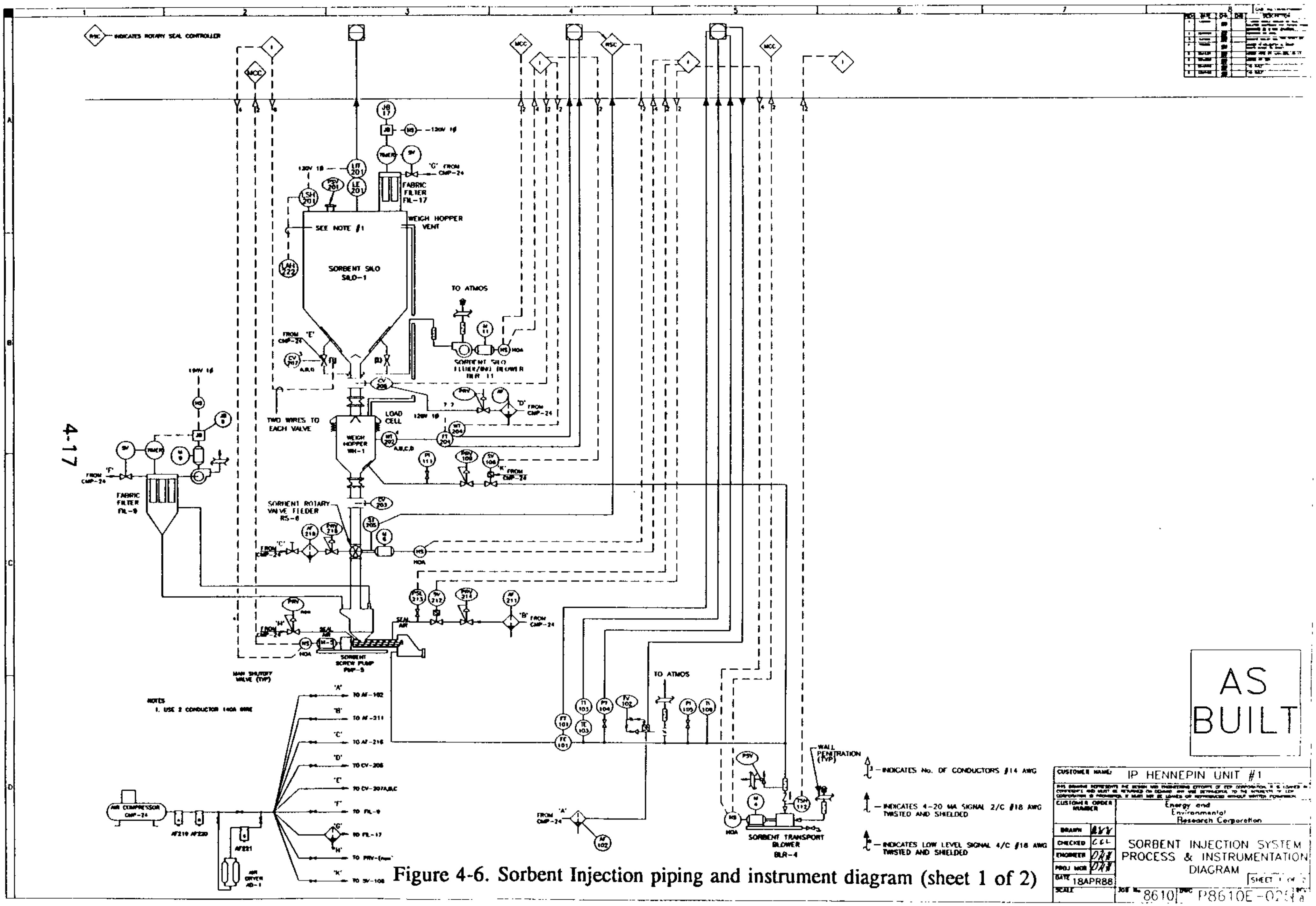
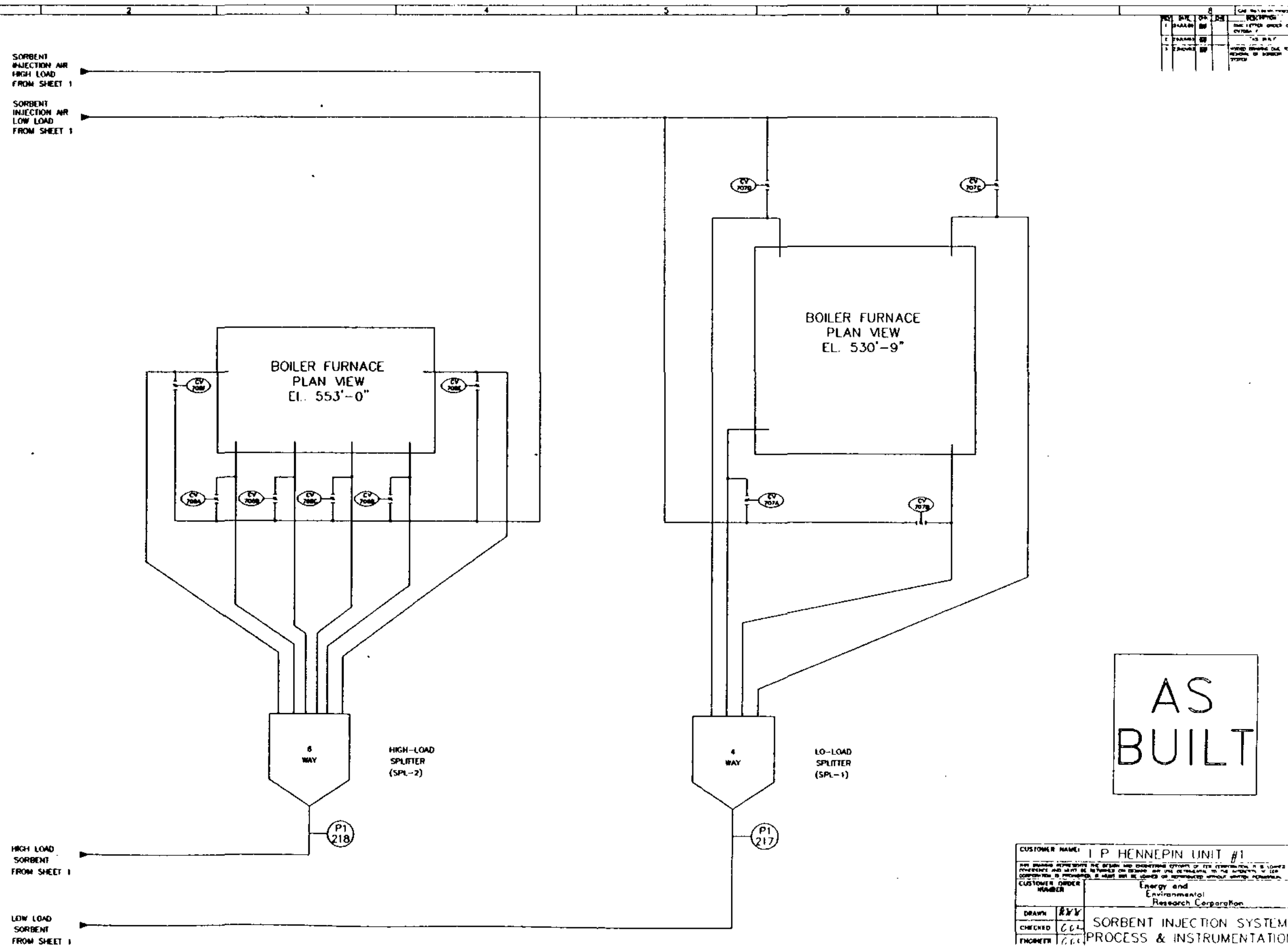


Figure 4-6. Sorbent Injection piping and instrument diagram (sheet 1 of 2)


SORBENT INJECTION AIR HIGH LOAD FROM SHEET 1
SORBENT INJECTION AIR LOW LOAD FROM SHEET 1
BOILER FURNACE PLAN VIEW EL. 553'-0"
BOILER FURNACE PLAN VIEW EL. 530'-9"
6 WAY
HIGH-LOAD SPLITTER (SPL-2)
4 WAY
LO-LOAD SPLITTER (SPL-1)
PI 218
PI 217
HIGH LOAD SORBENT FROM SHEET 1
LOW LOAD SORBENT FROM SHEET 1
AS BUILT
CUSTOMER NAME: I P HENNEPIN UNIT #1
CUSTOMER ORDER NUMBER
Energy and Environmental Research Corporation
DRAWN
CHECKED
ENGINEER
SORBENT INJECTION SYSTEM PROCESS & INSTRUMENTATION

A truck mounted blower was used to convey the sorbent, via a pipeline, to a sorbent storage silo. Conveying air is vented through a silo vent filter. From the silo sorbent is controlled by a variable speed rotary valve feeder into a pneumatic sorbent screw pump that transports the sorbent to the furnace injectors. Load cells on the silo are used to determine sorbent flow rate into the system. Transport air to the sorbent screw pump is provided by a positive displacement blower. The sorbent is conveyed to flow splitters that provide sorbent to each of the six injectors mounted on the upper furnace front and side walls. At the injectors, additional transport air is added to yield the necessary mass momentum to provide for good furnace penetration and mixing. The SI system is designed to inject sorbent into the furnace at a rate corresponding to a Ca/S (coal) molar ratio of 2.0.

4.1.4 Humidification System

The humidification system located on the inlet to the electrostatic precipitator (ESP) was designed to cool the flue gas to within 70°F (21°C) of the saturation temperature, over a range of boiler loads from 12 MWe net to full load at 71 MWe net. The humidification system piping and instrumentation diagrams are shown in Figures 4-8 and 4-9.

The water used for the humidification system is supplied from the existing plant service water supply. A tie-in was made to the existing line that fed a the suction of a new booster water pump. A basket type strainer was placed in the suction to the pump to prohibit debris from entering the pump. The pump delivered water to the humidification nozzles at nominally 100 psig.

The nozzles used for humidification were dual fluid nozzles. Atomizing air at nominally 125 psig (862 kPa) was supplied to the nozzles from three rotary screw air compressors. Six lances were inserted into the flue gas ducts to supply air and water to the dual fluid nozzles and to allow for a good distribution of water droplets

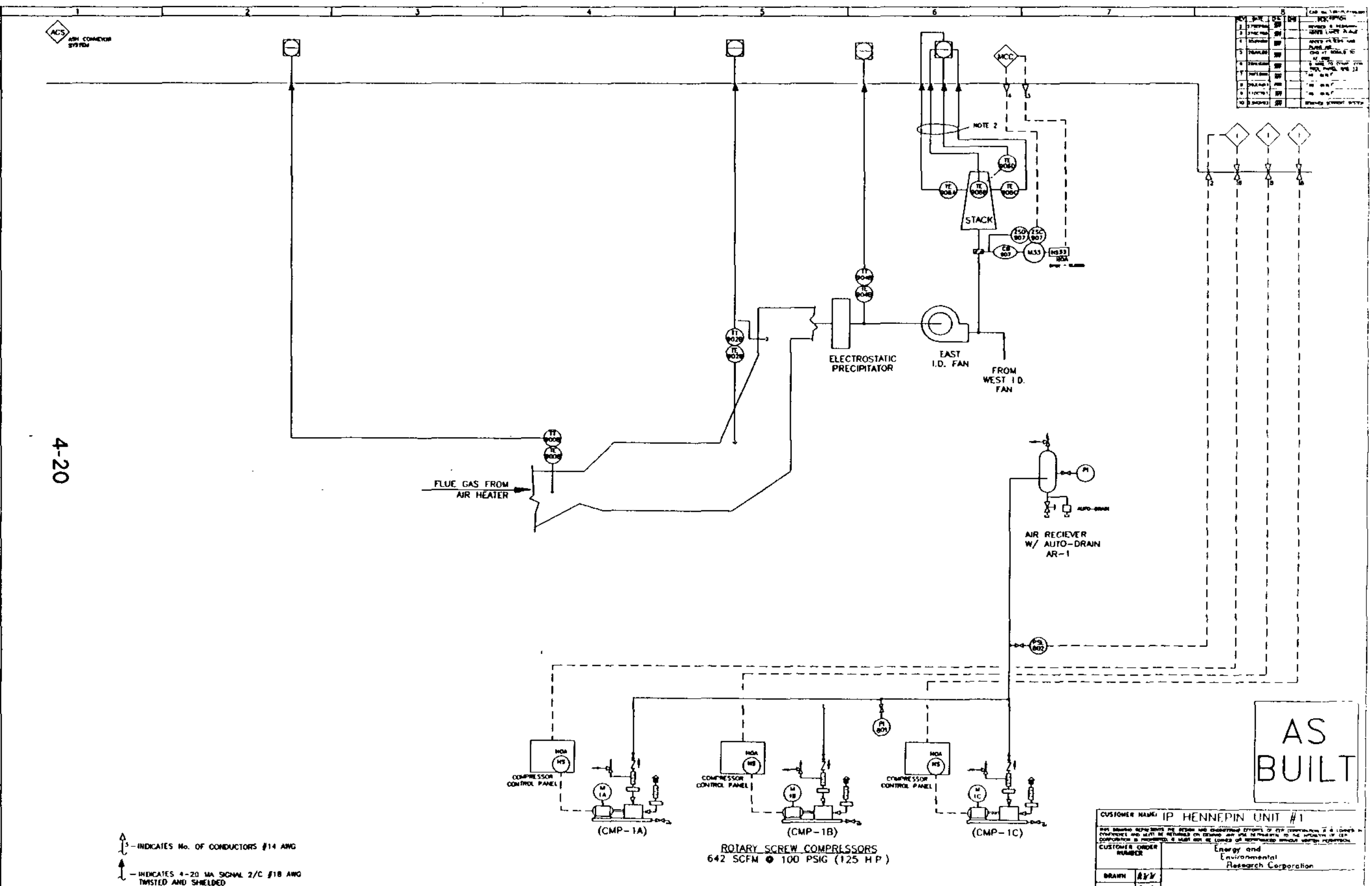


Figure 4.8. Humidification System

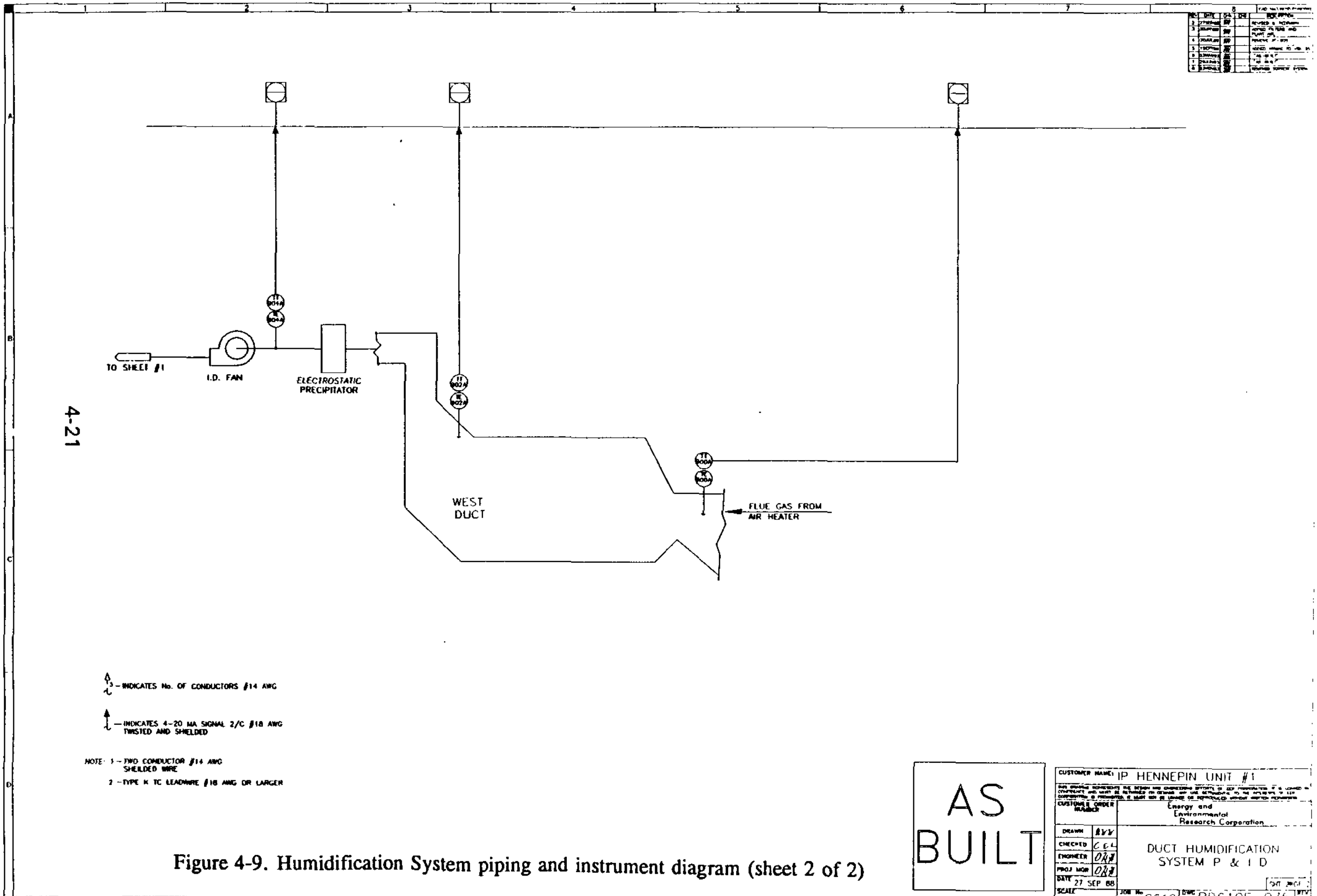


Figure 4-9. Humidification System piping and instrument diagram (sheet 2 of 2)

throughout the cross-sectional area of the flue gas ducts. Each lance could accommodate up to six nozzles.

Humidification takes place in an enlarged section of ductwork downstream of the existing air heater and upstream of the ESP. Due to the enlargement of the duct it was equipped with two ash hoppers and a drag chain conveyor to remove any ash that might settle out in the enlarged duct.

4.1.5 Ash/Sorbent Waste Handling

Hennepin Unit #1 is equipped with a United Conveyor wet sluicing system. The wet system uses high pressure water (~130 psig or 896 kPa) and an ejector to create a vacuum, drawing fly ash and transport air from air intakes located upstream of the ESP hoppers and transporting the fly ash to an air separator where conveying air is separated from the fly ash slurry. The sluicing system mixes fly ash with water at a ratio of 25 lb H_2O/1 lb fly ash. The ash is then sluiced to an on-site settling pond prior to discharge to the Illinois River. The sluice water is treated with CO_2 for pH adjustment. To accommodate the high-calcium ash associated with the SI system, United conveyor designed a new system with a built-in ram scraper to minimize the buildup of scale.

The Hennepin Station Unit 1 had an existing wet sluicing system in place and operating prior to the GR-SI installation. As part of the GR-SI retrofit the wet sluicing system was modified to accommodate the higher ash generation rate and the different characteristics of the ash generated under SI operation. As mentioned in the report a new United Conveyor hydrovac was purchased and installed that was equipped with an internal ram scraper. The hydrovac is the device used to create a vacuum in the system to pull ash from the collection hoppers. Water is pumped to the hydrovac and flows through an eductor to provide the vacuum. The conveying air and ash is pulled into the hydrovac where it mixes with the motive water. At this point of mixing within the hydrovac, scale formation is prevalent. The ram scraper periodically removes the scale to prevent the hydrovac from plugging and losing vacuum. Other modifications to the wet sluicing system included the addition of ash pick-up points. New ash collection hoppers were incorporated into the humidification ductwork and equipped with screw conveyors to discharge the ash into ash conveying lines.

As a result of the carbonate content of the ash, reaction of the SI ash with the sluice water results in a pH increase from the 6 - 8 range to above 12. Hennepin's discharge permit requires that the pond discharge have a pH between 6 and 9. In order to control the pond discharge pH, EER installed a carbon dioxide injection system as part of the Hennepin GR-SI retrofit. Gaseous CO_2 was injected into the sluice system piping to the ash pond to reduce pH of the sluice water going into the ash pond.

4.1.6 Sootblowing System Modifications

The boiler is equipped with wallblowers in the radiant furnace and retractable sootblowers in the convective pass. There are eight wallblowers (type IR) in the furnace, which are used on an as-needed basis to control slag deposits, and eight sootblowers (type IK) in the convective passes. These sootblowers utilize compressed air at 350 psig (2,413 kPa). With the installation of the SI technology, a total of eight additional sootblowers (type IK) were added to the convective passes. With the addition of the SI system, it was expected that the sootblowing requirement would double.

4.1.7 Auxiliary Power

The power distribution system was designed to supply power to GR-SI system auxiliaries, making provision for overload and fault protection. The maximum peak demand for auxiliary power to the GR-SI system is 765 kWe. Assuming the actual power demand is 75% of the peak demand, the auxiliary power for the GR-SI system would be about 0.8% of total power output at full load.

4.1.8 Equipment List

Gas Reburning

Valve Train Equipment:

1 - 6" Shut-off valve, mfr. Rockwell

1 - 3" Pressure reducing valve, C.I. const., mfr. Fisher, Tag No. PRV - 302

1 - 6" Pressure relief valve, C.I./S.S. trim const., mfr. Fisher, Tag No. PSV-304

1 - 8" Gas flowmeter, mfr. Rockwell, Tag No. FE-306, FT-306

2 - 8" Gas safety shut-off valves, mfr. DeZurik, Tag Nos. SSV-307, SSV-309

1 - 2" Gas vent valve, mfr. ASCO, Tag No. SV-310

1 - 6" Gas flow control valve, mfr. Fisher, Tag No. CV-311

4 - Gas nozzles w/4 ports ea., design - 210 scfm/nozzle, mfr. EER, (details proprietary)

Flue Gas Recirculation:

1 - Multiclone, mfr. Western Precipitator, Size 24-6, Tag No. Mcn-1

1 - FGR fan, design - 200 hp, 13,020 acfm @ 690 °F w/40" W.C. diff. press., Tag No. Fan-13

Overfire Air:

2 - Overfire air ports (air cooled), mfr. EER (details proprietary)

2 - Flow control dampers w/ Beck electric drives, Tag Nos. CV-403A, CV-403B

Sorbent Injection

1 - Storage silo, 26' dia. x 40' w/60°conical hopper, Tag No. Silo-1

1 - Weigh hopper, 5' dia. x 8'9" w/60° conical hopper, Tag No. WH-1

1 - Dust collector, 180 sq. ft. bag area, reverse jet, mfr. Flex-Kleen, Tag No. Fil-9

1 - 8" Sorbent screw pump, 25 hp, 0-931 cf/hr, mfr. Fuller, Tag No. Pmp-5

1 - Sorbent transport blower, 75 hp, 760 cfm @ 15 psig, mfr. Spencer, Tag No. Blr-4

10 - Coaxial jet sorbent injectors, C.S./S.S., designed by EER (details proprietary)

1 - Sorbent injection air fan, 60 hp, 5,650 scfm @ 35" W.C. diff. press., mfr. Garden City, Tag No. Fan-7

1 - Sorbent injection nozzle cooling fan, 1/2 hp, mfr. Clarage, Tag No. Fan-8

1 - Sorbent equipment air compressor, 30 hp, 130 scfm @ 100 psig, mfr. LeROI Dresser, Tag No. Cmp-24

1 - Air dryer, 124 scfm compressed air, mfr. Hankison, Tag No. AD-1

1 - CO_2 injection system for pH control

Humidification System

1 - Water pump, C.I. w/Bronze impeller, 3 hp, 60 gpm @ 43 psi diff. press., mfr. Peerless, Tag No. Pmp-2

3 - Air compressors, 200 hp, 870 scfm @ 125 psig, mfr. Ingersoll-Rand, Tag Nos. Cmp-1A, Cmp-1B, Cmp-1C.

1 - Air receiver tank, 150 psig, 300 cu. ft., mfr. Ingersoll-Rand, Tag No. AR-1

6 - Dual fluid humidification nozzle lances, S.S. const., 1.76 gpm/nozzle, mfr. EER

3 - Fly ash drag chain conveyor, 1 hp, 100 cfh, mfr. Beaumont, Tag Nos. AC-18, AC-19, AC-20

4.2 Lakeside Unit #7 Detailed Process Design

The City Water Light and Power Lakeside Station is located in Springfield, Illinois.

Figure 4-10 is a plot plan of the plant. The GR-SI system was applied to Lakeside Unit #7, a 30 MWe (net) cyclone-fired boiler that burns medium-to-high sulfur Illinois coal. The retrofit of the GR-SI systems involved the installation of gas piping and injectors, an FGR system, an OFA system, a sorbent storage silo, and a pneumatic conveying system for transporting sorbent to the boiler furnace injectors. Figure 4-11 is an equipment isometric drawing of the GR-SI system installed on Lakeside Unit #7. An overall process flow diagram is provided in Figure 4-12.

4.2.1 Mass and Energy Balances

Mass balances that correspond to the stream numbers shown in Figure 4-12 are shown in Table 4-4. Mass and energy balances around each of the subsystems (the furnace, boiler/economizer, air heater, and electrostatic precipitator) are shown in Tables 4-5A through 4-5D. The mass and energy balances are based on a full boiler load condition to produce 30 MWe net electrical power. The furnace mass and energy balance reflects the effect of the GR-SI technology on the system. An overall mass and energy balance for the GR-SI system applied to Lakeside Unit #7 is shown in Table 4-6.

4.2.2 GR System

The GR system was designed to convey, meter and inject natural gas through nozzles into the region above the refractory lined primary furnace (reburning zone). The Lakeside Station had no gas firing capability prior to this project, therefore the gas supplier installed a 6" (15 cm) high pressure header to the boiler house with a metering and pressure reducing station. An 8" (20 cm) tie-in line was then installed to carry the natural gas from this station to the reburning fuel flow/pressure regulation and metering system.

The natural gas train, common to all injection nozzles, incorporates a pressure

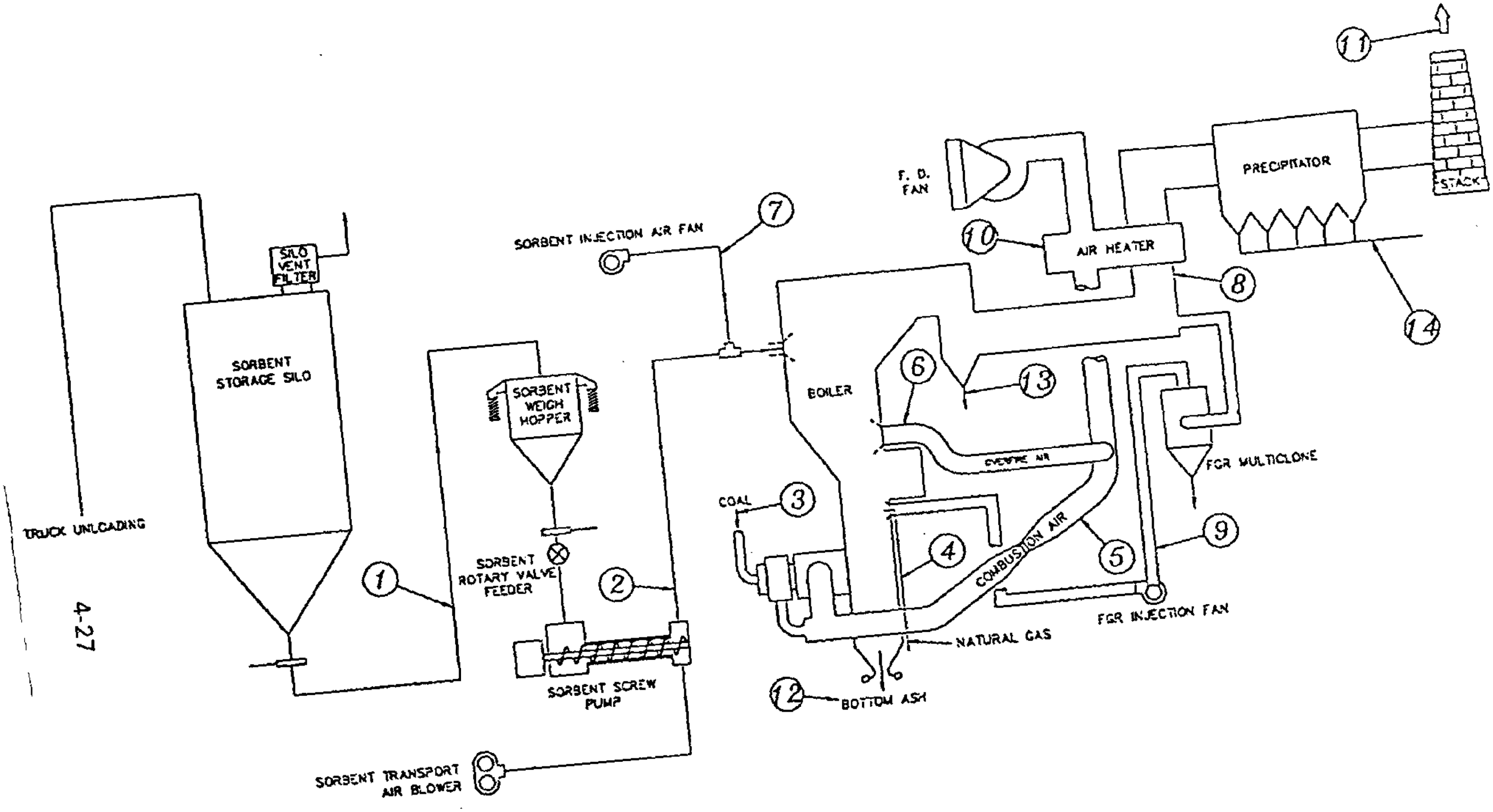
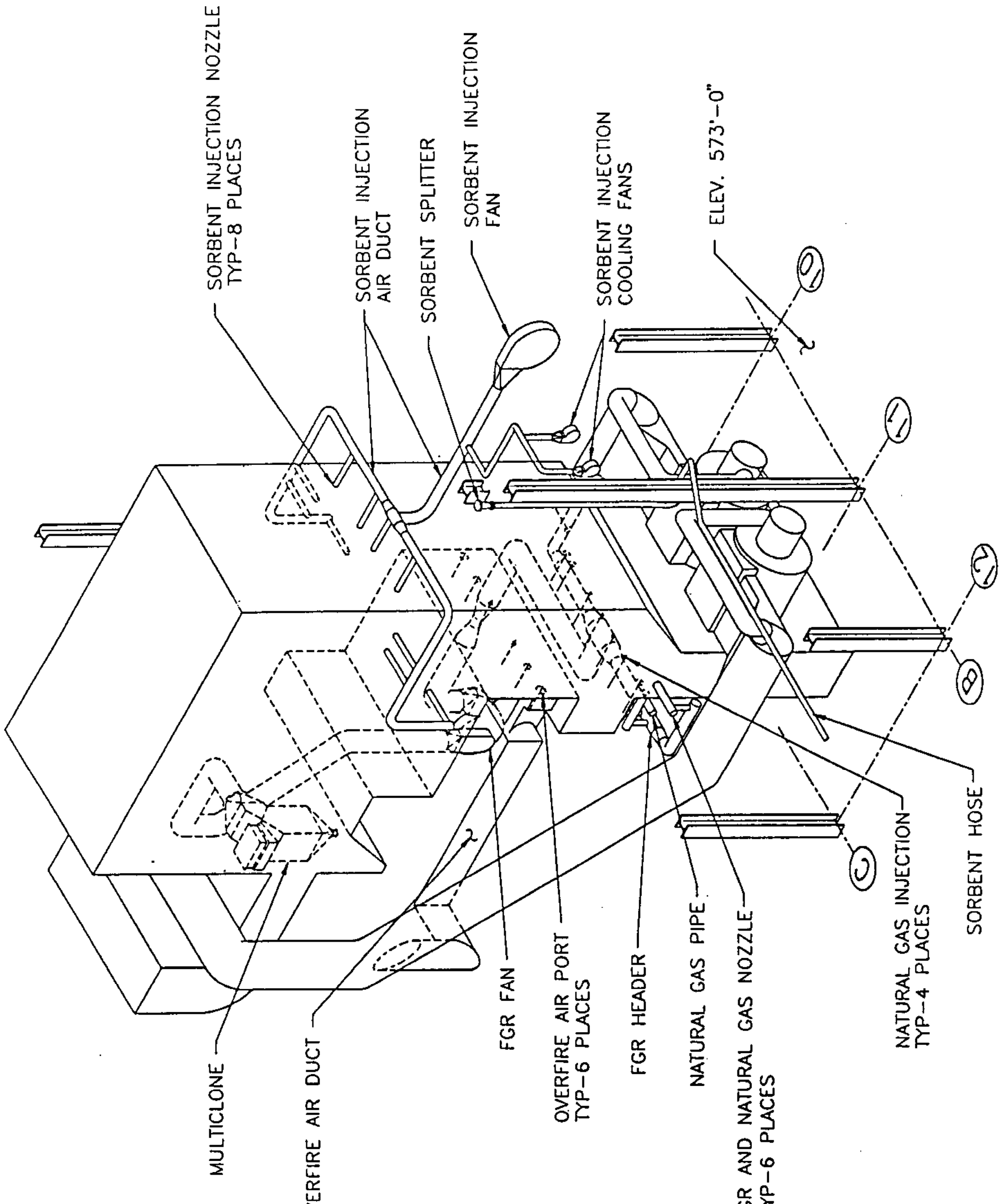


Figure 4-10. Lakeside Unit #7 GR-SI process flow diagram


SORBENT INJECTION NOZZLE
TYP-8 PLACES
SORBENT INJECTION
AIR DUCT
SORBENT SPLITTER
SORBENT INJECTION
FAN
SORBENT INJECTION
COOLING FANS
ELEV. 573'-0"
10
11
12
B
C
MULTICLONE
OVERFIRE AIR DUCT
FGR FAN
OVERFIRE AIR PORT
TYP-6 PLACES
FGR HEADER
NATURAL GAS PIPE
FGR AND NATURAL GAS NOZZLE
TYP-6 PLACES
NATURAL GAS INJECTION
TYP-4 PLACES
SORBENT HOSE

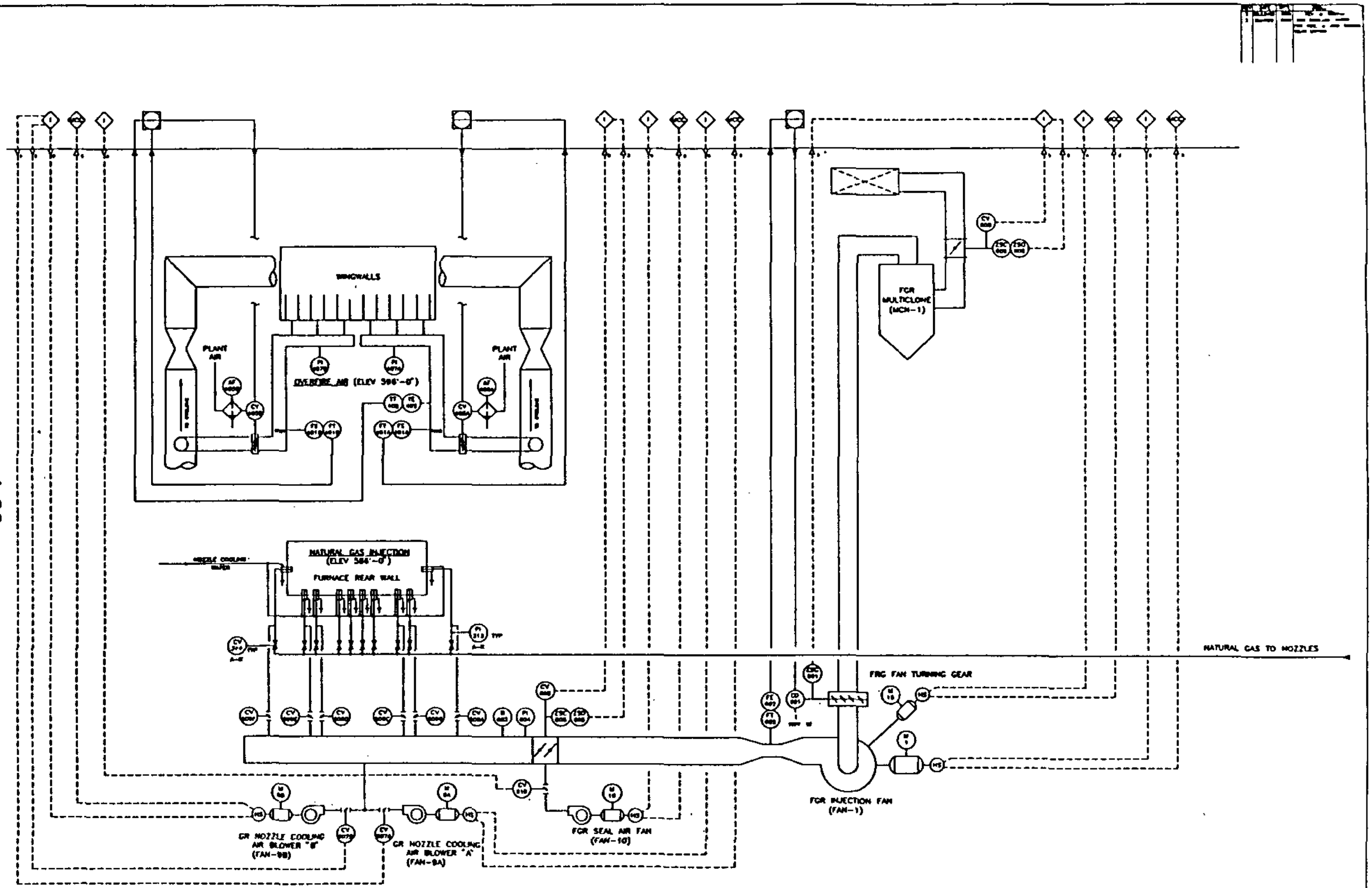


Figure 4-12. Lakeside Unit #7 Gas Reburning piping and instrument diagram

3 – INDICATES No. OF CONDUCTORS #14 AWG

– INDICATES 4-20 MA SIGNAL 2/C #14 AWG TWISTED AND SHIELDED

CWLP LAKESIDE UNIT #7

Energy and Environmental Research Corporation

GAS INJECTION
& OVERFIRE AIR SYSTEM
P & I DIAGRAM

DRAWN RVV
CHECKED CCL
APPROVED CCL
DATE 7 JULY 88
SH 1
P-8612F-015

TABLE 4-4. LAKESIDE UNIT #7 GR-SI MASS BALANCES

Stream No.	1	2	3	4	5	6	7
Stream Name	Sorbent	Trans. Sorbent	Coal	Natural Gas	Burner Air	OFA	Sorbent Air
Rate	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
CH_4				4,450			
C			17,310				
H			1,205				
O			2,279				
N			338				
S			941				
Ash	179	179	3,003				
H_2O		12	5,974		3,513	1,333	134
N_2		716			207,975	78,884	7,890
O_2		217			62,994	23,893	2,389
CO_2							
CO							
NOx							
SO_2							
$Ca(OH)_2$	4,544	4,544					
Total	4,723	5,668	31,050	4,450	274,482	104,110	10,413
Temperature, °F	60	70	60	60	473	473	70
Pressure, psia.	14.7	14.9	14.7	16.7	16.0	16.0	15.7

TABLE 4-4. (cont.) LAKESIDE UNIT #7 GR-SI MASS BALANCES

Stream No.	8	9	10	11	12	13	14
Stream Name	FG to AH	FGR	Air Leakage	Stack	Bottom Ash	Boiler Exit Ash	ESP Ash
Rate	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
CH_4							
C							
H							
O							
N							
S							
Ash	6,121	204		9	2,548	125	6,113
H_2O	31,742	1,463	729	32,471			
N_2	295,771	13,881	43,031	338,802			
O_2	17,405	829	13,028	30,433			
CO_2	75,488	3,574		75,488			
CO	17	1		17			
NOx	159	5		159			
SO_2	1,034	43		1,034			
$Ca(OH)_2$							
Total	427,737	20,000	56,788	478,413	2,548	125	6,113
Temperature, °F	686	686	110	337	-	686	337
Pressure, psia.	14.6	15.4	16.1	14.7	14.7	14.7	14.7

TABLE 4-5A
LAKESIDE COAL FIRED UNIT
MASS AND ENERGY BALANCE
(FURNACE)

Basis: 60F & H2O(l)		Ca/S =		2.09	SO2 Capture = 45.0%	
			TEMP.F	LB/HR	BTU/LB	BTU/HR
INPUT:						
FEED			60			
9,970	IGT calc.					
10,077	HHV Act.					
Comp.	wt%					
C	55.75			17310		
H	3.88			1205		
O	7.34			2279		
N	1.09			338		
S	3.03			941		
Cl	0.00			0		
Ash	9.67			3003		
$H_2O(l)$	19.24			5974		
total	100.00					
Subtotal	312.89	MMBtu/hr		31050	0.0	0
NAT. GAS	23.6%	of energy				
21721	Btu/lb (HHV)		60	4450	0.0	0
	96.65	MMBtu/hr				
SORBENT	wt%		70			
$Ca(OH)_2$	96.2			4544		
Ash	3.8			179		
Total	100.0			4723	4.5	21254
AIR	wt%		70			
O_2	22.94			2606	2.1	5591
N_2	75.77			8606	2.4	20834
$H_2O(v)$	1.28			146	1064.0	155174
(MW =	28.797	)				
Subtotal	2495	scfm		11358		181600
AIR	wt%		473			
O_2	22.94			86857	93.1	8084002
N_2	75.77			286875	102.8	29491706
$H_2O(v)$	1.28			4861	1247.8	6065891
(MW =	28.797	)				
Subtotal	83154	scfm		378592		43641598
HEAT OF COMBUSTION						409055329
TOTAL				430173		452899782
OUTPUT:						
FLUE GAS	vol%		3257			
O_2	3.73		4.24%	17405	826.2	14379529
N_2	72.42			295771	917.7	271434470
$H_2O(v)$	12.08			31742	2888.0	91669700
CO_2	11.76			75488	908.7	68598277
SO_2,ppmv	1107			1034	617.9	638838
HCl,ppmv	0			0	588.4	0
NOx,ppmv	237		0.388	159	908.7	144229
CO,ppmv	41		lb/MMBtu	17	926.2	15328
Ash/C,S				6246	703.3	4392640
(MW =	28.916	)				
Subtotal	100.00			427860		451273011
RESIDUE			3257			
Carbon	1.12%			26		
S	1.53%			35		
Ash				2252		
Subtotal				2313	703.3	1626771
HEAT LOS	0.00%					0
TOTAL				430173		452899782
	Mass Closure	=		100.00%	Energy Closure =	100.00%

TABLE 4-5B
LAKESIDE COAL FIRED UNIT
MASS AND ENERGY BALANCE
(BOILER)

Basis: 60F & H2O(l) Boiler Exit Hopper Ash = 2.0% of total

		TEMP.F	LB/HR	BTU/LB	BTU/HR
INPUT:					
FLUE GAS	vol%	3257			
O2	3.73		17405	826.2	14379529
N2	72.42		295771	917.7	271434470
H2O(v)	12.08		31742	2888.0	91669700
CO2	11.76		75488	908.7	68598277
SO2,ppmv	1107		1034	617.9	638838
HCl,ppmv	0		0	861.1	0
NOx,ppmv	237		159	908.7	144229
CO,ppmv	41		17	926.2	15328
Ash w/Carbon			6246	703.3	4392640
(MW =	28.916)				
Subtotal	100.00		427860		451273011
BOILER FEEDWATER		422			
H2O(l)			337406	393.9	132917543
R. STEAM		0	0	0.0	0
TOTAL			765265		584190554
OUTPUT:					
FLUE GAS	vol%	686			
O2	3.73		17405	143.9	2504690
N2	72.42		295771	157.7	46647573
H2O(v)	12.08		31742	1350.8	42877196
CO2	11.76		75488	146.5	11059910
SO2,ppmv	1107		1034	105.3	108893
HCl,ppmv	0		0	131.6	0
NOx,ppmv	237		159	146.5	23254
CO,ppmv	41		17	161.0	2664
Ash w/Carbon			6121	137.7	842996
(MW =	28.916)				
Subtotal	100.00		427735		104067176
ECONOMIZER ASH		686	125	137.7	17204
STEAM @ 940psig		890			
H2O(v)			337406	1415.9	477746017
R. STEAM		0	0	0.0	0
BLOWDOWN @ 0.0%			0		0
HEAT LOSS	0.52%				2360158
TOTAL			765265		584190554

Mass Closure = 100.00% Energy Closure = 100.00%

TABLE 4-5C
LAKESIDE COAL FIRED UNIT
MASS AND ENERGY BALANCE
{AIR HEATER}

Basis: 60F & H2O(l) AIR LEAKAGE = 15.00%

		TEMP.F	LB/HR	BTU/LB	BTU/HR
INPUT:					
FLUE GAS	vol%	686			
O2	3.73		17405	143.9	2504690
N2	72.42		295771	157.7	46647573
H2O(v)	12.08		31742	1350.8	42877196
CO2	11.76		75488	146.5	11059910
SO2,ppmv	1107		1034	105.3	108893
HCl,ppmv	0		0	131.6	0
NOx,ppmv	237		159	146.5	23254
CO,ppmv	41		17	161.0	2664
Ash w/Carbon			6121	137.7	842996
(MW =	28.916)		------------------		------------------------
Subtotal	100.00		427735		104067176
AIR	wt%	110			
O2	22.94		99885	10.8	1078094
N2	75.77		329906	12.1	4006811
H2O(v)	1.28		5590	1081.6	6046259
(MW =	28.797)		------------------		------------------------
Subtotal			435381		11131164
			======		========
TOTAL			863116		115198340
OUTPUT:					
FLUE GAS	vol%	343			
O2	5.74		30433	62.9	1914637
N2	73.02		338802	69.9	23679741
H2O(v)	10.88		32471	1186.9	38539568
CO2	10.35		75488	62.0	4680226
SO2,ppmv	974		1034	44.9	46467
HCl,ppmv	0		0	57.2	0
NOx,ppmv	208		159	62.0	9840
CO,ppmv	36		17	72.3	1197
Ash w/Carbon			6121	62.3	381099
(MW =	28.881)		------------------		------------------------
Subtotal	100.00		484524		69252775
		473			
AIR	wt%	473			
O2	22.94		86857	93.1	8084002
N2	75.77		286875	102.8	29491706
H2O(v)	1.28		4861	1247.8	6065891
(MW =	28.797)		------------------		------------------------
Subtotal	83,154 scfm		378592		43641598
HEAT LOSS @ 2%					2303967
			======		========
TOTAL			863116		115198340

Mass Closure = 100.00% Energy Closure = 100.00%

TABLE 4-5D
LAKESIDE COAL FIRED UNIT
MASS AND ENERGY BALANCE
{ELECTROSTATIC PRECIPITATOR}

Basis: 60F & H_2O(l) ESP EFFICIENCY = 99.86 %

		TEMP.F	LB/HR	BTU/LB	BTU/HR
INPUT:					
FLUE GAS	vol%	343			
O_2	5.74		30433	62.9	1914637
N_2	73.02		338802	69.9	23679741
H_2O(v)	10.88		32471	1186.9	38539568
CO_2	10.35		75488	62.0	4680226
SO_2,ppmv	974		1034	44.9	46467
HCl,ppmv	0		0	57.2	0
NOx,ppmv	208		159	62.0	9840
CO,ppmv	36		17	72.3	1197
Ash w/Carbon			6121	62.3	381099
(MW =	28.881)		======		========
TOTAL	100.00		484524		69252775
OUTPUT:					
FLUE GAS	vol%	337			
O_2	5.74	6.44	30433	61.5	1872144
N_2	73.02	dry	338802	68.4	23160956
H_2O(v)	10.88		32471	1184.1	38447999
CO_2	10.35		75488	60.6	4573619
SO_2,ppmv	974		1034	43.9	45415
HCl,ppmv	0		0	56.0	0
NOx,ppmv	208		159	60.6	9616
CO,ppmv	36		17	70.8	1172
Ash w/Carbon		0.021	9	60.9	522
(MW =	28.881)	lb/MM Btu	----------		----------
Subtotal	100.00		478411		68111443
ESP SOLIDS		337			
Ash w/Carbon&Sulfur			6113	60.9	372372
			----------		----------
Subtotal			6113		372372
Heat Loss	2.00%				768960
			======		========
TOTAL			484524		69252775

Mass Closure = 100.00% Energy Closure = 100.00%

TABLE 4-6. LAKESIDE UNIT #7 OVERALL MASS AND ENERGY BALANCE w/GR-SI @ 30 MWe Net Power Out

Basis: 60°F & H2O as liquid

Input:	Lb/hr	Btu/hr
Furnace -		
Coal, incl. heat of combustion	31,050	312,890,850
Natural Gas, incl. heat of combustion	4,450	96,652,147
Burner Air	274,482	7,017,544
Overfire Air	104,110	2,661,730
Sorbent Air	11,358	181,600
Sorbent	4,723	21,254
Air Leakage	56,789	1,451,891
Total	**486,962**	**420,877,016**

Output:	Lb/hr	Btu/hr
Furnace -		
Bottom Ash, incl. heat of combustion	2,313	1,992,522
Boiler -		
Energy to Steam Cycle		344,828,474
Boiler Exit Ash, incl. heat of	125	19,646
ESP -		
Fly Ash, incl. heat of combustion	6,113	491,847
Stack -		
Flue Gas	478,411	68,111,443
System Heat Loss		5,433,084
Total	**486,962**	**420,877,016**

reducing valve, flow meter, flow control valve, safety shut-off valve, and vent valves. The natural gas is reduced in pressure from 15 psig (103 kPa) to an injection pressure of 2 to 4 psig (14 to 28 kPa). The design gas flow was 1978 scfm (0.9334 m^3/s), with equal flow of 198 scfm (0.0933 m^3/s) through each nozzle. A piping and instrument diagram of the GR system is shown in Figure 4-12.

Natural gas is fed to ten injection nozzles on the boiler rear and side walls. Six of the injectors mix FGR to enhance jet penetration and mixing and four inject natural gas only. During operation, only the reburning injectors with FGR were required to achieve proper penetration and dispersion across the furnace plane. The design natural gas input accounts for 23.6% of the total heat input. The maximum design and normal conditions for natural gas injection operation is shown below:

	Normal	Design (max.)
Natural Gas Flow (lb/hr)	4,381	9,386
Natural Gas Flow (scfm)	1,572	3,352
Natural Gas Btu Input (10^6 Btu/hr)	94.4	204
FGR Flow (lb/hr)	19,900	23,900
FGR Flow (scfm)	4,500	5,400
Natural Gas Pressure (psig)	2	3.8
FGR Pressure (in.W.C.)	19	23

The FGR used with GR corresponds to 3 to 5% of the total boiler exit flow. Flue gas was extracted from the breeching between the boiler exit and the air heater gas inlet. This location was selected since it is upstream of the air heater, where air leakage increases the O_2 concentration. The FGR system incorporates a high static booster fan and a multiclone dust collector. Flue gas was directed through a multiclone dust collector which removes particulate matter to prevent wear of the booster fan. The dust loading was reduced from approximately 11 gr/dscf (25 g/m^3) to 2 gr/dscf (5 g/m^3). The flue gas was then directed to a high static fan which increased the static pressure from approximately +1" W.C. (0.25 kPa) to +20" W.C. (5.0 kPa) normal.

Flue gas was then routed to a venturi for flow measurement, then to the six nozzles where dampers regulated the flow to each injector. The FGR fan was equipped with tight shut-off dampers to prevent gas leakage to the boiler exit when the GR-SI system was not in use.

OFA air was injected through six ports on the rear wall of the furnace. OFA is extracted from two secondary air ducts which have sufficiently high static pressure, therefore the system did not require an OFA booster fan. The flow of OFA through each port was controlled by flow dampers. The nozzles protruded beyond the tubewall into the furnace. This feature helped keep slag from building up and interfering with reburning fuel flow. The nozzles were water cooled, requiring 25 gpm (1.6 l/s) water flow, to prevent overheating and to further reduce slag deposition. Nozzle penetrations required bent tube sections. The nozzle wallboxes were designed to permit nozzle cleaning with the unit on line, through use of aspirating air. This was necessary for personnel protection since the unit is a positive draft design.

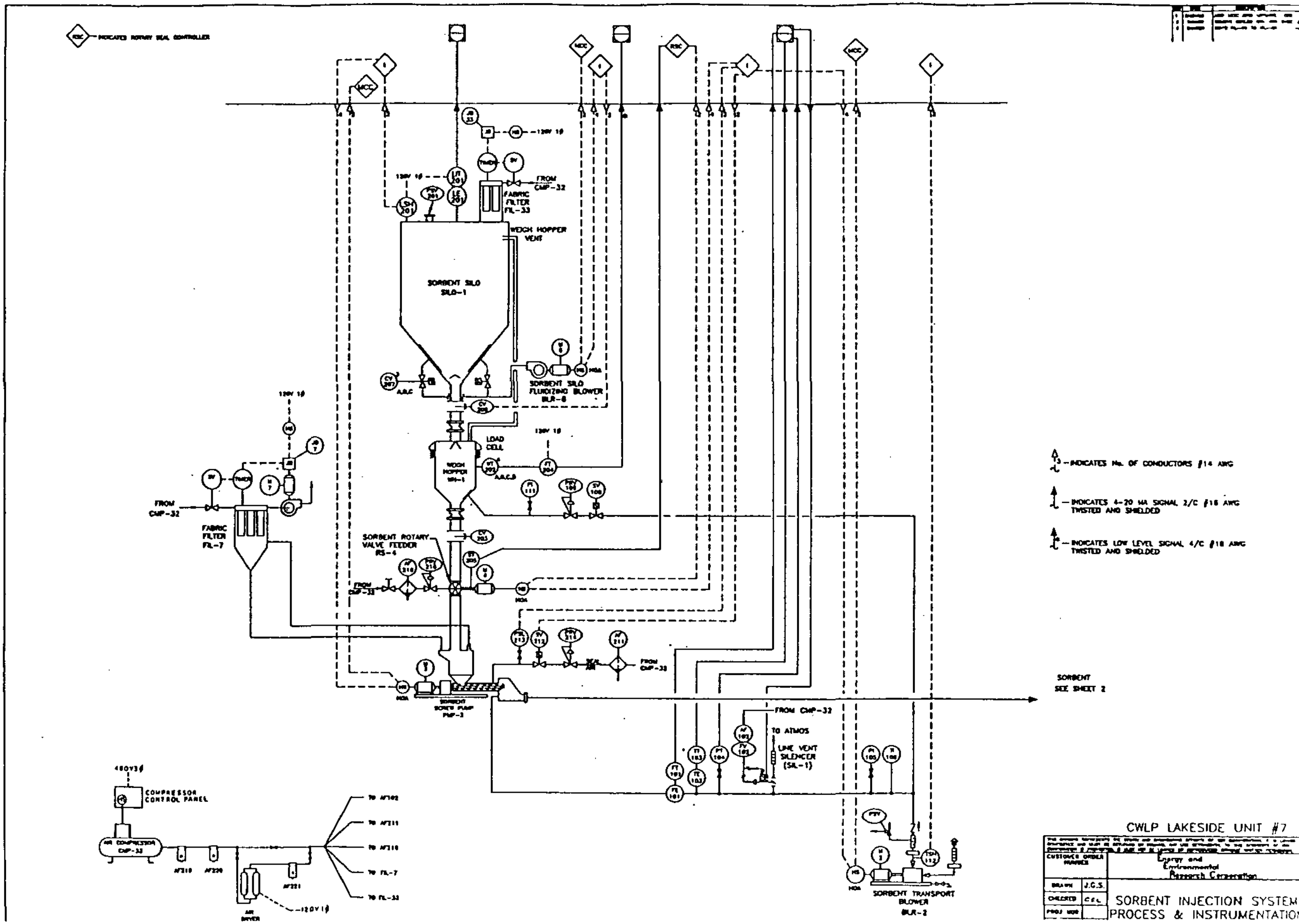
OFA was obtained from the two secondary air ducts which carry 500°F (260°C) combustion air. Since the unit is a positive draft design, the secondary air is relatively high in pressure, at 45" W.C. (11 kPa); therefore, a booster fan was not required. OFA was ducted to six ports on the rear wall of the furnace. Butterfly dampers controlled the air flow to each port. The dampers were not tightly shut off, allowing cooling air to flow to the nozzles when the reburning system was not in operation.

4.2.3 SI System

The SI system was designed to store, meter, and convey micron-sized sorbent to nozzles on the front and side walls of the upper furnace. The baseline sorbent used throughout this program was Linwood hydrated lime, which was on average 93% $Ca(OH)_2$. It has a mass mean diameter under 3 microns and a bulk density of approximately 30 lb/ft^3 (480 kg/m^3). The SI system was sized to inject sorbent at a rate corresponding to a Ca/S molar ratio of 2.0. The single sorbent/transport air stream is divided into ten equal streams, which are then carried to ten injectors on the front and side walls of the upper furnace. Two sizes of injectors, placed at two elevations, were used to completely cover the furnace flow field. Additional air, denoted as SI air to enhance sorbent jet penetration and mixing, is provided by a high static fan. Piping and instrument diagrams of the SI system are shown in Figures 4-13 and 4-14.

The SI system was comprised of the following major components: sorbent storage silo, weigh hopper, rotary valve feeder, screw pump, air transport blower, conveying line, sorbent splitter, SI air fan, and injection nozzles. The function of each of these is described below. A sorbent storage silo was erected near the boiler house. It holds nominally 3 days supply of sorbent. Pre-pulverized sorbent was carried to the site in tanker trucks. The trucks were unloaded with truck mounted blowers; the transport line was equipped with an industry standard quick connect coupling. The sorbent was transported to the top/center of the silo using conveying air and discharged into a target box. The conveying air was discharged through a filtered vent. The filter vent cartridges were cleaned using reverse air pulse jets. Cleaning air to these filters was provided by a small air compressor, equipped with a regenerative air dryer. To enhance sorbent discharge through the conical bottom of the silo, six fluidizing air slides were installed. Upon discharge from the silo, sorbent flowed through an automatic slide gate valve, then to a weigh hopper. The conical bottom of the weigh hopper was also equipped with four fluidizing air slides. The weigh hopper was mounted on four load cells, which are microcell strain gauges, to monitor the quantity of sorbent flow through the rate of weight loss. A rate of weight loss transmitter was used to convey the weight loss signal to the sorbent feed control system.

From the weigh hopper the sorbent flowed through a manually controlled slide gate valve to a rotary valve feeder. The operation of this variable speed feeder determined the rate of sorbent flow to the boiler. The variable speed rotary valve feeder operated


INDICATES ROTARY SEAL CONTROLLER
SORBENT SILO SILO-1
WEIGH HOPPER VENT
FABRIC FILTER FIL-33
FROM CMP-32
SORBENT SILO FLUIDIZING BLOWER BLR-8
LOAD CELL
WEIGH HOPPER WH-1
SORBENT ROTARY VALVE FEEDER RS-4
FABRIC FILTER FIL-7
FROM CMP-32
SORBENT SCREW PUMP PMP-3
SORBENT SEE SHEET 2
FROM CMP-32
TO ATMOS
LINE VENT SILENCER (SIL-1)
SORBENT TRANSPORT BLOWER BLR-2
COMPRESSOR CONTROL PANEL
AIR COMPRESSOR CMP-32
AIR DRYER
TO AF102
TO AF211
TO AF310
TO FIL-7
TO FIL-33
INDICATES No. OF CONDUCTORS #14 AWG
INDICATES 4-20 MA SIGNAL 2/C #18 AWG TWISTED AND SHIELDED
INDICATES LOW LEVEL SIGNAL 4/C #18 AWG TWISTED AND SHIELDED
CWLP LAKESIDE UNIT #7
Energy and Environmental Research Corporation
DRAWN J.C.S.
CHECKED C.E.L.
SORBENT INJECTION SYSTEM
PROCESS & INSTRUMENTATION

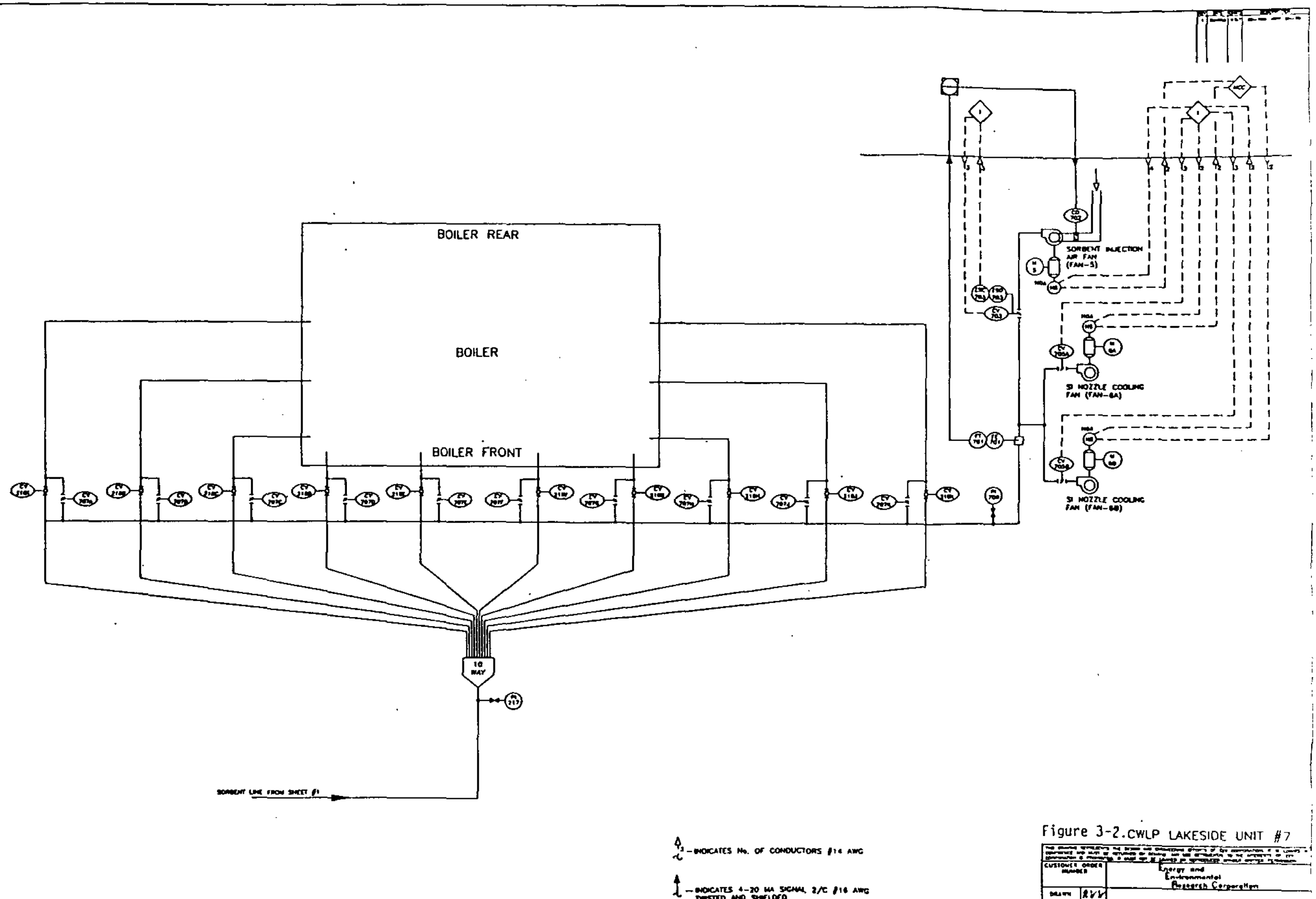


Figure 4-14. Lakeside Unit #7 Sorbent Injection piping and instrument diagram (sheet 2 of 2)

at 8 to 25 revolutions per minute, delivering sorbent at a rate of 2,450 to 7,800 lb/hr (0.309 to 0.984 kg/s). Directly below the weigh hopper was the sorbent screw pump, which is used to discharge the sorbent into the transport line. It has an 8" (20 cm) screw, which continuously delivers a "plug" of sorbent into its windbox. This solid "plug" prevented leakage of air back into the sorbent delivery system.

Sorbent transport air was supplied by a positive displacement blower, which has a constant output of 798 scfm (0.377 m^3/s) at a pressure of 12 psig (83 kPa). The conveying air was injected through nozzles in the screw pump windbox, where it entrained sorbent and carried it into the transport line. The transport line was a 5" (13 cm) I.D. 1/8" (3.2 mm) rubber-lined hose. It was designed to transport 150°F (66°C) gas. The transport line carried the sorbent/transport air to the sorbent splitter, which divides a single sorbent stream into ten equal streams for injection at the nozzles.

Ten 1 1/2" (3.8 cm) diameter conveying lines were then used to carry sorbent/transport air to the furnace. A more substantial air stream, provided by a high static radial type fan with capacity of 28,560 lb/hr (3.60 kg/s) at 70" W.C. (17 kPa), was mixed with the sorbent/transport air stream at the injection nozzles. Double concentric injectors are used with sorbent/transport air introduced into the center and the more substantial injection air introduced into the outer passage of the nozzle. These streams mix in the barrel of the nozzle before injection into the boiler. The portion of the injection nozzles extending into the furnace was stainless steel. The SI system also had redundant air cooling fans to cool nozzles when the system is not in use.

4.2.4 Fly Ash/Sorbent Waste Handling

The major waste product of GR-SI, a mixture of coal ash and spent and unreacted sorbent, is collected in a newly erected ash silo for later off-site disposal. This material is similar to high calcium ash that results from firing western coal. It exhibits pozzolanic reactivity; i.e., it has cementitious properties when mixed with water. If it is handled with a wet sluicing system discharging to an ash pond, it can build up as scale on the hydrovactor and the conveying pipe, thereby rendering such a system inoperable. Various waste handling alternatives were considered and dry handling and off-site disposal were chosen. The unit had two methods of handling fly ash, the new dry ash handling system and the previously used wet sluicing system. A local control switch allowed selection of either system by the operator.

The fly ash/sorbent mixture was collected from ESP bottom hoppers, the boiler outlet hopper and the multiclone. The material was then pneumatically conveyed to the top of the ash silo using air drawn through air intakes upstream of the ash hoppers. At the top of the ash silo, the ash and conveying air were separated with an air separator/filter. The solid material fell then into the ash silo. The silo was equipped with two discharge systems, one for completely dry loading of pneumatic tankers using a telescopic chute, and the other a conventional dustless unloader with water addition. These systems were incorporated to permit sale of dry ash for use as a fill material, or for normal loading of trucks for transport to a landfill. The ash silo was also equipped with fluidizing air slides to facilitate ash discharge. The design incorporated air heaters to prevent caking of the solid material.

4.2.5 Sootblowing System Modifications

The boiler is equipped with wallblowers in the radiant furnace and retractable sootblowers in the convective pass. There are eight wallblowers (type IR) in the furnace, which are used on an as-needed basis to control slag deposits, and seven sootblowers (type IK) in the convective pass, which come into service to maintain superheat steam temperature near the design point. These sootblowers utilize saturated steam from the main drum with the pressure reduced.

The condition of these blowers was suspect at the initiation of the project; therefore, all of the sootblowers were replaced at project expense. It was expected that the wallblowers would continue to see limited use, but that the sootblowers in the convective pass would be used more frequently (an expected increase from 2 hours per day to 6 hours per day).

4.2.6 Auxiliary Power

The GR-SI system power consumption as well as changes in power usage by other plant equipment (e.g., ID and FD fans, pumps, ESP, etc.) were monitored in the field test. Power for the nozzle cooling fans was supplied by the plant grid. The GR operation requires 350 kWe while the SI operation requires 362 kWe, for a total of 712 kWe or approximately 2% of full load power output.

4.2.7 Equipment List

Gas Reburning

Valve Train Equipment:

1 - 6" Shut-off valve, mfr. Rockwell

1 - 3" Pressure reducing valve, C.I. const., mfr. Fisher, Tag No. G-PRV-302

1 - 6" Pressure relief valve, C.I./S.S. trim const., mfr. Fisher, Tag No. G-PSV-304

1 - 8" Gas flowmeter, mfr. Rockwell, Tag No. G-FE-306, G-FT-306

2 - 8" Gas safety shut-off valves, mfr. DeZurik, Tag Nos. G-SSV-307, G-SSV-309

1 - 2" Gas vent valve, mfr. ASCO, Tag No. G-SV-310

1 - 6" Gas flow control valve, mfr. Fisher, Tag No. G-CV-311

10 - Gas nozzles, mfr. EER, (details proprietary)

Flue Gas Recirculation:

1 - Multiclone, mfr. Western Precipitator, Size 3x3, Tag No. G-Mcn-1

1 - FGR fan, design - 100 hp, Tag No. G-Fan-1

Overfire Air:

6 - Overfire air ports (air cooled), mfr. EER (details proprietary)

2 - Flow control dampers w/ Beck electric drives, Tag Nos. G-CV-405A, G-CV-405B

Sorbent Injection

1 - Storage silo, 26' dia. x 40' w/60°conical hopper, Tag No. G-Silo-1

1 - Weigh hopper, 5' dia. x 8'9" w/60° conical hopper, Tag No. G-WH-1

1 - Dust collector, 600 sq. ft. bag area, reverse jet, mfr. Dynamic Air, Tag No. G-Fil-17

1 - 8" Sorbent screw pump, 25 hp, 0-931 cf/hr, mfr. Fuller, Tag No. G-Pmp-3

1 - Sorbent transport blower, 60 hp, 798 scfm @12 psig, mfr. Spencer, Tag No. G-Blr-2

10 - Coaxial jet sorbent injectors, C.S./S.S., designed by EER (details proprietary)

1 - Sorbent injection air fan, 125 hp, 5,650 scfm @ 35" W.C. diff. press., mfr. Robinson, Tag No. G-Fan-5

2 - Sorbent injection cooling fans, 5 hp, mfr. Clarage, Tag Nos. G-Fan-6A8, G-Fan-6B

1 - Sorbent equipment air compressor, 40 hp, 186 scfm @ 100 psig, mfr. Gardner Denver, Tag No. G-Cmp-32

1 - Air dryer, 240 scfm compressed air @ 100 psig, mfr. Hankison, Tag No. G-AD-1

1 - Ash handling system, U.C. Service Corporation

5.0 CAPITAL COST

The capital cost for the GR-SI system installed on Hennepin Unit #1 is shown in Table 5-1. The SI system costs shown include flue gas humidification, which was a necessity for the Hennepin application to maintain ESP performance. The capital costs for the GR-SI system installed on Lakeside Unit #7 are shown in Table 5-2. It should be noted that these capital costs reflect the added project management and engineering required for a retro-fit technology demonstration. Capital costs for future conventional commercial installations will be less than the costs shown. The startup costs are included in the engineering, project management and construction costs. For the Hennepin system the startup costs were approximately $460,000, and for the Lakeside system approximately $310,000. Project management costs were equally split between the two systems, since the work was completed in a single project.

The costs per kWe for the two different systems at the two sites shows the economy of scale for the larger Hennepin unit compared to the Lakeside unit. The GR-SI system for the Hennepin (71 MWe net) unit, more than twice the size of the Lakeside Unit (30 MWe net) and also including flue gas humidification, was approximately one-half the

TABLE 5-1. HENNEPIN UNIT #1, 71 MWe (net) GR-SI SYSTEM CAPITAL COSTS

Category:	GR System	SI System*
Engineering	$431,350	$406,450
Equipment/Materials	$553,150	$778,400
Construction	$3,018,950	$3,377,700
Project Management	$379,950	$379,950
Total	$4,383,400	$4,942,500
Cost/kWe @71 MWe net	$62	$70

* Includes flue gas humidification system

cost of the Lakeside unit based on a $/kWe assessment. The Hennepin unit capital cost was $132/kWe compared to $257/kWe for the Lakeside unit.

TABLE 5-2. LAKESIDE UNIT #7, 30 MWe (net) GR-SI SYSTEM CAPITAL COSTS

Category:	GR System	SI System
Engineering	$431,700	$378,600
Equipment/Materials	$533,750	$616,300
Construction	$2,570,800	$2,676,150
Project Management	$257,050	$257,050
Total	$3,793,300	$3,928,100
Cost $/kWe (30 MWe net)	$126	$131

6.0 ESTIMATED OPERATING COST

Variable and fixed operating costs were estimated for both the Hennepin and Lakeside units for the GR-SI combination system, GR only and SI only. These costs are shown in Tables 6-1 through 6-6 and are expressed as annual incremental costs. The variable costs for both systems are based on a 65% capacity factor, full output for 65% of the time (5694 hours at full capacity) over a one year period. All of the operating costs shown are based on annual rates and costs; to obtain the variable operating costs and rates per hour, divide the annual costs and rates by 5,694.

The operating costs reflect the slight loss in boiler efficiency as a result of GR. The added fuel required to make up for the efficiency loss was done in accord with the ratio of the primary coal fuel to the natural gas reburning fuel used during GR. Maintenance costs for the GR system were estimated at 2% of the total installed costs, 2.5% for the GR-SI combination and 3% for the SI system. The fixed costs do not include any capital charges.

For the GR-SI cases shown in Tables 6-1 through 6-6, the operating costs are also shown as costs per ton of NOx plus SOx removed. For the GR cases, the costs per ton of NOx removed are shown and for the SI cases the costs per ton of SOx removed are shown.

The total incremental net operating costs for the combined GR-SI systems on Hennepin Unit #1 and Lakeside Unit #7 were $418 and $412 per ton of NOx and SOx removed, respectively. The incremental net operating costs for the GR systems on Hennepin Unit #1 and Lakeside Unit #7 were $1,054 and $1,355 per ton of NOx removed, respectively. The incremental net operating costs for the SI systems on Hennepin Unit #1 and Lakeside Unit #7 were $400 and $332 per ton of SOx removed, respectively. The lower cost per ton for the Lakeside unit is due to the higher Ca/S ratio used and thus higher SO_2 removal, 45% versus 35% for the Hennepin unit.

TABLE 6-1.

GR-SI w/Humidification SYSTEM

Illinois Power Hennepin Unit #1

71 MWe Tangentially-fired Boiler

Capital Cost

Total Installed Cost (TIC)	**$9,325,900**

Annual Incremental Operating Costs

(Based on a 65% Capacity Factor)

	Annual Use	Cost/Unit	Cost/ Yr	(NOx + SOx) $/ton Removed
Variable Costs:				
Raw Materials:				
Coal	46,492 MM Btu	$1.24 /MM Btu	$57,649	$9
Natural Gas (18%)	760,658 MM Btu	$1.28 /MM Btu	$973,642	$159
Hydrated Lime	17,330 tons	$83 /ton	$1,442,177	$235
Utilities:				
Electricity	4,555,200 kWhr	$0.04 /kWhr	$182,208	$30
Water	8,541 Mgal	$0.60 /Mgal	$5,125	$1
Ash Disposal:	13,677 tons	$9.29 /ton**	$127,061	$21
Sub-Total			$2,787,862	$454
Fixed Costs:				
Labor*:				
Maintenance @ 60% of 2.5% of TIC			$139,889	$23
Supervision @ 20% of O & M labor			$27,978	$5
Supplies:				
Maintenance @ 40% of 2.5% of TIC			$93,259	$15
Admin. and Gen. Ovhd. (60% of total labor):			$100,720	$16
Sub-Total			$361,845	$59
Total Gross Operating Cost			**$3,149,707**	**$513**
*SO2 Allowance Credit @ $95/ton****			*($481,566)*	*($95)*
Total Net Operating Cost			**$2,668,141**	**$418**

* No extra operators required.
** Cost based on DOE guideline
*** February 1996

TABLE 6-2.
GR SYSTEM
Illinois Power Hennepin Unit #1
71 MWe Tangentially-fired Boiler

Capital Cost

Total Installed Cost (TIC)	**$4,383,400**

Annual Incremental Operating Costs

(Based on a 65% Capacity Factor)

	Annual Use	Cost/Unit	Cost/ Yr	(NOx) $/ton Removed
Variable Costs:				
Raw Materials:				
Coal	46,492 MM Btu	$1.24 /MM Btu	$57,649	$54
Natural Gas (18%)	760,658 MM Btu	$1.28 /MM Btu	$973,642	$914
Utilities:				
Electricity	2,239,213 kWhr	$0.04 /kWhr	$89,569	$84
Ash Disposal (reduction):	(3,462) tons	$9.29 /ton**	($32,159)	($30)
Sub-Total			$1,088,701	$1,022
Fixed Costs:				
Labor*:				
Maintenance @ 60% of 2% of TIC			$52,601	$49
Supervision @ 20% of O & M labor			$10,520	$10
Supplies:				
Maintenance @ 40% of 2% of TIC			$35,067	$33
Admin. and Gen. Ovhd. (60% of total labor):			$37,873	$36
Sub-Total			$136,061	$128
Total Gross Operating Cost			**$1,224,762**	**$1,149**
*SO2 Allowance Credit @ $95/ton****			*($189,363)*	*($95)*
Total Net Operating Cost			**$1,035,399**	**$1,054**

* No extra operators required.
** Cost based on DOE guideline
*** February 1996

TABLE 6-3.
SI w/Humidification SYSTEM
Illinois Power Hennepin Unit #1
71 MWe Tangentially-fired Boiler

Capital Cost

Total Installed Cost (TIC) **$4,942,500**

Annual Incremental Operating Costs

(Based on a 65% Capacity Factor)

	Annual Use	Cost/Unit	Cost/ Yr	(SOx) $/ton Removed
Variable Costs:				
Raw Materials:				
Hydrated Lime	17,330 tons	$83 /ton	$1,442,177	$376
Utilities:				
Electricity	2,315,987 kWhr	$0.04 /kWhr	$92,639	$24
Water	8,541 Mgal	$0.60 /Mgal	$5,125	$1
Ash Disposal:	13,677 tons	$9.29 /ton**	$127,061	$33
Sub-Total			$1,667,002	$435
Fixed Costs:				
Labor*:				
Maintenance @ 60% of 3% of TIC			$88,965	$23
Supervision @ 20% of O & M labor			$17,793	$5
Supplies:				
Maintenance @ 40% of 3% of TIC			$59,310	$15
Admin. and Gen. Ovhd. (60% of total labor):			$64,055	$17
Sub-Total			$230,123	$60
Total Gross Operating Cost			**$1,897,125**	**$495**
*SO2 Allowance Credit @ $95/ton****			*($363,998)*	*($95)*
Total Net Operating Cost			**$1,533,127**	**$400**

* No extra operators required.
** Cost based on DOE guideline
*** February 1996

TABLE 6-4.
GR-SI SYSTEM
CWLP Lakeside Unit #7
30 MWe Cyclone-fired Boiler

Capital Cost

Total Installed Cost (TIC)	**$7,721,400**

Annual Incremental Operating Costs

(Based on a 65% Capacity Factor)

	Annual Use	Cost/Unit	Cost/ Yr	(NOx + SOx) $/ton Removed
Variable Costs:				
Raw Materials:				
Coal	29,501 MM Btu	$1.14 /MM Btu	$33,631	$7
Natural Gas (23.6%)	461,912 MM Btu	$1.86 /MM Btu	$859,156	$168
Hydrated Lime	13,446 tons	$83 /ton	$1,119,008	$219
Utilities:				
Electricity	4,054,128 kWhr	$0.04 /kWhr	$162,165	$32
Ash Disposal:	12,911 tons	$9.29 /ton**	$119,942	$23
Sub-Total			$2,293,902	$448
Fixed Costs:				
Labor*:				
Maintenance @ 60% of 2.5% of TIC			$115,821	$23
Supervision @ 20% of O & M labor			$23,164	$5
Supplies:				
Maintenance @ 40% of 2.5% of TIC			$77,214	$15
Admin. and Gen. Ovhd. (60% of total labor):			$83,391	$16
Sub-Total			$299,590	$59
Total Gross Operating Cost			**$2,593,492**	$507
*SO2 Allowance Credit @ $95/ton****			*$307,702*	*$95*
Total Net Operating Cost			**$2,285,790**	**$412**

* No extra operators required.
** Cost based on DOE guideline
*** February 1996

TABLE 6-5.

GR SYSTEM
CWLP Lakeside Unit #7
30 MWe Cyclone-fired Boiler

Capital Cost

Total Installed Cost (TIC)	**$3,793,300**

Annual Incremental Operating Costs

(Based on a 65% Capacity Factor)

	Annual Use	Cost/Unit	Cost/ Yr	(NOx) $/ton Removed
Variable Costs:				
Raw Materials:				
Coal	29,501 MM Btu	$1.14 /MM Btu	$33,631	$46
Natural Gas (23.6%)	461,912 MM Btu	$1.86 /MM Btu	$859,156	$1,164
Utilities:				
Electricity	1,992,900 kWhr	$0.04 /kWhr	$79,716	$108
Ash Disposal (reduction):	(2,144) tons	$9.29 /ton**	($19,918)	($27)
Sub-Total			$952,585	$1,290
Fixed Costs:				
Labor*:				
Maintenance @ 60% of 2% of TIC			$45,520	$62
Supervision @ 20% of O & M labor			$9,104	$12
Supplies:				
Maintenance @ 40% of 2% of TIC			$30,346	$41
Admin. and Gen. Ovhd. (60% of total labor):			$32,774	$44
Sub-Total			$117,744	$160
Total Gross Operating Cost			$1,070,329	$1,450
*SO2 Allowance Credit @ $95/ton****			*($170,830)*	*($95)*
Total Net Operating Cost			**$899,498**	**$1,355**

* No extra operators required.
** Cost based on DOE guideline
*** February 1996

TABLE 6-6.
SI SYSTEM
CWLP Lakeside Unit #7
30 MWe Cyclone-fired Boiler

Capital Cost

Total Installed Cost (TIC)	**$3,928,100**

Annual Incremental Operating Costs

(Based on a 65% Capacity Factor)

	Annual Use	Cost/Unit	Cost/ Yr	(SOx) $/ton Removed
Variable Costs:				
Raw Materials:				
Hydrated Lime	13,446 tons	$83 /ton	$1,119,008	$326
Utilities:				
Electricity	1,047,984 kWhr	$0.04 /kWhr	$41,919	$12
Ash Disposal:	12,911 tons	$9.29 /ton**	$119,942	$35
Sub-Total			$1,280,869	$374
Fixed Costs:				
Labor*:				
Maintenance @ 60% of 3% of TIC			$70,706	$21
Supervision @ 20% of O & M labor			$14,141	$4
Supplies:				
Maintenance @ 40% of 3% of TIC			$47,137	$14
Admin. and Gen. Ovhd. (60% of total labor):			$50,908	$15
Sub-Total			$182,892	$53
Total Gross Operating Cost			$1,463,761	$427
*SO2 Allowance Credit @ $95/ton****			*($325,736)*	*($95)*
Total Net Operating Cost			$1,789,497	$332

* No extra operators required.
** Cost based on DOE guideline
*** February 1996

7.0 COMMERCIAL APPLICATIONS

This is an era in the history of the U.S. where the increase in electric power generating capacity has been very minimal, and those power plants that have been built are relatively low capacity. Therefore, the GR-SI technology when applied, in most cases will be retro-fitted to existing power plants. The cost of retro-fit technologies can vary significantly from one site to another depending on the available space for a retro-fit and the operating characteristics of the power plant.

7.1 Gas Reburning

In the case of the GR technology one critical cost item concerns the availability of natural gas. If natural gas is available at the site to supply a sufficient rate, the capital cost for this site would be much less compared to a plant that did not have gas on-site. The capital cost differential would be primarily related to the pipeline distance required to bring gas on-site. Another factor that affects the capital cost is the existing combustion air windbox pressure. If there is adequate windbox pressure, 4-6 in. W.C. or greater, then a booster OFA fan would not be required. The air pressure required is also dependent on the size of the unit, the larger the size the higher the air pressure required for the OFA system.

GR is most effective where furnace temperatures are hot (2600+ and the hotter the better) and residence times under the reducing conditions created in the reburning zones are long enough to effectively reduce NOx emissions. The longer the reburning zone residence time, the greater the NOx reduction will be.

The biggest economic factor of whether or not GR is selected as a means for reducing NOx emissions on a specific power plant is the cost differential between the reburning fuel, natural gas, and the primary fuel, coal. The smaller the cost differential, the more attractive the GR system will become.

7.2 Sorbent Injection

The in-furnace SI technology is fairly effective for moderate reductions (30% to 45%) of SO_2 emissions from power plants and could well be used at power plants firing low-to-medium sulfur content coals to bring a plant into air emissions compliance. The technology can be applied to all types of boilers and the retrofit requirements and operating costs are fairly minimal. The cost of lime is by far the greatest operating cost, accounting for some 75% of the incremental operating costs (when capital charges are not included). The downside of the SI system relates to the increased sootblowing requirements, the production of a highly alkaline ash, the increased grain loading to downstream particulate removal devices, and reduced ESP performance.

The technology could best be applied to a power plant that use a bag house rather than an ESP for particulate removal. A bag house is a constant removal device, so when the inlet flue gas grain loading is increased, the particulate in the stack gas does not increase. An ESP is a constant efficiency device so if inlet grain loading doubles, as a general rule, the outlet grain loading will also double. A power plant that has an ESP with a high specific collection area would best be suited for a SI retro-fit. With SI, the resistivity of the fly ash will increase due to the reaction of the sorbent with sulfur trioxide, a gas that reduces fly ash resistivity. Regarding ESP performance, the best fly ash for removal is that which has a resistivity in the range of 108 to 1011 ohm-cm. Fly ash that has a resistivity outside this range is not removed as well in an ESP.

The alkalinity of the fly ash removed from the flue gas, as a result of SI, must be reduced before disposal to a conventional landfill or the ash must be sent to a special lined landfill at a higher disposal cost.

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Part B

Project Performance and Economics

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1.0 INTRODUCTION

1.1 Purpose of the Project Performance and Economics Report

Since the DOE public design reporting requirement was promulgated during the project demonstration testing, two reports have been combined, Part A - The "Public Design Report" and Part B - the "Project Performance and Economics Report". There is an overlap in the two report formats because they were intended to be completed at different times. Since the two reports were completed in the same time frame, overlaps exist. Where such overlap does exist, a brief description is presented and reference is made to Part A for a more detailed discussion on the specific subject.

Part B - "Project Performance and Economics Report" of this report is a designated deliverable under the U.S. Department of Energy Agreement No. DE-FC22-87PC79796, Attachment C (Federal Assistance Reporting Checklist). This project performance and economics report summarizes the operational and environmental test results for the project, provides technology economic analyses, and describes the commercialization potential and plans for commercial implementation of the technology.

1.2 Overview of the Project

As a part of the U.S. Department of Energy's Clean Coal Technology Program (Round 1), a project was completed to demonstrate control of boiler emissions that comprise acid rain precursors, specifically oxides of nitrogen (NO_x) and sulfur dioxide (SO_2). The project involved demonstrations of the combined use of GR-SI on coal-fired utility boilers to assess the air emissions reduction potential of these technologies. See Part A - §1.2 for an expanded overview of the project.

1.2.1 Background and History of the Project

The technologies demonstrated under this project were GR for nitrogen oxide emissions control and SI for sulfur dioxide emissions control. See Part A §2.0 for a brief overview of the GR and SI processes and their history regarding development of these technologies.

1.2.2 Project Organization

EER was responsible for conducting this project as directed and funded by the three funding participants: the U.S. Department of Energy (DOE), the Gas Research Institute (GRI) and the State of Illinois Department of Commerce and Community Affairs (DCCA). For more details concerning the project organization, see Part A - §1.5.1 and §1.5.2.

1.2.3 Project Description

The clean coal technologies demonstrated under this CCT-1 project were GR for nitrogen oxides control and SI for sulfur dioxide control. GR involves the injection of natural gas above existing coal-fired burners to create a reducing or reburning zone for destruction of NO_x, followed by the injection of OFA above the reburning zone to complete combustion of the reducing (fuel) gases formed in the reburning zone. SI involves the introduction of a fine grind alkali sorbent (e.g., calcium hydroxide) into the furnace that reacts with the sulfur dioxide to form alkali sulfites and sulfates which are removed in the downstream electrostatic precipitator. To achieve the program objectives for the demonstration of the GR-SI technologies, the project was conducted in the following three phases:

- Phase I Design and Permitting
- Phase II Construction and Startup

- Phase III Operation, Data Collection, Reporting, and Disposition

For a more detailed description of the project, see Part A - §1.2.

1.2.4 Project Sites

The first demonstration was performed at Illinois Power's (IP) Hennepin Unit #1, located in Hennepin, Illinois. This unit is a 71 MWe (net) tangentially-fired boiler that fires high-sulfur Illinois coal. The second demonstration was performed at City Water Light & Power's (CWLP) Lakeside Unit #7, located in Springfield, Illinois. This unit is a 33 MWe (gross) cyclone-fired boiler that also fires high-sulfur Illinois coal. The third demonstration was proposed for Central Illinois Light Company's (CILCO) Edwards Unit #1, located in Bartonville, Illinois. This unit is a 117 MWe (net) wall-fired unit. It was eliminated from consideration after completing the engineering assessment due to the excessive capital cost requirement to upgrade the existing electrostatic precipitator so that SI could be tested.

1.2.5 Project Schedule

The overall project schedule is shown in Part A - § 1.2.10, Figure 1-3. After contract award, following finalization of the U.S. Department of Energy - EER Agreement, the project was initiated on July 1, 1987. The project was completed on June 30, 1996.

1.3 Objectives of the Project

The primary objective of the project was to demonstrate the long term viability of the GR-SI technology on different boiler types and to evaluate the technology for its potential for reducing NO_x and SO_2 emissions, the major acid rain precursors from these boilers. Another objective was the development of GR-SI systems that were easy to operate and relatively maintenance free.

The specific performance goals of the these demonstration projects on coal-fired utility boilers were to demonstrate NO_x and SO_2 emission reductions of 60% and 50%, respectively. The focus of the program was to demonstrate the application of combined GR and SI technologies to meet stringent emission regulations when firing medium-to-high sulfur coals. The overall goal of the project was to meet these emission reduction levels, and do so with acceptable unit operability and minimal operating cost. For more details on project objectives, see Part A - §1.2.9 and §1.3.

1.4 Significance of the Project

Coal-fired power plants have been cited as the major source of acid rain precursors (NO_x and SO_2) and there is considerable pressure within the United States and from Canada to reduce the emissions of these acid rain precursors. For more details concerning the significance of the project see Part A - §1.4.

1.5 DOE's Role in the Project

The U.S. Department of Energy (DOE) provided both funding and project/technical review. The DOE provided management review of the GR-SI system designs, construction plans, environmental monitoring plans, and test results. The DOE was responsible for monitoring all aspects of the project. For more details concerning the DOE involvement see Part A - §1.5.

2.0 TECHNOLOGY DESCRIPTION

2.1 Description of the GR-SI Technology

GR-SI is an application of two processes which may be applied separately or together for NO_x and/or SO_2 control. With GR, natural gas is injected into the utility boiler furnace above the conventional fuel (coal for these demonstrations) burners (primary zone) to form a slightly sub-stoichiometric air ratio reducing region called the reburning zone. For a detailed description of the GR-SI technologies see Part A - §2.1.

2.2 Proprietary Information

The detail and control information on the GR and SI technologies concerning GR, OFA and SI injection locations, orientations, and velocities, and furnace residence times between zones, are considered proprietary to the Energy and Environmental Research Corporation.

Reburning NO_x reduction performance depends on a range of different process parameters, which include the following: initial NO_x level, temperature at the reburning and burnout zones, reburning zone stoichiometric ratio, stoichiometric ratio in the main combustion and burnout zones, residence times in the reburning and OFA zones, and mixing rates of the reburning fuel and OFA.

Data gathered during EER's various reburning demonstration programs have been reported in graphical format, where measured NO_x reduction performance has been compared with most of the above variable parameters, and where reasonably good correlations with individual parameters can be seen. However, given the rather complex inter-relationship between the various controlling parameters and reburning system performance, EER has elected not to present statistical correlations of the data.

EER believes that the use of such correlations can be misleading, particularly with respect to extrapolating system performance to other boilers and boundary conditions. To successfully correlate the data requires more complex process models, such as those used by EER during the development of designs for each of the different boiler applications.

These process/design models have been validated during the course of the demonstration project, and have been shown to accurately reflect performance trends as a function of the various process parameters for boilers of very different designs. For business reasons, and because of their importance in developing commercial guarantees, EER prefers not to make public any details of the process models.

2.3 Hennepin Unit #1

The host site is located in Hennepin, Illinois; the Hennepin Station is owned and operated by the Illinois Power Company. Hennepin Station Unit #1 was used for the GR-SI demonstration; it is a 71 MWe (net) CE tangentially coal-fired unit. For more information concerning Hennepin Unit #1, see Part A - §2.2.

2.3.1 Hennepin GR Process Description

The GR process at Hennepin included the integration of three systems: (1) natural gas injection, (2) FGR and (3) OFA injection. In the GR process, natural gas is mixed with FGR at the gas injection nozzles which are located above the primary combustion zone. The FGR provides for momentum to assist in the dispersion and mixing of the natural gas with the hot furnace flue gases to create a reducing zone to facilitate reduction of NO to N_2. Above this reducing zone, higher up in the furnace, OFA is added to complete the combustion of the fuel gases produced in the reducing zone. For more information on the GR process used at Hennepin, see Part A - §2.2.3.

2.3.2 Hennepin SI Process Description

The SI system was designed to store, meter, and convey micronized sorbent to nozzles located on the corners of the upper furnace. The baseline sorbent used throughout this program was Linwood hydrated lime, which on average contained 93 wt% $Ca(OH)_2$. Sorbent was conveyed with transport/injection air to the nozzles. Two sizes of injectors, placed at two elevations, were used to completely cover the furnace flow field. The SI system was comprised of the following major components: a sorbent storage silo, weigh hopper, rotary valve feeder, screw pump, air transport blower, conveying line, sorbent splitter, SI air fan, and injection nozzles. For more information on the SI process used at Hennepin, see Part A - §2.2.4

2.3.3 Hennepin Humidification Process Description

The humidification system was designed to cool the flue gases exiting the boiler air heater to within 70°F of the flue gas dew point. The system was designed to operate over a range of boiler load from 12 MWe to 71 MWe (full load). With the SI process, the $SO_3^=$ in the flue gas, a normal combustion by-product that conditions the fly ash to reduce its resistivity, is removed by the sorbent. The purpose of the humidification system is make up for the loss of $SO_3^=$. Cooling and increasing the water content of the flue gas both reduce fly ash resistivity. Humidification therefore is used to restore the particulate removal performance of the ESP. For more information on the humidification system used at Hennepin, see Part A - §2.2.5

2.3.4 Hennepin GR-SI Simplified Process Flow Diagram

A process flow diagram for the GR-SI system is shown in Figure 4-3, Part A - §4.1. The natural gas reburning injectors were installed above the existing tangentially-fired coal burners. OFA was added above the injectors but prior to SI. Reburning control was integrated into the existing boiler control system. The SI system included a storage silo, weigh hopper and transport system to deliver sorbent into the furnace at a point above OFA injection but prior to the furnace exit. Because of the increased fly ash resistivity that results when using SI, a flue gas humidification system was installed to decrease resistivity to restore the ESP performance. The flue gas humidification system was installed in the inlet ductwork to the existing ESP.

2.3.5 Hennepin GR-SI Stream Data

The overall mass and energy balance for Hennepin Unit #1 when applying the GR-SI technology is shown in Table 4-3, Part A - §4.1.1. The process streams flowing into and out of the process blocks are designated by stream numbers in Figure 4-2, Part A- §4.1.1, and the mass flow rates for these streams are shown in Table 4-1, Part A - §4.1.1.

2.3.6 Piping and Instrumentation Diagrams

Piping and instrument diagrams of the Hennepin GR-SI system are shown in Figures 4-4 through 4-9, Part A - §4.1.2 thru 4.1.4. The GR system, including FGR and OFA, is shown in Figures 4-4 and 4-5. The SI system piping and instrumentation diagrams are shown in Figures 4-6 and 4-7, and the humidification system piping and instrumentation diagrams are shown in Figures 4-8 and 4-9.

2.4 Lakeside Unit #7

This host site is located in Springfield, Illinois. Unit #7 at the Lakeside Station was used for the GR-SI demonstration. This unit began its initial operation in 1953 and was supplied by Babcock & Wilcox (B&W). The Lakeside Station is owned and operated by the Springfield City Department of Water, Light and Power (CWLP). The host unit is a 33 MWe (gross) cyclone coal-fired unit. It is normally operated only five months per year: April, June through August and October. The GR-SI testing was designed to conform to this operating schedule. For more details on the Lakeside unit #7, see Part A - §2.3.

2.4.1 Lakeside GR Process Description

The GR (reburning zone) injection system was designed to convey, meter and inject natural gas through nozzles into the region above the primary combustion zone. Like the Hennepin system, FGR was added with the gas to provide for good dispersion and mixing in the furnace.

The Lakeside Station had no gas firing capability prior to this project; therefore, a high pressure header to the boiler house with a metering and pressure reducing station was installed. A tie-in line was then made to carry the natural gas from this station to the reburning fuel flow/pressure regulation and metering system. The natural gas train, common to all injection nozzles, incorporates a pressure reducing valve, flow meter, flow control valve, safety shut-off valve, and vent valves. Above the reburning zone, OFA was injected to complete the combustion of the fuel gases produced in the reburning zone. For more details on the Lakeside GR process see Part A - §2.3.3.

2.4.2 Lakeside SI Process Description

The SI system was designed to store, meter, and convey micronized sorbent to nozzles on the front and side walls of the upper furnace. The baseline sorbent used throughout this program was Linwood hydrated lime, which on average contained 93 wt% $Ca(OH)_2$. Sorbent was conveyed with transport/injection air to the nozzles. The SI system was comprised of the following major components: a sorbent storage silo, weigh hopper, rotary valve feeder, screw pump, air transport blower, conveying line, sorbent splitter, SI air fan, and injection nozzles. For more details on the Lakeside SI process see Part A - §2.3.4.

2.4.3 Lakeside GR-SI Simplified Process Flow Diagram

The Lakeside GR-SI process flow diagram is shown in Figure 4-12, Part A - §4.2. The GR injectors were installed above the existing cyclones, with OFA being added above the injectors but prior to SI. GR control was integrated into the existing boiler control system. The SI system included a storage silo, weigh hopper and transport system to deliver sorbent into the furnace at a point above the OFA injection point but prior to the furnace exit. For more details concerning the process flow diagram and stream flows see Part A - §4.2.

2.4.4 Lakeside GR-SI Stream Data

The overall mass and energy balance for Lakeside Unit #1 when applying the GR-SI technology is shown in Table 4-6, Part A - §4.2.1. The process streams flowing into and out of the process blocks are designated by stream numbers in Figure 4-12, Part A- §4.2.1, and the mass flow rates for these streams are shown in Table 4-4, Part A - §4.2.1.

2.4.5 Piping and Instrumentation Diagrams

Piping and instrument diagrams of the Lakeside GR-SI system are shown in Figures 4-12 through 4-14, Part A - §4.2.2. The GR system, including FGR and OFA, is shown in Figure 4-12. The SI system piping and instrumentation diagrams are shown in Figures 4-13 and 4-14.

3.0 UPDATE OF THE PUBLIC DESIGN REPORT

The report guidelines, to which this report is to conform, were issued by the U.S. DOE after demonstration testing was initiated. The Public Design Report (Part A) and the Project Performance and Economics Report (Part B) were both completed at the conclusion of demonstration testing; therefore, no update is required for the Public Design Report.

4.0 DEMONSTRATION PROGRAMS

The GR-SI test plans for both the Hennepin and Lakeside demonstration programs were prepared at the initiation of the projects and were revised and improved before the initiation of the GR-SI optimization testing. The test plans specified the purpose, number of tests, operating conditions, and measurements to be taken during each test. The testing was divided into several test series designed to optimize the GR–SI system operation with respect to NO_x and SO_2 reduction and unit performance. The variables assessed relative to their impact on the performance of the GR-SI technologies are presented in Table 4-1.

TABLE 4-1. GR-SI PRIMARY VARIABLES AND THEIR FUNCTIONS

Variable	Major Function	Other Effects
Nat. Gas/Coal Heat Input	NO_x Reduction	SO_2, Particulate Reductions
Sorbent/Coal (Ca/S Ratio)	SO_2 Reduction	Fouling, ESP Performance
Sootblowing Cycle	Fouling Reduction	Tube Erosion
Humidification (Hennepin)	ESP Performance	Fouling, Corrosion
Primary Zone Excess Air	Less Reburning Fuel	Slagging, Increased LOI
FGR Rate	Nat. Gas Dispersion	Furnace Temperatures
OFA	Fuel Burnout	Steam Attemperation, Boiler and ESP Efficiencies
Sorbent Transport Air	Sorbent Dispersion	Similar as for OFA

4.1 Hennepin GR-SI Demonstration

Unit #1 at the Hennepin Station was used for the GR-SI demonstration. Unit #1 is a tangentially coal-fired unit.

4.1.1 Test Plans

The GR-SI test plan was prepared initially in Phase I of the project and was revised in Phase III, just before the initiation of the GR–SI optimization testing. The test plan specified the purpose, number of tests, operating conditions, and measurements to be taken during each test. The testing was divided into several test series designed to optimize the GR–SI system operation with respect to NO_x and SO_2 reduction and unit performance.

The goals of the test program were to initially assess the impacts of process parameters on NO_x and SO_2 reduction and unit operation, then to operate the unit over an extended period (one year) under optimum conditions. To determine the impacts of process parameters, short parametric tests were planned. Tests were organized into test series in which single parameters were evaluated incrementally.

Short term tests were carried out to determine optimum GR performance with respect to boiler load, coal zone stoichiometric ratio, reburning zone stoichiometric ratio, gas heat input, recycled flue gas, OFA, burner and reburning fuel injector tilt, and the mills in service. To determine the optimum NO_x reduction with respect to these parameters, the parameters were varied using the GR-SI process design as a guide. The SI process was evaluated by determining the optimum operating conditions resulting in a minimum of 50% SO_2 reduction. The parameters evaluated include sorbent flow rate (or Ca/S molar ratio), sorbent jet velocity, and sorbent configuration (i.e. sorbent nozzles in use). The impacts of boiler load on the SO_2 removal process and required changes in sootblowing were also determined.

These tests led to establishment of the optimum process variables for the long-term testing. The long-term testing was designed to demonstrate the effectiveness of the GR-SI process over an extended period for control of NO_x and SO_2 emissions. An extensive set of measurements was taken to determine GR-SI impacts on the operation of the unit including unit steam generation/thermal performance, fouling/slagging, tubewall wastage rates, species in-furnace concentration/emissions, ESP performance, and ash/spent sorbent impacts. The measurements were designed to verify that GR-SI may be applied without adverse impacts on unit operability and durability. A further goal of the test program was to assess the economic impacts of GR-SI operation. This was desired to demonstrate the cost effectiveness of GR-SI technology for commercial application.

Testing was divided into five major test programs:

- Short Term GR Optimization (Parametric) Tests
- Short Term SI Optimization (Parametric) Tests
- Short Term GR-SI Optimization (Parametric) Tests
- Short Term Gas/Coal Cofiring and Gas/GR
- Long Term GR-SI Tests

4.1.1.1 Short-term Tests

Short term optimization tests were completed for GR, SI and GR-SI operation at Hennepin. Also a short test program was completed using gas/coal co-firing and gas/GR (100% gas).

4.1.1.1.1 GR Optimization Tests

GR process parameters, such as primary zone stoichiometric ratio, reburning zone stoichiometric ratio, natural gas and FGR quantities, coal burner tilt, injector tilt, and OFA flow rate, were varied over wide ranges. It was found from these tests that primary and reburning zone stoichiometric ratios, natural gas input, and FGR flow rate had strong impacts on NO_x emissions. Variation of the OFA flow rate during GR operation was found to have some effect on NO_x emissions although the impacts were not strongly established. Burner tilting was determined to have slight impact on NO_x emissions while natural gas injector tilting had resulted in an insignificant effect on NO_x reduction.

The GR optimization test series was designed based upon the results obtained from these start–up tests. The main objectives of this test series were to: (1) consolidate the impacts of the aforementioned GR parameters on NO_x reductions; (2) obtain a data base for evaluating the impacts of GR-SI on the boiler performance and operability; and (3) confirm and strengthen the GR design methodology. The GR optimization tests evaluated the impacts on a full range of GR process parameters over a wide range of boiler loads. The following process variables were evaluated:

- Primary Zone Stoichiometric Ratio (SR_1)
- Reburning Zone Stoichiometric Ratio (SR_2)
- Burnout (Exit) Zone Stoichiometric Ratio (SR_3)

Other parameters evaluated were:

- Boiler load
- Number of mills in service
- Burner tilt
- FGR flow rate

- Reburning fuel injector tilt

The evaluation of these parameters is presented in Section 5.1 Effects of Operating Variables on Results under Section 5.0 Technical Performance. The test conditions for the test series are summarized in Table 4-2. The initial test conditions at full load concentrated on evaluating the sole impacts of staged combustion on NO_x emissions, N_2O emissions, and flame zone characteristics. During these tests, combustion air of up to 20% of total was gradually biased to the OFA ports by appropriate adjustments of the OFA damper positions and burner windbox dampers. In effect, the primary zone stoichiometric ratio was allowed to decrease until the flame appearance became unacceptable to the boiler operators. These tests allowed the operating range of the primary zone stoichiometric ratio to be established. The results were used to set an operating limit for the primary zone stoichiometric ratio during GR tests. In addition to the standard measurements (CEMS, coal and ash sampling, control room data, etc), N_2O measurements were made at the maximum staged combustion condition. Time integrated ash samples were collected during these test conditions for analysis of carbon content. Gas temperature along with concentrations of CO and O_2 in the reburning zone of the furnace were measured under the baseline condition. Impacts of burner tilting on NO_x emissions during baseline and GR operations were also evaluated at full load. During these tests, the firing angle of the burners was varied from their normal downward position to the maximum upward position. Although the tests called for a maximum upward tilt of 20 degrees, the actual firing position for the test was limited by steam temperatures and sootblowing requirements.

Since the operating conditions approximated the conditions used for the process design, detailed measurements consisting of the standard measurements as well as in-furnace (temperature, CO, O_2, etc.), N_2O, and carbon-in-ash were performed during this test. Adequate mixing of the reburning fuel with the primary combustion products had been found to have strong impact on the NO_x reduction effectiveness. The effect of the degree of mixing was evaluated by varying the injector velocity through the

TABLE 4–2. GAS REBURNING PARAMETRIC TEST CONDITIONS

TEST ID	TEST DESCRIPTION	LOAD (MW)	MILLS IN-SERVICE	BURNER TILT (DEG.)	PRIMARY SR	REBURN SR	BURNOUT SR	NG %	FGR (SCFM)	OFA (SCFM)	MEASUREMENTS STANDARD	IN-FURNACE (REBURNING ZONE)	N2O	C IN ASH
GR-33a	Baseline	70	3	-20	(#)	(#)	1.2	0	Cooling	Cooling	X	X	X	X
GR-33b	Staged Combustion	70	3	-20	(#)	(#)	1.2	0	Cooling	5000	X			
GR-33c	Staged Combustion	70	3	-20	(#)	(#)	1.2	0	Cooling	10000	X	X		X
GR-33d	Staged Combustion	70	3	-20	(#)	(#)	1.2	0	Cooling	15000	X			
GR-33e	Staged Combustion	70	3	-20	(#)	(#)	1.2	0	Cooling	Max.	X	X		X
GR-33f	*Low Excess Air*	70	3	-20	(#)	(#)	1.2	0	Cooling	As Req'	X			
GR-33g	Minimum Excess Air	70	3	-20	(#)	(#)	1.2	0	Cooling	As Req'	X			
GR-34a	Burner Tilt On Baseline NOx Emissions	70	3	Horizontal	(#)	(#)	1.2	0	Cooling	Cooling	X	X		X
GR-34b		70	3	20	(#)	(#)	1.2	0	Cooling	Cooling	X			
GR-35a	Burner Tilt On NOx Emissions During GR	70	3	-20	1.1	(#)	1.2	20 (*)	7000	As Req'	X	X	X	X
GR-35b		70	3	Horizontal	1.1	(#)	1.2	20 (*)	7000	As Req'	X			
GR-35c		70	3	20	1.1	(#)	1.2	20 (*)	7000	As Req'	X			
GR-36a	FGR Flow Variation	70	3	-20	1.1	(#)	1.2	20 (*)	3500	As Req'	X			
GR-36b		70	3	-20	1.1	(#)	1.2	20 (*)	Max	As Req'	X			
GR-37a	Reburning Zone SR Variation	70	3	-20	1.1	(#)	1.2	20 (*)	Max	As Req'	X	X	X	X
GR-37b		70	3	-20	1.1	(#)	1.2	15 (*)	Max	As Req'	X	X	X	X
GR-37c		70	3	-20	1.1	(#)	1.2	10 (*)	Max	As Req'	X	X	X	X
GR-38a	Load Variation	60	3	Normal	(#)	(#)	1.2	0	Cooling	Cooling	X	X		X
GR-38b		50	3	Normal	(#)	(#)	1.2	0	Cooling	Cooling	X	X		X
GR-38c		40-45	2	Normal	(#)	(#)	1.2	0	Cooling	Cooling	X	X		X
GR-39a	Mid Load Reburning Tests	60	3	Normal	(#)	(#)	1.25	0	Cooling	Cooling	X	X		X
GR-39b		60	3	Normal	1.1	(#)	1.25	10	7000	As Req'	X	X		X
GR-39c		60	3	Normal	1.1	(#)	1.25	20 (*)	7000	As Req'	X	X	X	X
GR-40a	Low Load Reburning Tests	40-45	2	Normal	(#)	(#)	1.3	0	Cooling	Cooling	X	X		X
GR-40b		40-45	2	Normal	1.1	(#)	1.3	10	7000	As Req'	X	X		X
GR-40c		40-45	2	Normal	1.1	(#)	1.3	20 (*)	7000	As Req'	X	X	X	X

(*) Or maximum gas available
(#) Calculated by the Boiler Performance Monitoring System -- Results in Table A-4

TABLE 4-2. GAS REBURNING PARAMETRIC TEST CONDITIONS (CONTINUED)

TEST ID	TEST DESCRIPTION	LOAD (MW)	MILLS IN-SERVICE	BURNER TILT (DEG.)	PRIMARY SR	REBURN SR	BURNOUT SR	NG %	FGR (SCFM)	OFA (SCFM)	MEASUREMENTS			
											STANDARD	IN-FURNACE (REBURNING ZONE)	N2O	C IN ASH
GR-41a	SR2 Variation	70	3	-20	1.08	(#)	1.2	10	7000	As Req'	X			
GR-41b		70	3	-20	1.08	(#)	1.2	15	7000	As Req'	X			
GR-41c		70	3	-20	1.08	(#)	1.2	18	7000	As Req'	X			
GR-42a	Staged Combustion	40	2	27	(#)	(#)	1.25	0	Cooling	5000	X			
GR-42b		40	2	27	(#)	(#)	1.25	0	Cooling	10000	X			
GR-42c		40	2	27	(#)	(#)	1.25	0	Cooling	15000	X			

(#) Calculated by the Boiler Performance Monitoring System -- Results in Table A-4 variation of the FGR flow rates. During these tests, total hydrocarbons at the economizer inlet were measured in addition to standard measurements. The impacts of the reburning zone stoichiometric ratio as well as mixing of the reburning fuel with primary zone combustion products were also investigated.

The reburning zone stoichiometric ratio was varied by injecting different amounts of natural gas into the reburning zone while keeping the primary zone stoichiometric ratio constant at 1.10. These tests allowed evaluation of NO_x control as a function of the quantity of natural gas injected.

Impacts of boiler load on NO_x emissions during baseline operation were also evaluated. The boiler was operated at 60, 70 and 80% of full load and at the same excess air levels as for full load. These tests set the baseline NO_x emissions at reduced boiler loads. Time integrated ash samples were collected from the flue gas during these tests for the analyses of carbon content in the ash. Limited GR tests were conducted at reduced boiler loads to investigate GR performance versus load variation. In these tests, different amounts of natural gas were injected and boiler emissions and performance were monitored under varied reburning zone conditions.

4.1.1.1.2 SI Optimization Tests

SI tests were performed without GR. During the tests, appropriate conditions and procedures for SI and humidification systems were established while parametric SI tests were conducted. The tests were used to evaluate the impacts of the following key variables on SO_2 emissions:

- Boiler load
- Calcium-to-sulfur molar ratio (Ca/S)
- Injection velocity
- Sorbent reactivity

SI test conditions are summarized in Table 4-3. The impacts of the boiler load on SO_2 emissions were evaluated in test series SI-1. At 100% boiler load, conditions were expected to be optimal for SI through the upper furnace injection nozzles. As boiler load was reduced, furnace gas temperatures at the upper nozzles were expected to fall; therefore, SI was switched to the lower nozzles.

Test Series SI-2 was designed to evaluate the impact of calcium-to-sulfur molar ratio at full load. Sorbent flow rates corresponding to Ca/S molar ratios up to 2.5 at full load were varied to evaluate the impacts of sorbent loading on SO_2 removal.

Finally, test series SI-3 tested the impact of injection velocity. Impacts of mixing on SO_2 removal were investigated through variation of injector velocity. During these tests, injection air flow was varied to obtain velocities corresponding to 150 and 350 ft/sec (46 to 107 m/s). These tests allowed the range of injection velocities to be evaluated before the GR-SI optimization tests.

4.1.1.1.3 GR-SI Optimization Tests

The optimum conditions for GR-SI were expected to be different from those without SI because of the effects of back radiation and furnace wall deposit changes under SI may have on temperature in the reburning zone. Therefore, another series was conducted to simultaneously optimize the GR-SI processes.

Table 4-4 summarizes the GR-SI optimization test conditions. The objective of the GR-SI test series was to optimize the process operating parameters with respect to boiler operability, and cost effectiveness of the process. The optimum conditions would then be used for the long-term test series, which were carried out immediately after the completion of this optimization test series. The optimum GR conditions, determined from the GR optimization tests, were set and the SI parameters were optimized at high load.

TABLE 4-3. SORBENT INJECTION PARAMETRIC TEST CONDITIONS

TEST ID	TEST DESCRIPTION	LOAD (MW)	MILLS IN-SERVICE	BURNER TILT (DEG.)	EXIT SR	Ca/S MOLAR	INJECTION ELEVATION	SORBENT FLOW (LB/HR)	TRANSPORT AIR FLOW (ACFM)	INJECTION AIR FLOW (SCFM)	INJECTION VELOCITY (FT/S)	MEASUREMENTS: STANDARD	MEASUREMENTS: UPPER-FURNACE	MEASUREMENTS: ESP	MEASUREMENTS: HUMIDIFICATION
SI-1a	Baseline	70	3	Normal	1.2	0.0	None	0	0	0	0	X	X	X	X
SI-1b	Load Variation	70	3	Normal	1.2	2.0	Upper	11000	546	4200	240	X	X		X
SI-1c		60	3	Normal	1.2	2.0	Upper	8800	539	3400	200	X			X
SI-1d		40-45	3	Normal	1.2	2.0	Lower	7000	533	2600	150	X			X
SI-2a	Ca/S Variation	70	3	Normal	1.2	1.0	Upper	5500	525	4200	240	X			X
SI-2b		70	3	Normal	1.2	1.5	Upper	8250	536	4200	240	X			X
SI-2c		70	3	Normal	1.2	2.5	Upper	maximum	552	4200	240	X			X
SI-3a	Injection Velocity Variation (Mixing)	70	3	Normal	1.2	2.0	Upper	11000	546	2600	150	X			X
SI-3b		70	3	Normal	1.2	2.0	Upper	11000	546	6100	350	X			X

TABLE 4-4. GR–SI OPTIMIZATION TEST CONDITIONS

Test ID	Test Description	Load (MW)	Primary SR	Reburn SR	Exit SR	NO (percent)	Ca/S Molar Ratio	Inj. Elev.	Inj. Vel. (FT/S)	Measurements: Standard	Measurements: ESP	Measurements: Sulfur Trioxide
GRSI–1a	Load Variation	45	1.1	0.9	1.25	18	2.00	Low	150	x	x	x
GRSI–1b		55	1.1	0.9	1.25	18	2.00	Low	150	x	x	x
GRSI–1c		60	1.1	0.9	1.18	18	2.00	Low	150	x		
GRSI–1d		60	1.1	0.9	1.18	18	2.00	High	150	x		
GRSI–1f		70	1.1	0.9	1.18	18	2.00	High	150	x		
GRSI–1g		60	1.1	0.9	1.18	18	2.00	High	150	x	x	
GRSI–1h		60	1.1	0.9	1.18	18	2.00	Low	150	x	x	
GRSI–1i		70	1.1	0.9	1.18	18	2.00	High	150	x	x	
GRSI–2a		70	1.1	0.9	1.18	18	2.00	High	150	x		
GRSI–3a	Inj. Velocity Variation	70	1.1	0.9	1.18	18	1.00	High	150	x	x	
GRSI–3b		70	1.1	0.9	1.18	18	1.00	High	200	x	x	
GRSI–3c		70	1.1	0.9	1.18	18	1.00	High	240	x	x	
GRSI–4	Velocity Trav. at SI inj. air	Dispatch	1.1	0.9	1.18	18	2.00	High	Max.	x		
GRSI–5	Velocity Trav. at SI inj. air	Dispatch	1.1	0.9	1.18	18	2.00	High	Max.	x		
GRSI–6a	GRSI Operation	45	1.1	0.9	1.18	18	2.00	High	240	x		
GRSI–6b		70	1.1	0.9	1.18	18	2.00	High	240	x		
GRSI–7a	Ca/S Variation	65	1.1	0.9	1.18	18	1.00	High	240	x		
GRSI–7b		65	1.1	0.9	1.18	18	1.50	High	240	x		
GRSI–7c		65	1.1	0.9	1.18	18	2.00	High	240	x		
GRSI–8a	Low Excess Air	65	1.05	0.9	1.15	18	1.75	High	240	x		
GRSI–8b		65	1.05	0.9	1.15	18	2.00	High	240	x		
GRSI–9a	Injection Elevation	50	1.1	0.9	1.18	18	1.75	High	240	x		x
GRSI–9b	Optimization	50	1.1	0.9	1.18	18	1.75	Low	240	x		
GRSI–9c		55	1.1	0.9	1.18	18	1.75	Low	240	x		x
GRSI–9d		55	1.1	0.9	1.18	18	1.75	High	240	x		
GRSI–10a	Ca/S Variation	70	1.1	0.9	1.18	18	1.00	High	240	x		
GRSI–10b		70	1.1	0.9	1.18	18	1.75	High	240	x		
GRSI–11a	Injection Configuration	70	1.1	0.9	1.18	18	1.75	High*	240	x		

* *Four front injectors only.*

During the 1991 fall outage, modifications to the humidification duct and reburning fuel injection nozzles were made. Post-outage testing ensured that the recommended GR–SI operating conditions would still satisfy the program objectives. Post–outage test conditions are summarized in Table 4-5. Post–outage testing at Hennepin was divided into two test series:

- Checkout Tests To ensure that the modified humidification system, ash handling system and the newly installed reburning fuel injectors were operational.

- Additional Parametric Tests To close the gap in the data base and to confirm some of the optimum operating parameters, which were to be evaluated during the long–term GR-SI demonstration.

4.1.1.1.4 Gas/Coal Cofiring and Gas/GR Short Term Tests

An evaluation of Gas/Coal Cofiring and Gas/GR was undertaken at Hennepin Unit 1, in September 1991. The purpose of this study was to evaluate these technologies, primarily for NO_x emissions control, in units affected by the 1990 Clean Air Act Amendments. Hennepin Unit 1 is equipped with corner burners each containing three coal nozzles as well as two levels of main gas burners and warm-up guns and two levels of gas ignitors. The gas burners can supply up to 100% of the full load heat input.

Short parametric tests, 58 - Gas/Coal Cofiring and 19 - Gas/GR tests, of 15 to 60 minute duration were conducted. Gas/Coal Cofiring was evaluated with natural gas heat input up to 42%, but the majority of tests were conducted with natural gas heat input of 34%. The cofiring results were compared to the 100% coal and 100% gas firing cases. Staged combustion with OFA was also evaluated for each condition. Other firing techniques evaluated in the Gas/Coal Cofiring test series include close-coupled GR and rich/lean firing, which were tested by trimming the burner dampers.

TABLE 4-5. POST–OUTAGE TEST CONDITIONS

Test ID	Test Description	Load (MW)	Mills In–Service	Primary SR	Reburn SR	Burnout SR	NO (percent)	FGR (scfm)	Overfire Air (scfm)	Measurements		
										Standard	ESP	Hydrogen Sulfide
GR–33a1	Baseline and SR1 Variation	70	3	1.14	1.14	1.15	0	Cooling	Cooling	x	x	x
GR–33a2		70	3	1.08	1.08	1.15	0	Cooling	As Req'	x		
GR–39a1		60	3	1.14	1.14	1.2	0	Cooling	As Req'	x	x	x
GR–39a2		60	3	1.08	1.08	1.2	0	Cooling	As Req'	x		
GR–42a1		45	2	1.14	1.14	1.25	0	Cooling	As Req'	x	x	x
GR–42a2		45	2	1.08	1.08	1.25	0	Cooling	As Req'	x		
GR–43a	FGR Variations	70	3	1.08	0.9	1.15	18	2000	As Req'	x		
GR–43c		70	3	1.08	0.9	1.15	18	4000	As Req'	x	x	
GR–44a		70	3	1.08	0.9	1.2	18	2000	As Req'	x		
GR–44b		70	3	1.08	0.9	1.2	18	3000	As Req'	x		x
GR–44c		70	3	1.08	0.9	1.2	18	4000	As Req'	x	x	
GR–45b		45	2	1.08	0.9	1.25	18	2000	As Req'	x		
GR–45c		45	2	1.08	0.9	1.25	18	2000	As Req'	x		x
GR–45d		45	2	1.08	0.9	1.25	18	4000	As Req'	x	x	
GR–45e		45	2	1.08	0.9	1.25	18	Max.	As Req'	x		
GR–46b		45	2	1.08	0.9	1.25	18	2000	As Req'	x		
GR–46c		45	2	1.08	0.9	1.25	18	3000	As Req'	x		x
GR–46d		45	2	1.08	0.9	1.25	18	4000	As Req'	x	x	
GR–46e		45	2	1.08	0.9	1.25	18	Max.	As Req'	x		
GR–50a	SR2 Variation	45	2	1.08	(#)	1.2	15	Max.	As Req'	x	x	
GR–50b		45	2	1.08	(#)	1.2	12	Max.	As Req'	x	x	
GR–50c		45	2	1.08	(#)	1.2	10	Max.	As Req'	x	x	
GR–51a1		70	3	1.08	(#)	1.2	15	Min.	As Req'	x		
GR–51a2		70	3	1.08	(#)	1.2	15	Max.	As Req'	x		
GR–51b		70	3	1.08	(#)	1.2	12	Max.	As Req'	x		
GR–51c		70	3	1.08	(#)	1.2	8	Max.	As Req'	x		

(#) Calculated by the *Boiler Performance Monitoring System* -- Results in Table A-4

TABLE 4-5. POST-OUTAGE TEST CONDITIONS (CONTINUED)

Test ID	Test Description	Load (MW)	Ca/S Molar Ratio	Primary SR	Reburn SR	Exit SR	NO (percent)	Injection Velocity (ft/s)	Injection Elevation	Measurements		
										Standard	ESP	
SI-5a	Ca/S Variation	70	1.5	1.15	1.15	1.2	0	250	High	x	x	
SI-5b		70	1.75	1.17	1.17	1.2	0	250	High	x	x	
SI-5c		70	2	1.17	1.17	1.2	0	250	High	x	x	
SI-6a	Ca/S Variation	45	1.5	1.1	1.1	1.25	0	250	High	x	x	
SI-6a2		45	1.5	1.1	1.1	1.25	0	250	High	x	x	
SI-6a3		45	1.5	1.1	1.1	1.25	0	250	High	x	x	
GRSI-12a	Ca/S Variation	70	1.5	1.08	0.9	Optimum	18	250	High	x		
GRSI-12b		70	1.75	1.08	0.9	Optimum	18	250	High	x	x	
GRSI-12c		70	2	1.08	0.9	Optimum	18	250	High	x		
GRSI-14a	SI Injection Velocity Variation: 6 Jets	70	1.75	1.08	0.9	Optimum	18	250	High	x		
GRSI-14b		70	1.75	1.08	0.9	Optimum	18	200	High	x	x	
GRSI-14c		70	1.75	1.08	0.9	Optimum	18	150	High	x		
GRSI-15a	SI Injection Velocity Variation	45	1.75	1.08	0.9	Optimum	18	150	High	x		
GRSI-15b		45	1.75	1.08	0.9	Optimum	18	200	High	x	x	
GRSI-15c		45	1.75	1.08	0.9	Optimum	18	250	High	x		
GRSI-19A	SR2 Variation	45	1.75	1.08	0.95	1.2	12	250	High	x	x	

Gas/GR performance was evaluated relative to the 100% gas firing case. The parameters evaluated include primary zone stoichiometric ratio, reburning zone stoichiometric ratio, reburning fuel injector tilt, primary burner tilt, and operating load. GR with up to 20% gas heat input was evaluated at various excess air levels. The primary purpose of the evaluation was to measure NO_x emissions control. The evaluation included the following parameters:

- Emissions (NO_x, SO_2, CO and CO_2)
- Thermal efficiency
- Ash carbon loss
- Steam temperatures
- Gas temperatures
- Load following capability
- Flame conditions

4.1.1.2 Long-term Tests

GR-SI demonstration tests provided an opportunity to assess the long-term impacts of the GR-SI process. Natural gas and sorbent were injected in each test period under optimum injection conditions identified during the GR-SI optimization tests. The unit was operated by plant personnel, under normal dispatch. Boiler performance and pollutant emissions were monitored continuously during the test period. Additional detailed measurements were performed to evaluate the impacts of:

- Boiler slagging and fouling
- Air heater fouling
- ESP performance
- Ash handling and disposal

The overall operability of the process was evaluated in addition to the above parameters. This includes injection system operation and reliability, deviations from normal boiler operation, maintenance requirements and process data.

Measurements conducted on a continuous, daily basis included:

- On line thermal performances and gas side pressure drop
- Flue gas composition including O_2, CO_2, CO, SO_2, NO_x, and total hydrocarbons
- Boiler operating parameters (flame characteristics, burner settings, etc.)
- ESP electrical operation (voltage, current)
- Sootblowing schedule
- Ash hopper evacuation schedule

Additional measurements conducted on a weekly or on an as needed basis provided assessment of the following parameters:

- Slagging and fouling rates
- Tube wastage
- N_2O emissions
- Flue gas stratification
- Fly ash resistivity at the ESP inlet
- Furnace gas temperatures and velocities
- Solid waste characteristics
- Coal, sorbent, ash, and water characteristics

4.1.2 Operating Procedures

In this section, operational procedures are described for start-up, normal operation, and shut-down, the pre-operational and post operational checklists, permissives, alarms and trips for the Hennepin GR-SI systems are shown in Appendix A. The control and monitoring of the GR/SI systems was accomplished through a Westinghouse Distributed Process Family (WDPF) control system. The WDPF system is capable of interfacing with other microprocessors. The WDPF sends and receives signals from various components in the GR/SI system.

During boiler operation without GR operation, the GR cooling air fan will be in service for the cooling of the FGR/natural gas injection nozzles and wall boxes and to protect these components from the high temperature furnace gases. Similarly, OFA air will cool the OFA nozzles, wall boxes, and duct work.

Each time, before the GR system was started up, a stable boiler load was established with normal Pulverized Coal (PC) firing, with two mills in operation, yielding a gross output load of approximately 36 MWe. The normal boiler combustion controls were placed in automatic operation with normal excess air prior to starting GR.

To start the GR system the operator opened the multiclone isolation damper and closed the FGR-injection fan inlet damper. The GR fan was then started. The fan turning gear automatically disengaged and the turning gear motor was de-energized automatically. The GR nozzle cooling fan automatically stopped and the outlet damper automatically closed. The FGR injection fan discharge damper then automatically opened and the seal air fan for the damper automatically stopped.

Using the WDPF the operator then opened the FGR injection fan control damper to establish the specified flue gas. The operator then increased the air to the coal burners to establish the specified excess O_2. With the WDPF, the operator slowly opened the OFA air control dampers to a specified value. During this step, the boiler air flow control remain in automatic control. This procedure kept the total boiler air flow at the same value but shifted some of the air away from the burners to the OFA air ports. During this period it was important to watch that adequate air flow was still maintained to the PC burners.

Following the air flow adjustment, natural gas was initiated to the furnace injections nozzles. To do this, all four natural gas nozzle manual valves were opened and also the main GR manual shutoff valve. Using the WDPF the automatic natural gas control valve was set at minimum flow. The combustion controls (air and feeder speeds) were kept in automatic and the GR gas flow was slowly increased using the WDPF. The feeder speed and total air flow start to back down to compensate for the increased heat input from the gas. At this time it was necessary to monitor the OFA air flow and adjust as necessary to keep the flow steady.

The flue gas O_2 was also monitored to be sure adequate excess air was being maintained at the furnace exit. The GR control and the FGR injection flow control were then switched to automatic control. Both OFA dampers were then switched to automatic control and the O2 level set for GR operation.

During on-line GR operation the operators were required to monitor furnace temperatures (requires 2400°F min.) via the WDPF. They were also required to monitor the PC burners. Two flame scanners out of four were required for GR operation. It was also necessary to monitor CO emissions (maximum is 1000 ppm) via the BPMS. Another critical item was the monitoring of the FGR blower fan bearings temperature via the WDPF.

When shutting down the GR system the operator increased the air flow to the PC burners to establish the specified excess O_2 and switched the natural gas automatic control valve to manual.

With the combustion controls (air and feeder speed) on automatic, GR flow was slowly reduced using the WDPF. The coal feeder speed and total air flow then start to increase to compensate for the decreased input from the natural gas. When the GR flow is at the specified minimum, the natural gas trip valves and GR manual valve were closed. OFA and gas flow were reduced at the same time.

With the WDPF the operator then slowly decreased the OFA control dampers to their minimum position. During this step the boiler air flow control remained in automatic control. The total air to the boiler remained at the same value but air flow was shifted away from the OFA ports to the burners. The total excess O_2 control point was then set for normal non GR operation. Note the control damper was typically operated in manual mode at minimum load.

The FGR injection fan control damper was then switched to manual and closed to its minimum setting. The outlet damper automatically closed, and the FGR seal air damper opened automatically. The operator verified this by way of the WDPF. The turning gear motor also started automatically and the operator should verified this also by WDPF.

The multiclone isolation damper was then closed and the FGR injection fan motor stopped. The GR nozzle cooling fan then automatically started and the GR cooling fan outlet damper (CV-607) automatically opened.

The following describes the start-up procedure used for the SI and humidification systems. The SI system could not be operated without the humidification system being on-line. First of all, one had to verify that there was an adequate quantity of sorbent in the sorbent silo and weigh hopper. Assuming the silo was full but the weigh hopper empty, the weigh hopper was filled by opening the weigh hopper sorbent inlet isolation valve. The sorbent silo air slide valves were then opened and the silo fluidizing air blower started. A low load or high load injection was then set. Low load filling will be described here. First of all the SI fan shut off damper to the low load nozzles were opened. The SI diverter valve was then positioned for the low load nozzles. The furnace SI air inlet control damper was set to 10% open and the SI injection fan was started.

Two of the three air compressors were then started and the air control valves adjusted to give the proper flow to the humidification dual fluid nozzles. The humidification water pump was then started and the water shutoff valves opened. A preset value of air/water differential pressure was then maintained and the water flow adjusted to maintain the desired inlet temperature to the ESP.

Once the humidification system was on-line, the sorbent screw pump (PMP-5) seal air valve was opened and the sorbent transport blower was started up. The transport air flow was then adjusted to obtain the desired air flow. The sorbent screw pump was started and then the sorbent rotary valve feeder was started. The weigh hopper air slide valve was opened and the sorbent fee rate was then monitored.

After start-up, the sorbent weigh hopper refill system was placed in the automatic refill mode. The weight of the sorbent in the hopper was determined from a weigh scale. Filling the hopper when very little sorbent remained was not desirable because the sudden impact of the falling sorbent could affect the sorbent feed rate. Therefore, the system was set initially to refill when 20% of the sorbent remains, filling stopped when the hopper was 80% full. When the system switched into automatic refill, the sorbent feed rate controller locked in on the last rate and maintained that rate throughout the refill process. No adjustment of the sorbent feed rate was possible during the refill procedure.

A fabric filter on the weigh hopper removed the fluidizing fill air that entered through the air slides and assisted the flow of material. A fabric filter exhaust fan located on top of the filter pulled air from both the filter and the transition hopper that was located between the filter and the sorbent screw-pump. The damper on the fabric filter exhaust fan was adjusted so that a slight vacuum was indicated by the flexible connection located under the rotary valve feeder. Removing all available air from the sorbent enabled the sorbent screw pump to more easily pump the sorbent. Maintaining a vacuum in the system also eliminated fugitive dust emissions and prevented any blow back through the rotary valve feeder.

Switching from high load to low load SI while the system was operating required the following procedure.

1. Stop sorbent rotary valve feeder.
2. Open the SI fan shut off damper to low load nozzles.
3. Close SI fan shut off damper to high load nozzles.
4. Start SI nozzle cooling fan.
5. Open sorbent nozzle cooling fan shut off damper.
6. Switch sorbent diverter valve from high to low load.
7. Start sorbent rotary valve feeder.

Switching from low load to high load SI while the system was operating required the following procedures.

1. Stop sorbent rotary valve feeder.
2. Stop SI nozzle cooling fan.
3. Close sorbent nozzle cooling fan shut off damper.
4. Open SI fan shut off damper to high load nozzles.
5. Close SI fan shut off damper to low load nozzles.
6. Switch sorbent diverter valve from low to high load.
7. Start sorbent rotary valve feeder.

The sorbent flow was turned off when the diverter valve was switched to eliminate any possibility of a small puff of sorbent escaping. This occurred because, for a short time the inlet opening on the moving slide gate was not centered over the valve sealing ring.

After startup the humidification system was placed in the automatic mode. The desired precipitator gas inlet temperature was set by the operator which automatically determined the required water flow rate. The normal operating range for the precipitator gas inlet temperature was 250-300°F. The water pressure for a given water flow rate was always lower than the air pressure to the dual fluid atomizing nozzles by a preset differential. That preset differential was automatically controlled.

Water strainers were cleaned when necessary as indicated by unequal flow rates and pressures among the three humidification lances in each duct. The duplex basket strainer was cleaned when a pressure differential of 5-7 psi across the strainer was reached. Air compressors were operated in their most efficient mode, depending on air demand. The compressors were placed in automatic start/stop or in the upper range modulation control mode. All compressors did not need to be operating in the same mode and/or at the same time.

The following describes the normal shutdown sequence for the SI and humidification systems.

1. Close weigh hopper air slide valve.
2. Stop sorbent rotary valve feeder.
3. Stop sorbent screw pump.
4. Stop sorbent transport blower
5. Close seal air valve.
6. Close SI fan inlet damper to the minimum setting.
7. Stop SI air fan.
8. Close SI air valves (verify limit switches are closed).
9. Start SI cooling fan.
10. Open SI nozzle cooling air shut-off valve.
11. Close humidification water shut-off valves.
12. Stop water pump.
13. Open air purge valves.
14. Stop atomizing air compressors.

The ash handling system differs from the other systems in that it was an existing operating system. IP operating personnel were familiar with the different parts of the ash sluice system and skilled in the day to day operation of the system. This section then addresses only the new components added as part of the GR-SI retrofit.

The ash conveyor to remove ash from the humidification system was designed to handle fine, dry, free-flowing ash. When the boiler was started up, the temperatures that existed in the boiler were raised gradually over a period of time, during which time water could accumulate in the hoppers of the fly ash system due to condensation. Collection of fly ash in the presence of this moisture caused the formation of lumps in the fly ash and prevent free flow. To prevent these conditions, before starting the boiler, the humidification system ash conveyor should be run continuously during the warm-up period of boiler operation. Once the boiler was in normal operation, the temperature of the flue gases were high enough to maintain the ash dry and free-flowing. The continuous conveyor operation removed fly ash as fast as it was deposited, which minimized water absorption by the fly ash and sorbent. When the temperatures were stabilized and only dry fly ash was being collected, the system was run in the normal operation mode.

Also, during the warm-up period, frequent and periodic checks should be made of the intakes to determine if fly ash is unloading properly. Compressed air supply must be available and properly adjusted. All operating units should be lubricated and checked for free operation, and all hoppers and intakes should be cleaned of debris, and crusted or caked ash.

The ash was removed periodically by an automatic control system. At the completion of the each conveying sequence, a short purge cycle was initiated to clean out the conveyor line and flush the discharge line out to the pond. The ash handling system automatically cycled through the cleaning cycle and shutdown until activated again. The system was operated in automatic mode, but could also be operated in manual mode.

Because of the alkaline nature of the sorbent, carbon dioxide was added to the ash sluice system water to maintain an acceptable pH. On-line operation of the CO_2 injection system was completely automatic; no operator interaction was required. The CO_2 injection system was not equipped with any alarms or system trips. A two-pen recorder recorded the upstream and discharge sluice water pH. The recorder was located in the boiler control room where it could be monitored routinely by the operators. The CO_2 system was controlled thru the WDPF with operator controllable setpoint, monitoring and alarming.

When the sluice pumps were started, a pressure switch closed and energized a 3-way solenoid valve. This solenoid valve provided a pneumatic signal to the CO_2 liquid automatic block valve. As long as sluice water was flowing in the line this valve remained open. If either of the two pH meters recorded a pH above the 8.5 pH set point, the pH controller sent a proportional signal to the four CO_2 injection flow control valves. The four injectors were operated in parallel unless the shutoff valves were closed.

Whenever the ash system sluice water flow is interrupted, a pressure switch will de-energize, closing the CO_2 liquid automatic block valve. The system can be shut down at any time by the operator by simply turning off the 115 volt power feed at the power panel. For long-term shutdown of the system, the operator should only turn off the 115 volt power feed. The 460 volt power feed to the CO_2 storage tank refrigeration unit may be shut off only when the tank is empty. Shutting the power off when there is CO_2 liquid in the tank will cause the to vaporize and over pressurize the tank.

As described above, the ash handling system automatically cycled through the cleaning cycle and then shut itself down until activated again. Whenever the boiler was shut down, the ash conveyor continued in operation until all fly ash hoppers had been completely emptied of fly ash and sorbent. All hoppers were then checked and cleaned out if necessary to be ready for the next start-up.

4.1.2.1 Instrumentation and Data Acquisition

The control and monitoring of the GR/SI systems as described under 4.2 - Operating

Procedures was accomplished with a Westinghouse Distributed Process Family (WDPF) control system. The WDPF system was capable of interfacing with other microprocessors. The WDPF sends and receives signals from various components in the GR/SI system.

A Boiler Performance Monitoring System (BPMS) was used to monitor operating conditions, GR–SI system performance, and unit thermal/steam production performance. The BPMS, developed by EER, is a state–of–the–art PC-based system which takes up to 300 inputs, updates these as often as every five seconds, and performs a variety of process calculations.

The Hennepin BPMS was customized to the GR–SI application and received inputs of emissions (O_2, CO, CO_2, NO_x, SO_2, and HC) as well as fuel/air input data, gas side/steam side data, and GR–SI process stream data. Table 4-6 lists typical BPMS input parameters. The BPMS performs process (combustion and heat transfer) calculations with an Excel Spreadsheet and stores the data in a desired format. The outputs are listed in Table 4-7. These include the zone stoichiometric ratios, which indicate the percent excess air in each zone, and input–output and heat loss thermal efficiency calculations according to ASME Power Test Code 4.1, Section 5, 1979. The coal flow and total air flow to the unit were calculated from a heat balance and the flue gas analysis. The fouling of heat transfer surfaces was evaluated as the ratio of the actual heat transfer coefficient to that for clean surfaces (baseline) immediately after sootblowing. These were calculated for the furnace, secondary superheater, primary superheater, reheat superheater, economizer, and air heater.

The data acquired by the BPMS were used to calculate the heat rate. The gross heat rate is the ratio of the total heat input to the gross electric power generated. The net heat rate is the ratio of the gross heat input to the power generated minus the power consumed by the plant equipment and power received by the plant from external sources.

TABLE 4-6. TYPICAL INPUT PARAMETERS FOR BPMS

CLASS OF INPUT	INPUT DATA	METHOD ACQUIRED	COMMENT
Fuel characteristics	Proximate analysis	Operator	Must be representative
	Ultimate analysis		
	Heating value		
ASME Heat Loss Method	Combustible in refuse	Operator	From design spec. or field data
	Radiation heat loss	Operator	From design spec., empirical formula
	Unmeasured heat loss	Operator	From design spec., empirical formula
Ambient Conditions	Relative humidity	Instrument Signal	
	Barometric pressure	Instrument Signal	
	Ambient temperature	Instrument Signal	
Boiler Instrumentation of Flue Gas Side	Economizer gas in. temp.	Instrument Signal	
	Economizer gas out. temp.	Instrument Signal	
	Air Heater gas out. temp.	Instrument Signal	
	Plant O_2 concentration	Instrument Signal	
GR-SI Instrumentation	FGR flow rate	Instrument Signal	
	Reburning gas flow rate	Instrument Signal	
	OFA air flow rate	Instrument Signal	
	Sorbent transport air flow rate	Instrument Signal	
	Sorbent transport air temp.	Instrument Signal	
	Sorbent transport air pressure	Instrument Signal	
	SI air flow rate	Instrument Signal	
	Sorbent mass flow rate	Instrument Signal	
CEM			
Gaseous species concentration	CO_2, CO, NO_x, O_2, SO_2,	Instrument Signal	CEMS Signal
	Hydrocarbon	Instrument Signal	CEMS Signal
Instrumentation of Combustion Air	Air heater air inlet temperature	Instrument Signal	
	Air heater air outlet temperature	Instrument Signal	
Tube Metal Temperature	At the exit of secondary SH	Instrument Signal	
Boiler Instrumentation of Water/Steam Side	Feedwater flow to economizer	Instrument Signal	
	Feedwater press to economizer	Instrument Signal	
	Feedwater temp. to economizer	Instrument Signal	
	Econo. outlet water temperature	Instrument Signal	
	Boiler drum pressure	Instrument Signal	
	Primary SH outlet pressure	Instrument Signal	
	Primary SH outlet temperature	Instrument Signal	
	SH attemp. feedwater flow	Instrument Signal	
	Secondary SH inlet pressure	Instrument Signal	
	Secondary SH inlet temperature	Instrument Signal	
	Steam press. to turbine	Instrument Signal	
	Steam temp. to turbine	Instrument Signal	
	Cold reheat flow rate	Instrument Signal	
	RH attemp. feedwater flow	Instrument Signal	
	RH inlet pressure	Instrument Signal	
	RH inlet temperature	Instrument Signal	
	RH outlet pressure	Instrument Signal	
	RH outlet temperature	Instrument Signal	

TABLE 4-7. SUMMARY OF OUTPUT FROM BPMS

CLASS OF OUTPUT	OUTPUT DATA
Calculated flue gas temperatures	Secondary SH Inlet Reheater Inlet Primary SH Inlet
Fuel heat input	From coal From GR
Heat rate	Net heat rate
Heat absorptions and cleanliness factors	Furnace Secondary SH Reheater Primary SH Economizer Air Heater
Complete combustion calculation	Stoichiometric air Stoichiometric ratio (i.e. Air number) Flue gas composition
Boiler efficiency based on ASME heat loss method	Heat loss due to dry gas Heat loss due to moisture in fuel Heat loss due to H_2O from combustion of H_2 Heat loss due to combustible in refuse Heat loss due to radiation Heat loss due to unmeasured loss
Boiler efficiency based on heat absorption method	Efficiency based on gross heat input Efficiency based on net heat input
Emissions control data	Gaseous species concentration of CO_2, CO, NO_x, O_2, SO_2, and HCs quantified in Volume concentration (% or ppm) Corrected to 3% O_2 Pounds per million Btu heat input

Detailed measurement formats were used for a thorough evaluation of the GR–SI process and the impact on various areas of boiler performance. Four measurement formats were used to evaluate the impacts of GR–SI operation. Figure 4–1 is an overview of the measurements taken.

Table 4-8 lists the instruments used for gas analyses. A continuous gas sampling system was used to measure the flue gas concentration of O_2, CO, CO_2, HC, NO_x, and SO_2. Flue gas was sampled out at the economizer inlet and at the breeching. The same gas analyzers were used, but separate sampling systems were installed at these locations and a control valve was used to switch the location being sampled.

TABLE 4-8. CONTINUOUS EMISSIONS MONITORS USED AT HENNEPIN

Species	Manufacturer	Model No.	Stream	Location
O_2	Servomex	1400	Flue Gas	Econ. Inlet
CO_2	Milton Roy Fuji	3300	Flue Gas	Econ. Inlet
CO	TECO	48	Flue Gas	Econ. Inlet
NO_x	TECO	10AR	Flue Gas	Econ. Inlet
SO_2	DuPont	400	Flue Gas	Econ. Inlet
HC	JUM Eng'r.	VE-7	Flue Gas	Econ. Inlet

At the economizer inlet a 16-point gas extraction grid was used; sampling at the breeching was from a single central point. Rotameters were used to monitor the gas flow rate from the 16-point sampling grid so that equal samples were obtained from each point, thereby accounting for gas stratification at the sampling point. Because of the large amount of particulate matter at the economizer, the sampling system made use of phase discrimination probes, whereby small amounts of gas were drawn without the particulate matter. This was required to prevent SO_2 reaction with active particulate matter, much of which is unreacted CaO during SI. The economizer outlet gas analyses were compared to flue gas composition obtained at the breeching.

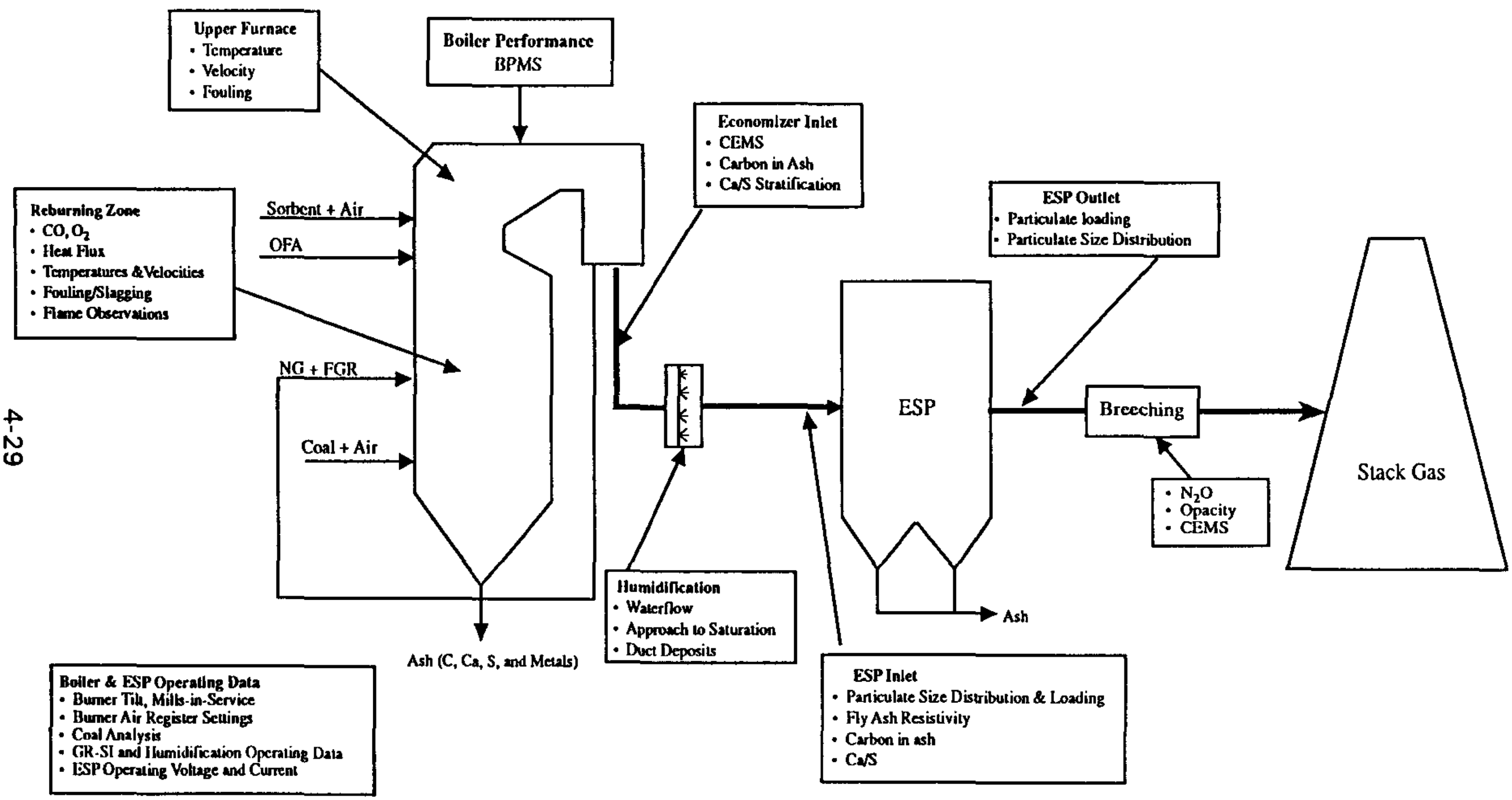


Figure 4–1. Measurement overview

Routine CEMS sampling system bias checks were performed to determine system integrity. The measured emissions of O_2, CO_2, SO_2, NO_x, and CO were also compared to EPA reference method results. These were obtained according to EPA Methods 3, 6,7 and 10. The results showed that the CEMS measurements were within the relative accuracy goal of 20% having a relative accuracy of 2.9 to 9.7%.

A comparison of measured SO_2 and CO_2 emissions for GR operation, compared to theoretical emissions based on coal composition was also carried out. The GR data showed an average difference for SO_2 of 3.49% and an average difference for CO_2 of 2.29%. The differences were due to sulfur retention in ash, carbon loss, CO emissions, and instrument error. For the SI comparison, the data showed that the average measured SO_2 emissions were within 1.68% from the theoretical SO_2 emissions and that the average CO_2 emissions were within 1.94% of the theoretical CO_2 emissions.

4.1.2.2 Test Methods

A Boiler Performance Monitoring System (BPMS) was used to monitor operating conditions, GR-SI system performance, and unit thermal/steam production performance. The BPMS, developed by EER, is a state-of-the-art PC-based system which takes up to 300 inputs, updates these as often as every five seconds, and performs a variety of process calculations. The Hennepin BPMS was customized to the GR-SI application and received inputs of emissions (O_2, CO, CO_2, NO_x, SO_2, and HC) as well as fuel/air input data, gas side/steam side data, and GR-SI process stream data. The CEMS was used to measure the flue gas concentration of O_2, CO, CO_2, HC, NO_x, and SO_2. Gas sampling was carried out at the economizer inlet and at the outlet of the ESP.
Table 4-9 lists the methods used, the relative standard deviation, tolerance and completeness of the measurements. Both the BPMS and CEMS data were taken continuously. Coal samples were taken on a daily basis during the pre-outage test period (5/91 to 9/91) and on a weekly basis during the post-outage test period (11/91 and thereafter). The sampling schedule for emissions monitoring at Hennepin is shown in Appendix B, Tables 1 and 2.

TABLE 4-9. GR–SI PROGRAM OBJECTIVES FOR MEASUREMENTS

Measurement Parameter	References	Precision RSD (%)	Tolerance (%)	Completeness (%)
Coal:				
Proximate	ASTM D3172	10	90	90
Volatiles	ASTM D3172	10	90	90
Fixed Carbon	ASTM D3172	10	90	90
Moisture	ASTM D3172	10	90	90
Ash	ASTM D3172	10	90	90
Ultimate:				
Carbon	ASTM D3176	2	98	90
Hydrogen	ASTM D3176	5	95	90
Nitrogen	ASTM D3176	10	90	90
Ash	ASTM D3176	10	90	90
Sulfur	ASTM D3176	10	90	90
Coal Ash:	ASTM D3174	10	90	90
Elemental	ASTM D2995	10	90	90
Fusion Temperature	ASTM D1857	10	90	90
Heating Value:	ASTM D2015	2	98	90
Calcium:	ASTM D2795	10	90	80
Sorbent:				
Calcium	ASTM D2795	10	90	90
Sodium	ASTM D3684	10	90	90
Magnesium	ASTM D3684	10	90	90
Potassium	ASTM D3584	10	90	90
Particle Size Distribution	ASME PTC 28	5	95	90
Specific Sufrace Area	ASME PTC 28	5	95	90
Furnace Measurement:				
Gas Temperature		5	95	90
Gas Velocity		10	90	90
Fouling Rate		10		90
Furnace Radiation		10		90

ASTM: American Society of Testing Materials
PTC: Performance Test Code
CFR: Code of Federal Regulations
RSD: Relative Standard Deviation

TABLE 4-9. GR–SI PROGRAM OBJECTIVES FOR MEASUREMENTS (CONTINUED)

Measurement Parameter	References	Precision RSD (%)	Tolerance (%)	Completeness (%)
Gas Composition:				
Oxygen	EPA	2	80	90
Sulfur Dioxide	Performance	2	80	90
Carbon Monoxide	Specifications	2	80	90
Carbon Dioxide	2 and 3	2	80	90
Nitrogen Oxides	"	2	80	90
Hydrocarbons	"	2	80	90
Sufur Trioxide	EPA Method 8 40 CFR 60 App. A	10	90	90
Nitrous Oxide	—	10	80	80
Hydrogen Chloride	EPA Method 26 (proposed)	10	90	90
Flyash:				
Elemental	ASTM D2785	10	90	90
Calcium	ASTM D2785	10	90	90
Sulfur	ASTM D2785	10	90	90
Ash:	ASTM D3174	10	90	90
Elemental	ASTM D2795	10	90	90
Fusion Temperature	ASTM D1857	10	90	90
Loading	EPA Mehtod 5 40 CFR 60 App. A	10	90	90
Particle Size Distribution	EPA 600/2–77–004	10	90	90
Resistivity		10	90	90
Other Measurements:				
Coal Feedrate	—	5	90	90
Combustion Air	—	5	90	90
FGR Flow	—	5	90	90
Sorbent Injection Air		5	90	90
Feedwater and Steam Flowrates, Temperatures, and Pressures	—	5	90	90
Sluice Line Water Flow	ASTM D3370	5	90	90
Sorbent Flowrate	—	5	90	90

ASTM: American Society of Testing Materials
PTC: Performance Test Code
CFR: Code of Federal Regulations
RSD: Relative Standard Deviation

4.1.3 Analyses of Feedstocks, Products and Reagents

Typical proximate and ultimate analyses for the coal used at Hennepin are listed in Table 4-10. Over the project, the carbon content of the coal varied between 59.9% and 67.4%, ash content varied between 9.5% and 13.0%, and the moisture content ranged from 3.9% to 14.5%. Fuel nitrogen content varied from 1.1% to 1.3% and sulfur content was in the range of 2.8% and 3.4%. Moisture content varied with the month the coal was sampled. In summer months, coal samples were generally low in moisture content (9.3%). In the fall and winter months, coal samples had a relatively high moisture content (15.1%). The higher heating value (HHV) of the coal varied between 11,329 Btu/lb coal (26,333 kJ/kg) and 10,583 Btu/lb coal (24,599 kJ/kg) due primarily to the variation in moisture content. A typical coal ash analysis is also shown in Table 4-10. The analysis of the natural gas used as the reburning fuel at Hennepin is shown In Table 4-11. In Table 4-12, chemical and physical analyses are presented for the hydrated lime sorbents used in testing, Marblehead and Linwood.

4.1.4 Data Analysis Methodology

Data quality and completeness are essential to the success of any program. Therefore, steps were taken to insure that accurate and complete data were taken. These steps included:

- Administration of QA/QC activities by a corporate Quality Assurance Officer (QAO) and a program QAO
- Preparation and implementation of a Quality Assurance Project Plan (QAPP) that specified the sampling and analytical techniques to be used and the QA/QC activities required, precision and accuracy goals, methods of QA/QC reporting, and corrective steps. The QA plan was prepared in accordance with the EPA Quality Assurance Management Staff (QAMS), as described in "Interim Guidelines and Specifications for Preparing Quality Project Plan," QAMS–005/80 (December 29, 1980).

TABLE 4-10. HENNEPIN COAL ANALYSES

Proximate Analysis:	As Received
Moisture, wt%	13.11
Ash, wt%	10.18
Volatile, wt%	35.76
Fixed Carbon, wt%	40.95
	100.00
Btu/lb, HHV	10,895
Sulfur, wt%	2.96

Ultimate Analysis:	As Received
Moisture, wt%	13.11
Carbon, wt%	60.38
Hydrogen, wt%	4.13
Nitrogen, wt%	1.16
Sulfur, wt%	2.96
Ash, wt%	10.18
Oxygen, wt%(by diff.)	8.08
	100.00

Ash Analysis:	Wt%,Ignited Basis
SiO_2	50.18
Al_2O_3	19.29
TiO_2	0.96
Fe_2O_3	16.02
CaO	3.87
MgO	1.10
K_2O	2.13
Na_2O	1.10
SO_3	3.19
P_2O_5	0.17
SrO	0.02
BaO	0.45
MnO_2	0.10
Undetermined	1.42
	100.00

Ash Analysis:	
Silica Value	70.51
Base:Acid Ratio	0.34
T_{250} Temperature	2486°F
Fouling Index	0.37
Slagging Index	1.16

TABLE 4-11. NATURAL GAS FUEL ANALYSES

Composition	Volume %
CH_4	89.83
C_2H_6	4.29
C_3H_8	0.82
C_4H_{10}	0.00
C_5H_{12}	0.00
CO_2	0.57
N_2	4.49
	100.00

Higher Heating Value (HHV) = 1,014 Btu/scf

TABLE 4-12. SORBENT ANALYSES

Constituent	Units	Marblehead	Linwood
$Ca(OH)_2$	wt%	90.00	96.20
$Mg(OH)_2$	wt%	1.60	0.14
$CaCO_3$	wt%	6.10	1.22
SiO_2	wt%	1.10	1.66
Fe_2O_3	wt%	0.60	0.50
Al_2O_3	wt%	0.30	0.60
SO_3	wt%	0.20	0.08
Surface Area	m^2/g	22	15.5
Mass Median Diameter	μ	5.00	2.88
Density	g/cm^3	2.35	2.18
Bulk Density, Loose	lb/ft^3	20-25	25
Bulk Density, Settled	lb/ft^3	30-35	30

Goals for data precision and tolerance were established for both input parameters and performance results. Table 4-9, previously presented, listed the goals for each measurement. Standard reference methods are included. These were used to evaluate the tolerance of measurements. The measurement tolerance is defined as the ratio of the measured value to the value obtained by a reference method (multiplied by 100). The precision is an indicator of the ease with which a value may be reproduced. It is quantified by the Relative Standard Deviation (RSD), which is the ratio of the standard deviation to the mean (multiplied by 100). Data completeness is an indicator of the ratio (or percentage) of the data set which is required in a valid data set. It is simply the ratio of the number of measurements to the total number required for a valid set.

The data quality goals were established commensurate with program goals and instrument accuracy. A variety of readings/measurements were qualitative or otherwise had no relative accuracy determination. Measurements such as fouling rate, furnace radiative heat flux, and particulate matter emissions and size were determined without relative accuracy. Particulate matter emissions and size were determined through standard methods, so that they may be compared to other results. Qualitative measurements include furnace slagging and observations of wear. Some measurements such as gas temperature, composition, and steam flow were compared to model predictions to assess data quality.

The QA/QC activities were routinely applied to measurement and analytical techniques. Reference method results, in comparison to measured values, showed that data quality objectives were being met. The results of some specific QA/QC activities are presented in this section. These include a QA/QC check of FGR and OFA flows, measured emissions and reference method results, and correlation of coal sulfur and carbon content with flue gas SO_2 and CO_2.

A QA/QC validation of FGR and OFA flows was undertaken in May 1991. The flows recorded by the BPMS were compared to flows measured with a pitot tube, in accord with EPA Method 2. The FGR flows indicated by the BPMS required re-calibration, but the BPMS OFA flows showed better agreement with the pitot tube measurements and therefore were not adjusted.

Routine CEMS sampling system bias checks were performed to determine system integrity. The measured emissions of O_2, CO_2, SO_2, NO_x, and CO were also compared to EPA reference method results. These were obtained according to EPA Methods 3, 6, 7 and 10. The results shown in Table 4-13 shows that the CEMS measurements were within the relative accuracy goal of 20%. The results show that the CEMS measurements had a relative accuracy of 2.9 to 9.7%.

TABLE 4-13. CEMS RELATIVE ACCURACY RESULTS.

Parameter	Sampling Location	Reference Method	Relative Accuracy	
			Actual (%)	Objective(%)
Oxygen	Economizer	EPA Method 3	4.91	20
Carbon Dioxide	Economizer	EPA Method 3	2.92	20
Sulfur Dioxide	Economizer	EPA Method 6	7.17	20
Nitrogen Dioxide	Economizer	EPA Method 7	7.51	20
Carbon Monoxide	Economizer	EPA Method 10	9.68	20

A comparison of measured SO_2 and CO_2 emissions, under baseline and GR operation, to theoretical emissions based on coal composition. The baseline results showed that the average measured SO_2 emissions were on average within 1.68% from the theoretical SO_2 emissions and that the average CO_2 emissions were within 1.94% of the theoretical CO_2 emissions. The GR data showed an average difference for SO_2 of 3.49% and an average difference for CO_2 of 2.29%. The differences were due to sulfur retention in ash, carbon loss, CO emissions, and instrument error.

4.1.5 Data Summary

The program goals of 60% NO_x reduction and 50% for SO_2 reduction were consistently achieved during the one-year technology demonstration. Over this long-term demonstration period, the average NO_x reduction was 67.3% and average SO_2 reduction was 52.6%. These correspond to emissions of 0.246 lb $NO_x/10^6$ Btu (106 mg/MJ) and 2.51 lb $SO_2/10^6$ Btu (1,080 mg/MJ). GR-SI operation also resulted in reductions in emissions of CO_2, HCl, and HF, while holding CO emissions to acceptable levels (below 100 ppm in most cases).

Optimization testing data were analyzed to establish the operating conditions under which the long term target emission levels could be achieved. Several parameters were established, including the primary zone stoichiometric ratio, reburning zone stoichiometric ratio (and corresponding percent gas heat input), FGR flow rate, and the Ca/S molar ratio. To achieve the target NO_x and SO_2 emissions while maintaining low CO emissions, the nominal operating conditions for the long-term demonstration were established as: Primary Zone SR = 1.10, Reburning Zone SR = 0.90, Burnout (Exit) Zone SR = 1.20, Gas heat input = 18%, and Ca/S molar ratio = 1.75. The unit was operated by plant personnel; the emissions and performance monitoring was conducted by EER.

Seventy-six GR-SI tests were carried out to verify the system performance over an extended period. The tests were conducted both at constant loads and with the system under dispatch operation, where the load varied to meet the plant power output requirement. The tests varied in duration, from less than one hour to over 55 hours of continuous GR-SI operation, with a typical duration of 4 to 8 hours. Over the long-term testing period, the average operating parameters were maintained close to the operating goals, as illustrated below:

Operating Parameter	Actual	Operating Goal
Primary Zone Stoichiometric Ratio	1.09	1.10
Reburning Zone Stoichiometric Ratio	0.91	0.90
Burnout (Exit) Zone Stoichiometric Ratio	1.21	1.18
Gas Heat Input	18.2%	18.0%
FGR Flow (scfm)	2,811	2,800
Ca/S Molar Ratio	1.76	1.75

The average test load varied from a low of 44 MW_e to a maximum of 75 MW_e. Over the long-term testing period the average steam load was 461,000 lb/hr (58.1 kg/s), corresponding to an average gross power output of 62 MW_e.

The test data for GR, SI and GR-SI are shown in tabular form in Appendix C. The tables in the appendix show specific test periods for daily operating conditions, thermal impacts and gaseous emissions. Additional information and detail can be found in Section 5 of this report and in Sections 6, 7 and 9 of Volume 2 - Gas Reburning-Sorbent Injection at Hennepin Unit 1.

4.1.6 Operability and Reliability

The GR-SI system worked very well during the long term testing; however, certain limitations were experienced in two areas of operation: sootblowing (SI) and humidification (SI). The first area was improved by optimization of sootblowing cycles. Significant fouling of superheater and reheater surfaces, determined from reduction in heat transfer rates during SI operation, required optimization of sootblower operation. SI resulted in reduction in thermal efficiency, increase in boiler exit temperature, and superheater attemperation rate.

During start-up of the humidification system, it was determined that the water from the lowest set of nozzles was not vaporizing as rapidly as it should, resulting in significant wall wetting. Therefore, the use of the lower set of nozzles was discontinued and humidification was applied with 22 nozzles, a capacity of 38.7 gpm (2.44 l/s) with nominal flow of 1.76 gpm (0.11 l/s) through each. During periods of high load SI operation, water flow reached its capacity. Therefore, an improvement in the humidification configuration or nozzles should result in greater ESP enhancement.

While humidification was applied successfully, especially at low load, some deterioration of ESP performance was apparent during extended full load GR-SI operation. Continuous full load GR-SI operation was limited to 32 hours, due to elevated stack opacity approaching the 30% limit. The stack opacity during this run approximated 15 to 20% when sootblowers were not in operation and 25% while sootblowing, which was conducted 84% of the time.

During long-term testing, several design features of the Hennepin GR-SI system were noted for their beneficial or adverse impacts on emissions/operations. These included the coal zone residence time, OFA injection velocity, and the sootblowing cycles. Emissions of NO_x were lower when coal burners were tilted downward, as was the case for full-load GR operation but not GR-SI operation. At low load, the OFA injection velocity was insufficient to rapidly mix with reburning zone gas, resulting in elevated CO emissions. The original sootblowing cycles required optimization to reduce boiler exit gas temperature and limit attemperation rates.

One of the design features which appears to impact NO_x emissions is the coal zone residence time. This is a function of the coal burner tilt angles, the reburning fuel tilt angles, and the distance between the reburning fuel injectors and the coal burners. Under full load GR operation, the coal burners were generally tilted downward, while under full load GR-SI operation the burners were tilted upward to maintain reheat steam temperatures. The upward tilting of coal burners resulted in a reduction in the coal zone residence time and reduced the reburning process efficiency.

The reburning fuel tilting mechanism, which was removed after optimization testing, allowed the reburning fuel to be introduced into the furnace at the same angle as the coal burners, thereby enhancing zone separation. But reburning fuel injector tilting had only a minor effect on NO_x emissions. NO_x emissions during GR-SI operation were somewhat higher than under GR. The burner tilt angles were generally below -20 degrees (downward) during full load GR operation. Therefore, the impact of the reburning fuel tilting mechanism is limited, while the burner tilt angle appeared to have significant impact on NO_x emissions. This indicates that lower NO_x emissions are obtained when there is greater separation of primary combustion and reburning fuel injection.

Elevated emissions of CO (above 100 ppm) were measured during low load GR-SI operation. While the stoichiometric ratios appeared to show sufficient burnout air for complete combustion, the injection velocity was below that required to rapidly mix with the furnace gas and burn out CO. The design studies showed that a significant drop-off in injection velocity would result from operation at reduced load, i.e. at 50% boiler load (approximately 40 MW_e) the injection velocity drops to 50% of the full load case. Therefore, the mixing rate is significantly reduced at low load, resulting in lower burnout of CO.

Fouling of convective heat transfer sections during GR-SI operation resulted in an increase in the boiler exit gas temperature, lower thermal efficiency, and higher superheater attemperation rates (due to greater heat transfer to the primary superheater). The eight IK sootblowers installed in the convective heat transfer section required optimization. The addition of these sootblowers was expected to result in an increase in sootblowing time to 50%, from the original 12%. In practice an increase in the sootblowing time to 84% was required during full load GR-SI operation to maintain a relatively constant boiler exit gas temperature, constant heat loss efficiency, and reduced superheater attemperation rates.

During the field test, twin-fluid atomization nozzles designed by EER were tested in the Hennepin humidification duct. The EER nozzles, called VEER-Jet™, were effective in reducing wall wetting. This was determined by measurement of duct skin temperature in the east and west duct, when the VEER-Jet nozzles were used in the east duct and the normal Delavan nozzles were used in the west duct. The average duct skin temperature in the east duct was 273°F (134°C) when the water flow in the duct was 12.6 gpm (0.79 l/s), while the average duct skin temperature in the west duct was 251°F (122°C) when the water flow in the west duct was 10 gpm (0.63 l/s). These results are summarized in the table below. The drop size distribution from a scaled down version of the nozzles was obtained using a Malvern instrument. A SMD of under 25 microns for water flow of 0.8 gpm (0.050 l/s) and air to water ratio of 0.1, is significantly smaller than those from most commercially available nozzles. Therefore, use of VEER-Jet™ nozzles would permit injection of a greater quantity of water which should allow continuous full load GR-SI operation without a time limit.

Another area in which the original technology was improved upon was the use of advanced proprietary sorbents. SI operation over the load range of 40 to 50 MW_e at Ca/S molar ratio of 1.75 resulted in calcium utilization of 26% for Linwood hydrated lime. The utilization increased to 31% with PromiSORB™ A and 38% with PromiSORB™ B.

HSAHL (High Surface Area Hydrated Lime), which is produced by the Illinois State Geological Survey, also showed improved performance, with an average utilization of 34%. PromiSORB™ B utilization was above 40% under a Ca/S molar ratio of 1.5, in the above stated load range. A gas temperature effect evident from operation at high loads and GR operation was evident with these promoted sorbents. Therefore, use of these advanced sorbents could yield much higher utilization and corresponding SO_2 reductions, in comparison to conventional sorbents.

Although the SI system created certain operational problems, there were no critical component failures during the course of operation of the GR-SI system.

4.2 Lakeside GR-SI Demonstration

The GR-SI demonstration at Lakeside Unit 7 was performed according to a test plan prepared in Phase I of the project. The plan outlined the number of tests, test conditions, duration of tests, and the measurements to be taken. The plan also prescribed short parametric tests to optimize the GR-SI system performance and long-term tests to verify its performance over a one-year period during the units normal duty cycle. The host unit is a cyclone coal-fired unit. It is normally operated only five months per year: April, June through August, and October. GR-SI testing was designed to conform to this operating schedule.

Measurements were recorded/calculated with EER's state-of-the-art Boiler Performance Monitoring System (BPMS) which records data such as process stream inputs (coal, cyclone air, natural gas, FGR, OFA, sorbent, SI air), flue gas temperature and pressure at several locations, feedwater flow, steam temperature and pressure, and a variety of other parameters. The BPMS calculated the heat transfer to each heat exchanger and Heat Absorption Ratios (HAR), which relate the heat absorbed under the test condition to that under baseline operation. Boiler efficiency was calculated according to heat losses as well as heat input and output.

The BPMS also recorded the measurements of the Continuous Emissions Monitoring System (CEMS) gas analyzers, which were used to characterize flue gas constituents at the boiler exit. These data were supplemented with a variety of other measurements, such as fly ash sampling for combustible matter analysis and particulate matter sampling at the ESP outlet, to fully evaluate the impacts of GR-SI on boiler performance.

4.2.1 Test Plans

The test plan served as a blueprint for optimizing the GR-SI system performance. Testing was divided into test series designed to evaluate one process parameter at a time. GR optimization tests were designed to evaluate the full complement of GR process parameters. Following GR optimization, SI-only parametric testing was conducted. These were to be followed by GR-SI optimization tests, but since sufficient process information was obtained during the GR and SI optimization period, GR-SI long-term testing immediately followed GR and SI optimization tests.
At the conclusion of long-term testing with the baseline sorbent, an alternate sorbent, supplied by NovaCon Energy Systems of Bedford, New York, was evaluated. This test was planned to offer flexibility in sorbent selection for future demonstrations or commercial applications of the technology.

4.2.1.1 Short Term Tests

GR-SI system optimization was conducted through parametric testing over a wide range of loads. Table 4-17 lists the GR process parameters and the ranges prescribed for evaluation in the test plan. Table 4-18 is a similar table for SI-only testing.

Table 4-19 lists the actual ranges of each parameter evaluated in the field for GR-SI conditions. Each parameter was evaluated individually, i.e. several tests were conducted daily, typically of one hour duration, in which a single operating parameter was varied as widely as practical. The tests were preceded by determination of baseline emissions/boiler performance and each test period was preceded by a condition or load stabilization period.

Parametric testing was conducted primarily at three loads: full load (33 MW_e), mid load (25 MW_e), and low load (20 MW_e). The GR parameters evaluated included:

- Gas Heat Input

TABLE 4-14. PLANNED GAS REBURNING OPTIMIZATION TESTS AT LAKESIDE UNIT 7

Parameters	Units	FULL LOAD			75% LOAD		60% LOAD	
		Baseline	Normal Design	Evaluation Range	Baseline	Evaluation Range	Baseline	Evaluation Range
Gross Load	MWe	33	33	33	25	25	20	20
Natural Gas	% Heat Input	0	23.6	0 to 25	0	0 to 25	0	0 to 25
Recycled Flue Gas	% Total Flue	0	5	3 to 7	0	3 to 7	0	3 to 7
Overfire Air	% Combustion Air	0	22	0 to 30	0	0 to 30	0	0 to 30
Coal Zone Stoichiometry		1.08 to 1.20	1.15	1.05 to 1.15	1.10 to 1.20	1.05 to 1.15	1.10 to 1.20	1.05 to 1.15
Reburning Zone Stoichiometry		1.08 to 1.20	0.9	0.87 to 1.00	1.10 to 1.20	0.87 to 1.00	1.10 to 1.20	0.87 to 1.00
Burnout Zone Stoichiometry		1.08 to 1.20	1.15	1.05 to 1.17	1.10 to 1.20	1.08 to 1.20	1.10 to 1.20	1.08 to 1.20
Exit Zone Stoichiometry		1.08 to 1.20	1.15	1.05 to 1.17	1.10 to 1.20	1.08 to 1.20	1.10 to 1.20	1.08 to 1.20

TABLE 4-15. PLANNED SORBENT INJECTION TESTS AT LAKESIDE UNIT 7

Parameters	Units	FULL LOAD			75% LOAD		60% LOAD	
		Baseline	Normal Design	Evaluation Range	Baseline	Evaluation Range	Baseline	Evaluation Range
Gross Load	MWe	33	33	33	25	25	20	20
Ca/S		0	2	1 to 3	0	1 to 3	0	1 to 3
Injection Air	% of Combustion Air	0	5	2 to 5	0	2 to 5	0	2 to 5
Sorbent Type	Hydrated Lime or Alternate Sorbent (TBD)		Hydr. Lime	Hydr. Lime Alternate		Hydr. Lime Alternate		Hydr. Lime Alternate
Sootblowing Cycle		Normal	Varied	Varied	Normal	Varied	Normal	Varied

TABLE 4-16. TEST CONDITIONS EVALUATED AT LAKESIDE UNIT 7.

Condition	Parameter	Unit	HIGH LOAD		MID LOAD		LOW LOAD	
			Range	Average	Range	Average	Range	Average
Baseline	Gross Load	MWe	32 to 34	33	23 to 28	25	19 to 21	19
Baseline	Coal Zone SR		1.13 to 1.34	1.17	1.04 to 1.16	1.14	1.06 to 1.23	1.15
Baseline	Reburning Zone SR		1.14 to 1.35	1.18	1.04 to 1.18	1.15	1.08 to 1.24	1.16
Baseline	Burnout Zone SR		1.22 to 1.43	1.26	1.16 to 1.28	1.26	1.22 to 1.36	1.28
Baseline	Exit Zone SR		1.22 to 1.44	1.27	1.17 to 1.29	1.27	1.22 to 1.36	1.29
Baseline	OFA	%	6 to 8	7	5 to 10	9	9 to 12	10
GR	Gross Load	MWe	32 to 34	33	23 to 27	25	19 to 21	19
GR	Gas Heat Input	%	12.0 to 25.7	23.3	14.8 to 26.1	22.6	8.4 to 25.9	22.6
GR	FGR	scfm	3000 to 6000	5450	2940 to 6000	5510	3020 to 6000	5250
GR	Coal Zone SR		1.09 to 1.29	1.15	1.05 to 1.18	1.15	0.95 to 1.28	1.12
GR	Reburning Zone SR		0.83 to 1.16	0.90	0.82 to 1.03	0.91	0.76 to 1.04	0.90
GR	Burnout Zone SR		1.20 to 1.40	1.28	1.20 to 1.41	1.28	1.11 to 1.47	1.28
GR	Exit Zone SR		1.21 to 1.40	1.28	1.20 to 1.41	1.29	1.12 to 1.49	1.29
GR	OFA	%	18 to 36	30	20 to 42	29	19 to 40	30
SI	Gross Load	MWe	33 to 34	33	23 to 26	23	19 to 21	19
SI	Burnout Zone SR		1.22 to 1.24	1.23	1.19 to 1.26	1.24	1.27	1.27
SI	Exit Zone SR		1.26 to 1.31	1.29	1.23 to 1.35	1.31	1.33 to 1.40	1.36
SI	Ca/S		1.10 to 2.87	2.10	1.14 to 2.24	1.75	1.23 to 3.46	1.88
SI	Sorbent Flow	lb/hr	2820 to 7460	5240	2200 to 4630	3510	1850 to 5290	2990
SI	Injection Air	scfm	1810 to 4530	3620	1530 to 4530	2880	2020 to 4950	3180
GR-SI	Gross Load	MWe	32 to 34	33	23 to 27	24	One Test	20
GR-SI	Gas Heat Input	%	14.2 to 25.6	21.2	14.9 to 26.2	22.0	Only	22.5
GR-SI	FGR	scfm	5760 to 6000	5930	4570 to 5990	5500		6000
GR-SI	Coal Zone SR		1.13 to 1.16	1.15	1.10 to 1.20	1.15		1.16
GR-SI	Reburning Zone SR		0.87 to 1.01	0.92	0.86 to 1.00	0.92		0.93
GR-SI	Burnout Zone SR		1.24 to 1.35	1.27	1.20 to 1.35	1.27		1.35
GR-SI	Exit Zone SR		1.27 to 1.39	1.32	1.26 to 1.41	1.33		1.42
GR-SI	OFA	%	19 to 31	27	19 to 32	27		30
GR-SI	Ca/S		1.49 to 1.90	1.72	.78 to 2.70	1.88		2.10
GR-SI	Sorbent Flow	lb/hr	3080 to 4000	3510	1240 to 4130	2950		2860
GR-SI	Injection Air	scfm	1900 to 4230	3630	1780 to 4630	3480		3740

- Recycled Flue Gas
- OFA
- Coal (Cyclone) Zone Stoichiometric Ratio

These are independent variables, with reburning and burnout zone stoichiometric ratios as dependent process variables. In GR, the burnout and exit zone stoichiometric ratios are the same; the exit zone stoichiometric ratio includes SI air flow which is zero under this condition. Measurements taken during GR optimization include gaseous emissions at the boiler exit and opacity at the ESP outlet.

Boiler operation data were recorded by the BPMS, which calculated the thermal efficiency and heat absorption by each heat exchanger. Supplemental measurements include sampling of coal at each feeder, for determination of composition and heating value, and fly ash sampling at the air heater exit, for analysis of combustible matter. The design gas heat input to achieve 60% NO_x reduction was 23.6%. The test plan was based on the evaluation of gas heat inputs in the 0 to 25% range, at each load. While GR operation in the 0 to 25% gas heat input range was planned, the actual range tested at full load was 12 to 26%. At minimum load, the gas heat input was evaluated down to 8%. The GR system control limits the lower level of gas input. FGR flows of 3000 to 6000 scfm were evaluated, but flows of 5500 to 6000 scfm were most commonly used.

The design FGR flow was 5% of the total flue gas. The range prescribed for evaluation was 3 to 7%, which at full load and 25% excess air, corresponds to 2,700 to 6,100 scfm. The design coal zone stoichiometric ratio was 1.15, which was determined to be suitable for coal burnout and formation of slagging conditions in the cyclones. Since the primary zone stoichiometric ratio can significantly impact the "primary NO_x" level, the test plan specified its evaluation down to a stoichiometric ratio of 1.05. The fraction of combustion air diverted to the OFA ports under the design condition was 22%. The test plan called for evaluation of OFA up to 30% of the total combustion air. The design reburning zone stoichiometric ratio was 0.9; testing down to 0.87 was planned. A lower limit for reburning zone stoichiometric ratio is typically observed since there is potential for increase in waterwall wastage under reducing conditions.

The design burnout zone stoichiometric ratio was 1.15; testing up to 1.17 was planned. Generally, the burnout zone stoichiometric ratio is limited to reduce dry gas heat loss. This must be balanced with achieving good fuel burnout, i.e. low CO emissions and combustible matter-in-ash.

GR testing at reduced load was planned similarly, except with higher burnout zone stoichiometric ratios. At less than full load, steam generating units are typically operated with higher excess air to increase convective heat transfer which depends on flue gas mass velocity as well as temperature. The high excess air operation helped maintain the steam temperature near its design point.

The coal zone stoichiometric ratio was evaluated in the range of 1.09 to 1.29 at full load, but down to 0.95 at minimum load. The low points for coal and reburning zone stoichiometric ratios at the minimum load were short-term tests and not representative of normal GR conditions. One of the major differences between the design case and actual test conditions was in the area of burnout zone stoichiometric ratio. The design case burnout stoichiometric ratio was 1.15, but in practice burnout stoichiometric ratios exceeding 1.25 were required to maintain low CO emissions. The OFA flow was typically 30% of the combustion air, with a maximum at full load of 36%.

SI optimization testing also involved variation of process parameters over wide ranges. Again, the test plan specified testing at three loads. The Ca/S molar ratio, which had a design value of 2.0, was to be evaluated in the 1.0 to 3.0 range. The SI air, which affects the rate of dispersion and mixing in the furnace, was 5% of the combustion air in the design case. SI air variation in the 2 to 5% range was planned.

Since Linwood hydrated lime was used in the GR-SI demonstration at Illinois Power Company's Hennepin Unit 1, it was selected as the baseline sorbent for this site. An alternate sorbent test was planned to provide a data base for the performance of other sorbents. In addition to the measurements listed above, sorbent compositions were to be obtained from the supplier. Sootblowing cycles were evaluated against steam temperature and boiler efficiency.

4.2.1.2 Long-term Tests

The test plan called for long-term GR-SI testing for a period of one year. Since the unit typically operates during the spring, late summer, and fall months, a total of nine months of long-term GR-SI demonstration was realized. The GR-SI system was evaluated at a set point, while the unit operated over its normal duty cycle. GR-SI conditions were selected from evaluation of GR and SI optimization testing.

On average, the gas heat input was 21 to 22% and the FGR flow typically was in the 5500 to 6000 scfm range. At high and mid loads, the average stoichiometric ratios for the coal and reburning zones were near the design case at 1.15 and 0.92, respectively. However, more burnout air was used than in the design resulting on average in a burnout stoichiometric ratio of 1.27 and exit stoichiometric ratios of 1.32 to 1.33. At minimum load, a higher burnout zone stoichiometric ratio (excess air) was used, as is typical for steam generating units. The sorbent inputs were generally below the Ca/S design case of 2.0. At high and mid loads, the Ca/S averaged 1.72 and 1.88, respectively. The SI air flow was varied widely, but averaged in the area of 3500 to 3700 scfm for all loads.

The alternate sorbent test was conducted to provide a performance data base for sorbents other than Linwood hydrated lime. This was of relatively short duration (under one week) and over a wide range of boiler operation. Sorbent provided by NovaCon Energy Systems of Bedford, New York was tested at the conclusion of the GR-SI test program.

4.2.2 Operating Procedures

The control and monitoring of the GR/SI systems was accomplished through a Westinghouse Distributed Process Family (WDPF) control system. The system consists of a variable mix of functional units (drops) communicating freely and rapidly via the WDPF Data Highway (Westnet II). Some drops are linked to the actual plant control devices via input/output (I/O) components, and others are connected by a coaxial cable, multi-bus data highway. The WDPF system is capable of interfacing with other microprocessors. The WDPF sends and receives signals from various components in the GR/SI system.

The WDPF system supported both local and remote I/O modules for interfacing to process equipment and sensors. The wide range of input capability allows the direct connection of transmitters, thermocouples, RTD's, control dampers, control valves, manual/auto station, positioning devices, speed control, and contact to I/O modules.

The design of the GR-SI control system was based on the following criteria:

- All normal operations that were required to start, stop, or modulate the various pieces of equipment for the GR and SI systems were performed in the control room.

- Sufficient information was displayed in the control room to enable the operator to determine the status of all equipment. The operator interface was designed so that the above information was displayed in a manner to enable rapid understanding of system status.

- Certain operations were interlocked to prevent inadvertent operation of equipment when such operation may present an operating hazard or other undesirable condition.

- Certain shut-down procedures were initiated automatically by the control system when such operations were deemed necessary for safety or good operating practice.

In addition, functional control logic drawings were made for all required analog loops. Yes-No logic drawings were made for all safety and interlocking functions.

A boiler performance monitoring system (BPMS) was used to monitor operating conditions, GR–SI system performance, and unit thermal/steam production performance. The BPMS, developed by EER, is a state-of-the-art personal computer (PC) based system which takes up to 300 inputs, updates these as often as every five seconds, and performs a variety of process calculations.

The GR system was composed of three integrated systems: (1) natural gas injection, (2) FGR, and (3) OFA injection. The natural gas flow rate was controlled to the desired value for optimum NO_x destruction for any boiler load (approximately 22% of the total furnace Btu input). The FGR flow is controlled to a value established during optimization testing to give the natural gas optimum momentum for good distribution in the furnace. The OFA was controlled to a rate to provide oxygen for the complete combustion of all unburned fuel leaving the GR zone. The three integrated systems were interlocked, operated and monitored by the WDPF Control system.

The pneumatically operated valves for GR were positioned by a 4-20 milliAmp signal to the valve positioner. The positioner converts this signal to an air pressure applied to the valve diaphragm or piston to move the valve between 0% and 100% of full open. Valves used for isolation purposes (open/close only) had limit switches which provided a positive indication to the WDPF control system that valves were fully open or fully closed. Most of the signals between the valve positioners, limit switches, and the WDPF were routed from the field (on the data highway) through the signal wiring junction boxes to the WDPF.

The control logic for gas injection consisted of a flow controller which received a calculated set point from the boiler master and the natural gas flow transmitter. The boiler master controls gas flow with coal flow to obtain the BTU input needed over the load range. A percentage of the total heat input indicated by the boiler master signal was used as the set point for the desired natural gas flow. The natural gas flow was limited to the range of 10-25% of the total heat input.

The second stage of the GR system is the FGR System. The desired FGR flow control set point was a calculated value determined from the boiler master signal. This set point signal was compared with the actual FGR flow rate in a controller which acted on any detected error signal. The WDPF automatically adjusted the FGR fan to reduce the error to zero.

Additional air was added as OFA to complete the combustion process of the gases from the reburning zone. Control of the OFA system consisted of sending a set point signal calculated from the boiler master signal to a controller where it was compared with the total OFA flow. The OFA nozzles were modulated to reduce any detected difference in the set point and total OFA flow to zero. The WDPF compared the two signals from the OFA transmitters to balance the flow of air. A bias signal was added to the damper position control signal to insure equal flows through the OFA control dampers.

Another control feature of the GR system was the cross limit between the OFA flow and natural gas flow. The OFA flow setpoint was established to permit complete combustion of natural gas over the range of gas flows available.

The above sequence is called cross limiting between the fuel (natural gas) and air (OFA) and was very similar to the cross limiting features in the main combustion control between the coal feed and secondary air flow. There was another cross limit, this one between the FGR and the natural gas flow. If the FGR flow fell below a value that insured penetration of the natural gas into the boiler the set point for natural gas flow was reduced to a safe value.

The GR system would not operate below approximately 50% of boiler load. A signal from the heat release rate was used to verify boiler load. As an added safety interlock, the furnace temperature in the gas injection zone had to be above the auto ignition temperature for natural gas. Two out of three temperature transmitters had to be above 1700°F to satisfy the safety interlock. Any of the conditions below caused the natural gas block & bleed valves to close and the gas vent to open. The startup and shutdown procedures to be for the GR system are listed in Appendix A.

1. Low or High natural gas pressure
2. Load falls below minimum for reburning
3. Emergency trip GR commanded
4. Boiler trip commanded
5. Operator "Shut" Gas Shutoff Valves
6. FGR Injection Fan is not running
7. FD Fan on Unit is not running
8. Cooling air to natural gas only nozzles

The SI system had three (3) variables (4 to 20 mA control outputs) that are modulated by the WDPF control system to obtain a target sulfur emission reduction while maintaining maximum sorbent utilization. These control outputs included:

1) Rotary Feeder - Sorbent Feedrate
2) Control Valve - Sorbent Transport Air Flow
3) SI Air Flow Control Damper - SI Air Flow

The measured variables (4-20 mA control inputs) monitored and utilized in the WDPF control system to calculate the optimum control outputs were as follows:

1) Sorbent Transport Air Flow Transmitter
2) Sorbent Transport Air Temperature Transmitter
3) Sorbent Transport Air Pressure Transmitter
4) Flue Gas SO_2 Analyzer
5) Sorbent Weigh Hopper Weight
6) SI Air Flow Transmitter
7) Boiler Master Signal
8) Sorbent Feedrate (pounds/hour)

The operator setpoint for SO_2 was compared with the input from the flue gas SO_2 analyzer. The output of the controller is used as a multiplier for the "total" coal flow rate to give a sorbent flow demand rate. This calculated sorbent flow demand rate becomes a setpoint value for two control loops. The first control loop, sorbent flow demand rate, sets the initial value for sorbent feed rate controlled by the rotary feeder. In this loop it is a setpoint and is compared with the actual measured value of sorbent feed in a controller. The output of the controller modulates the speed of the rotary feeder. In the second control loop, the desired transport air flow rate is compared with the actual sorbent transport air flow in a controller which modulates the sorbent transport air flow control valve to increase or decrease amount of air flow.

The last control loop deals with the amount of SI air flow required to inject the sorbent into the upper turbulent area of boiler. The boiler master signal set the initial value to modulate the SI air flow control damper. The boiler master signal was also compared with the actual measured value of the SI air flow in a controller. Any error between the setpoint and actual flow rate is acted on by the controller whose output is summed with the initial value of the control signal to the SI air flow control damper, thereby reducing any error to zero.

4.2.2.1 Instrumentation and Data Acquisition

Data were acquired from plant instrumentation and stored by EER's customized BPMS. CEMS analyzer data were also recorded by the BPMS, which corrected these measurements to a standard O_2 concentration or to a mass per heat input basis. In addition to BPMS data, control room data for each test condition were hand recorded as a backup to storage of data by the BPMS. Manual sampling data were hand recorded on run sheets and sample custody sheets and laboratory analyses reports were provided by a commercial laboratory.

The BPMS used to monitor the performance of the GR-SI system and boiler thermal characteristics at Lakeside Unit 7 was customized for this application. The BPMS was customized to the GR-SI application and received inputs of emissions as well as fuel/air input data, gas side/steam side data, and GR-SI process stream data. It recorded a host of inputs (see Table 4-17) performed process calculations, then output data in prescribed formats. The outputs are listed in Table 4-18.

The flows of coal, cyclone air, natural gas, OFA, and SI air were used to calculate the four zone stoichiometric ratios. Utilizing standard coal and natural gas compositions. The combustion air and flue gas temperatures, standard fuel compositions, and design specifications or empirical model results were used to calculate heat loss efficiency. A combustion and heat transfer model calculated the heat absorption by each heat exchanger: furnace and wing walls, secondary superheater, primary superheater, generating bank, attemperator, and air heater. HAR, relating the heat absorbed under the specific test condition to the baseline case at the same load, were also calculated. These gave an indication of the extent of deposition on the heat exchanger surface, i.e. furnace slagging and convective pass fouling. The BPMS also compiled data output from the CEMS gas analyzers, and corrected emissions to 3% O_2 and calculated mass of emissions per heat input.

TABLE 4-17. TYPICAL INPUT PARAMETERS FOR BPMS

CLASS OF INPUT	INPUT DATA	METHOD ACQUIRED	COMMENT
Fuel characteristics	Proximate analysis	Operator	Must be representative
	Ultimate analysis		
	Heating value		
ASME Heat Loss Method	Combustible in refuse	Operator	From design spec. or field data
	Radiation heat loss	Operator	From design spec., empirical formula
	Unmeasured heat loss	Operator	From design spec., empirical formula
Ambient Conditions	Relative humidity	Instrument Signal	
	Barometric pressure	Instrument Signal	
	Ambient temperature	Instrument Signal	
Boiler Instrumentation of Flue Gas Side	Boiler bank inlet temperature	Instrument Signal	
	Boiler bank outlet temperature	Instrument Signal	
	Air Heater outlet temperature	Instrument Signal	
	Boiler outlet O_2 concentration	Instrument Signal	
GR-SI Instrumentation	FGR flow rate	Instrument Signal	
	Reburning gas flow rate	Instrument Signal	
	OFA air flow rate	Instrument Signal	
	Sorbent transport air flow rate	Instrument Signal	
	Sorbent transport air temp.	Instrument Signal	
	Sorbent transport air pressure	Instrument Signal	
	SI air flow rate	Instrument Signal	
	Sorbent mass flow rate	Instrument Signal	
CEM Gaseous species concentration	CO_2, CO, NO_x, O_2, SO_2,	Instrument Signal	CEMS Signal
	Hydrocarbon	Instrument Signal	CEMS Signal
Instrumentation of Combustion Air	East cyclone air flow	Instrument Signal	
	West cyclone air flow	Instrument Signal	
	Air heater air inlet temperature	Instrument Signal	
	Air heater air outlet temperature	Instrument Signal	
Tube Metal Temperature	Superheater tubewall	Instrument Signal	
Boiler Instrumentation of Water/Steam Side	Feedwater flow to steam drum	Instrument Signal	
	Feedwater temp. to steam drum	Instrument Signal	
	Boiler drum pressure	Instrument Signal	
	Primary SH outlet temperature	Instrument Signal	
	SH attemp. outlet temperature	Instrument Signal	
	Secondary SH outlet pressure	Instrument Signal	
	Secondary SH outlet temp.	Instrument Signal	
Power Generation	Gross power output	Instrument Signal	

TABLE 4-18. SUMMARY OF OUTPUT FROM BPMS

CLASS OF OUTPUT	OUTPUT DATA
Heat input	Total heat input Heat input to cyclones Reburning gas heat input
Heat absorption	Furnace, including wing walls Secondary SH Primary SH Generating bank Drum attemperator Air Heater
Boiler efficiency based on ASME heat loss method	Heat loss due to dry gas Heat loss due to moisture in fuel Heat loss due to H_2O from combustion of H_2 Heat loss due to combustible in refuse Heat loss due to radiation Heat loss due to unmeasured loss
Boiler efficiency based on heat absorption method	Efficiency based on gross heat input Efficiency based on net heat input
Heat Absorption Ratio (HAR) (Relative to baseline)	Furnace, including wing walls Secondary SH Primary SH Generating bank Drum attemperator Air Heater
Stoichiometric Ratio (SR)	Primary coal burning zone Reburning zone Burnout zone Exit zone
Ratio of calcium to coal sulfur	Ca/S
Emissions control data	Gaseous species concentration of CO_2, CO, NO_x, O_2, SO_2, and HCs quantified in Volume concentration (% or ppm dry) Corrected to 3% O_2 Pounds per million Btu heat input

During the field demonstration tests at Lakeside, detailed measurements were performed at nominal operating conditions and at selected conditions during GR-SI operations. An overview of the measurements is shown in Figure 4-2. As shown, the field demonstration tests consisted of monitoring and recording boiler and ESP operating and performance data, performing continuous emissions monitoring at the boiler exit or the ESP outlet, determining particulate size distribution and loading and fly ash resistivity at the ESP inlet and outlet, conducting gas temperature, velocity, and composition measurements through several ports in the boiler furnace, and surveying slagging/fouling patterns at several locations in the boiler furnace.

Lakeside Unit #7 shares the same ESP and stack with Unit #8. For baseline and GR operation, flue gas sampling for the CEMS was sampled at Unit #7 boiler exit so that Unit 8 did not interfere with the CEMS analysis. For SI and GR-SI operation testing, Unit #8 was not in operation, and the flue gas for the CEMS was sampled at the ESP outlet to avoid probe plugging.

4.2.2.2 Test Methods

Data were acquired from plant instrumentation and stored by EER's customized BPMS. CEMS analyzer data were also recorded by the BPMS, which corrected these measurements to a standard O_2 concentration or to a mass per heat input basis. In addition to BPMS data, control room data for each test condition were hand recorded as a backup to storage of data by the BPMS. Manual sampling data were hand recorded on run sheets and sample custody sheets and laboratory analyses reports were provided by a commercial laboratory. The BPMS used to monitor the performance of the GR-SI system and boiler thermal characteristics at Lakeside Unit 7 was customized for this application.

EER's BPMS heat transfer and combustion model can receive up to 300 inputs and update them as frequently as every 5 seconds. It can perform process calculations including heat absorptions by various heat exchangers, gas temperature changes, heat loss efficiency, and emissions correction to standard O_2 and in terms of mass per heat

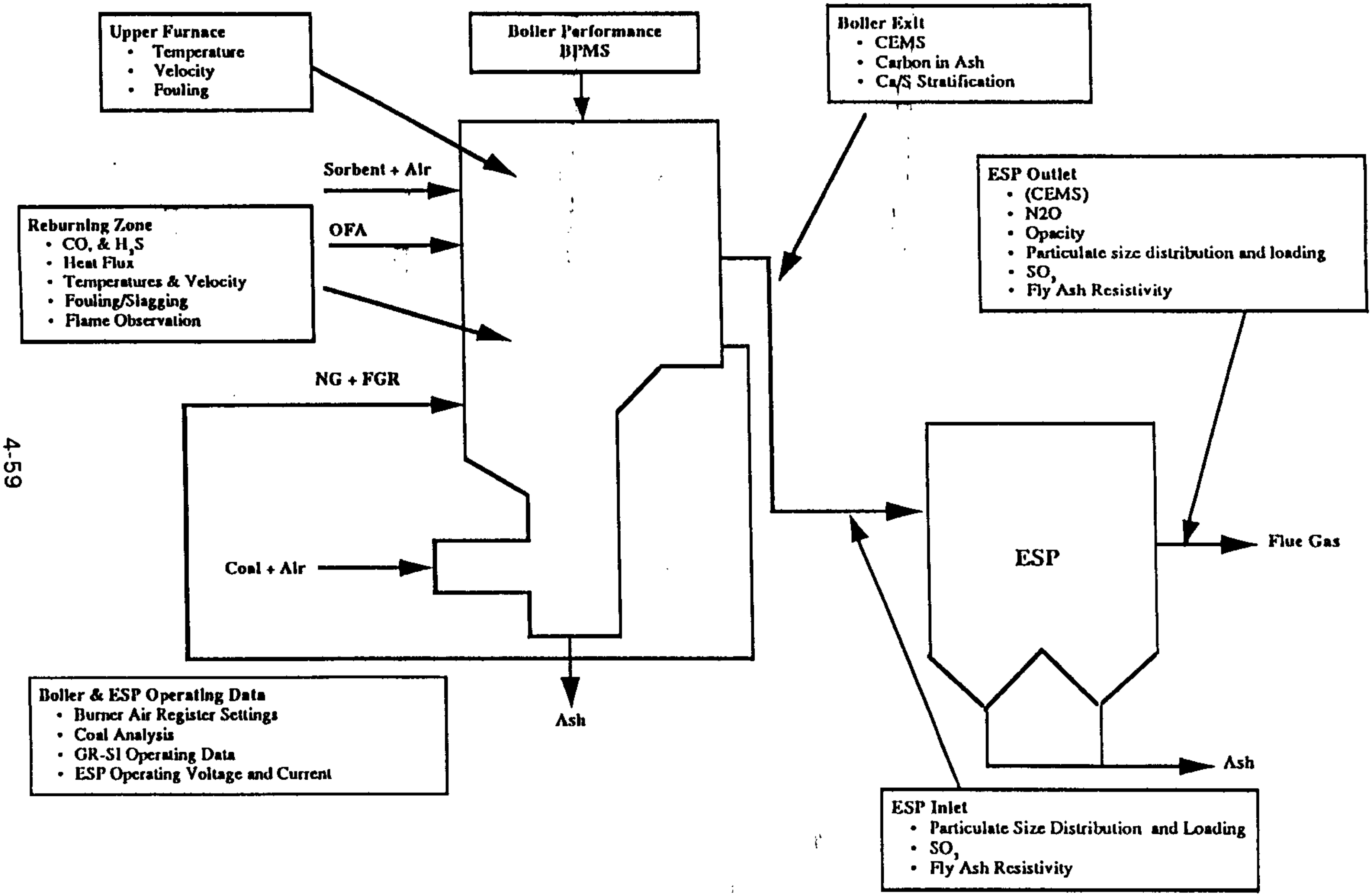


Figure 4-2. Measurement Overview for Lakeside Unit #7.

input. It can calculate the coal flow based on steam heat absorption and the input-output efficiency equivalent to the heat loss efficiency. It displays data on-line for real time trending and archives data on an optical disk. It also has capability for remote monitoring of data and file exchange. The Lakeside BPMS provided one minute average data that were compiled over the test periods.

A CEMS was used to continuously monitor gaseous emissions at the boiler outlet. The CEMS measured concentrations of NO_x, SO_2, CO, CO_2, and O_2. Early in the test program, measurements of total hydrocarbon (HC) were also taken. Due to the rigorous demands of sampling flue gas, which were anticipated, HC measurements were taken only during early GR optimization tests. The O_2 measurement was used to correct the emissions of NO_x and SO_2 to the standard 3% O_2 concentration. The CO_2 measurement was used verify the O_2 concentration based on a carbon mass balance. The CO concentration, which is typically below 200 ppm for coal fired units, is an indicator of combustion completion.

Flue gas was extracted from a sixteen point grid at the boiler exit. The CEMS used a stainless steel sampling grid, heated lines to prevent moisture condensation, rotameters to balance gas flow, a mixing manifold, a chiller for moisture removal, and the analytical instruments calibrated with zero, mid-span and span gases. During periods of SI operation, phase discrimination probes were used to separate particulate from the gas sampled. This ensured that SO_2 in the sampling system did not interact with reactive particulate (sorbent). The same sampling methods that were used at Hennepin were used at Lakeside. Table 4-9, shown previously, lists the methods, the relative standard deviation, tolerance and completeness of the measurements. Both the BPMS and CEMS data were taken continuously. The emissions monitoring sampling schedule for Lakeside is shown in Appendix B, Tables 3 and 4.

4.2.3 Analyses of Feedstocks, Products and Reagents

Typical proximate and ultimate analyses of coal fired at the Lakeside Station are shown in Table 4-19. It is a slagging type coal, i.e. it has relatively low ash fusion temperatures, suitable for firing in cyclone furnaces. The composition of the natural gas used as the reburning fuel is shown in Table 4-20.

TABLE 4-19. TYPICAL LAKESIDE COAL ANALYSES

Proximate Analysis:	As Received	Ultimate Analysis:	As Received
Moisture, wt%	17.78	Moisture, wt%	17.78
Ash, wt%	9.94	Carbon, wt%	56.96
Volatile, wt%	33.62	Hydrogen, wt%	4.01
Fixed Carbon, wt%	38.66	Nitrogen, wt%	1.06
	100.00	Sulfur, wt%	3.00
		Ash, wt%	9.94
Btu/lb, HHV	10,300	Oxygen, wt%(by diff.)	7.25
Sulfur, wt%	3.00		100.00

Ash Fusion Temperatures:	
Reducing Atmosphere	
Initial Deformation	1930°F
Ash Softening	2000°F
Ash Hemispherical	2150°F
Ash Fluid	2260°F

TABLE 4-20. NATURAL GAS FUEL ANALYSES

Normalized Composition	Volume %
CH_4	87.99
C_2H_6	4.00
C_3H_8	1.37
C_4H_{10}	0.29
C_5H_{12}	0.78
CO_2	0.56
N_2	5.01
	100.00

Higher Heating Value (HHV) = 1,035 Btu/scf

The makeup of Linwood hydrated lime sorbent, i.e. $Ca(OH)_2$ and free H_2O content, was determined by the supplier. The average $Ca(OH)_2$ content was 96.2, while the average free moisture content was 0.8%. A detailed composition of the Linwood hydrated lime was shown previously in Table 4-12.

4.2.4 Data Analysis Methodology

The same quality control/assurance procedures used at Hennepin were implemented for the Lakeside test program. A discussion on these procedures is delineated in Section 4.1.4.

The emissions reduction performance of the GR and SI systems was correlated to process parameters. The NO_x control achieved with GR was related to gas heat input, reburning zone stoichiometric ratio, and coal zone stoichiometric ratio. The SO_2 control achieved by SI was correlated to Ca/S and SI air flow.

The following discussion identifies the major GR process variables which have to be fixed in order to set up the system to emit a consistent and reproducible NO_x level. The major process parameters in GR are the zone stoichiometric ratios. These are defined by the following equations.

$$SR_1 = (TA - OFA)/CSA \quad (1)$$

$$SR_2 = (TA - OFA)/(CSA + GSA) \quad (2)$$

$$SR_3 = TA/(CSA + GSA) \quad (3)$$

Where:

TA = Total Air (scfm)

OFA = OFA (scfm)

CSA = Coal Stoichiometric Air (scfm) = coal theoretical air (scf/lb) x coal flow (lb/min)

GSA = Gas Stoichiometric Air (scfm) = gas theoretical air (scf/scf) x gas flow (scfm)

Under GR operation, the SI air is limited to nozzle cooling flow; therefore, it was neglected here.

The above equations may be rearranged to yield the following:

$$\text{Coal air fraction} = (TA - OFA)/TA = SR_2/SR_3 \quad (4)$$

$$\text{OFA fraction} = OFA/TA = (SR_3 - SR_2)/SR_3 \quad (5)$$

In addition, the following approximations are presented. These are useful for data correlation purposes only and were not used to actually calculate these parameters.

$$\text{Coal fraction} = CSA/(CSA + GSA) = SR_2/SR_1 \quad (6)$$

$$\text{Natural Gas fraction} = 1 - \text{Coal fraction} = (SR_1 - SR_2)/SR_1 \quad (7)$$

Therefore, seven process variables (SR_1, SR_2, SR_3, coal fraction, natural gas fraction, coal air fraction, and OFA fraction) are related by four equations (4 though 7). To fix the system, three variables must be held constant. Examples of sets of process variables which define a fixed system include (SR_1, SR_2, SR_3), (SR_1, natural gas fraction, SR_3), and (SR_1, SR_2, OFA fraction).

In plotting NO_x as a function of natural gas fraction or SR_2, two process variables should be held constant. In such plots, the variables most commonly held constant are SR_1 and SR_3. Alternatively, two other variables which may be held constant are SR_1 and OFA fraction. Holding two variables constant in data plots results in a minimum of data scattering and permits reproduction of trends. The rate of SI was simply determined by the rate of coal feed and the Ca/S ratio desired for the test period.

4.2.5 Data Summary

The test data for GR, SI and GR-SI are shown in tabular form in Appendix C. The tables in the appendix show specific test periods for daily operating conditions, thermal impacts and gaseous emissions. Additional detailed information can be found in Section 5 of this report and Sections 7, 8, and 9 of Volume 4 - Gas Reburning-Sorbent Injection at Lakeside Unit 7.

4.2.6 Operability and Reliability

In this section the impacts of the co-application of GR and SI on boiler performance areas other than heat transfer efficiency are discussed. These include furnace slagging, convective pass fouling, and ESP performance. In order to assess the impact of gas GR-SI on the boiler, a series of inspections were performed both prior to and following the GR-SI testing. The following areas were evaluated:

- Boiler tubes
- Regenerative air heater
- Electrostatic precipitator
- Chimney
- Boiler performance

These evaluations are discussed in detail in the GR-SI Boiler Impact Report, that is included as Appendix 1 in Volume 4 - Gas Reburning-Sorbent Injection at Lakeside Unit 7 - May, 1995.

Slagging in the furnace was evaluated by visual inspection of furnace conditions. In coal-fired units, buildup of slag on furnace walls is generally dependent on coal qualities such as ash fusion temperatures and boiler operating parameters such as stoichiometric ratio (excess air), gas temperature profile, and furnace wall temperatures. In the design of furnaces, slag buildup is minimized using large furnace volumes, limiting heat input per unit volume which reduces the FEGT. Since ash fusion temperatures are lower under reducing conditions, areas in the furnace which are deficient in excess air may have increased slag buildup.

In cyclone-fired units the furnaces are kept hot in order to tap molten slag through the bottom of the furnace. Typically, only 20% of the ash input exits the cyclone-fired barrels as fly ash; the majority of the ash is captured as molten slag in the cyclone barrels, then flows into the furnace where it is removed through a slag tap.

It was found through observation that the injection of natural gas and FGR promoted formation of slag patterns, i.e. there were slag accumulations around the nozzles forming "eyebrows" and on the waterwall areas above the natural gas/FGR injectors. Slag deposits were observed up to the rear section of the furnace wing walls. The sloped front wall and the upper furnace were generally free of slag, with the exception of the lower portion of the east front wall division panel.

A cleaning feature was incorporated in the GR system design, which allowed for the nozzles to be rodded out as needed to remove slag deposits on the nozzle periphery. At the beginning of each test day, the accumulations and the necessity for rodding out were assessed. Usually small amounts of slag deposits were removed weekly. The small natural gas only injectors, which were not in use during the long-term demonstration, were found to be completely obstructed.

Fouling of the convective pass due to GR-SI was quantified through heat absorption ratios (HAR) calculated by the BPMS. The HARs are not direct indicators of the extent of fouling since they do not take into account temperature changes which drive heat transfer. HAR for the secondary superheater, primary superheater, and generating bank was completed for a GR-SI test. It was evident that the increased upper furnace gas temperature due to reburning fuel heat input above the coal cyclones and the nearly continuous sootblowing used during SI operation resulted in enhanced heat absorption by the secondary and primary superheaters. For these heat exchangers the HAR's were consistently above 1.0. The generating bank HAR was, however, below 1.0 in many cases. Temperature shifts of 30°F (17°C) to 40°F (22°C) were near to those projected. Under SI, IK sootblowers were in operation between 80 to 90% of the time.

The performance of the ESP was determined through particulate sampling according to U.S. EPA Method 5 while the unit was under full load GR-SI operation. The average particulate emissions were 0.016 lb/10^6 Btu (6.9 mg/MJ), far below the 0.1 lb/10^6 Btu (43 mg/MJ) limit, with an average grain loading of 0.0080 gr/dscf (0.018 g/m^3). The grain loading is somewhat higher than that measured under baseline operation in 1988.

In those tests, with both units 7 and 8 operating at full load (66 MW_e total), the average grain loading for three runs was 0.0036 gr/dscf (0.0082 g/m^3). The flue gas moisture content, which may impact the acid dew point temperature and hence metal corrosion rate, averaged 11.46 mole%. This is an increase from the baseline flue gas moisture content of 8.89 mole%. Inspections of the ESP were conducted by contractors to determine its condition prior to initiation and after completion of the GR-SI testing. The findings are described below in the boiler inspections section.

In general, the GR-SI equipment performed well after early optimization. Several problems were encountered during start-up that required attention from CWLP or an outside contractor. These included the FGR fan, rear pass hoppers, flue gas leakage, and sootblower operation. In addition to problems in these areas, which were rectified during start-up, several problems were encountered during operation over the nine month demonstration period. Adjustments/repairs were needed in the operation of flame scanners, cyclone air transmitters, the WDPF control system, and the ash handling system.

During start-up, adjustments were made to the FGR fan, the rear pass hoppers, the retractable sootblowers and to the boiler insulation. The FGR fan clutch failed twice necessitating repair. Once adjustments to the drive and control system were made, few problems with the FGR fan were encountered throughout the rest of the testing program. The rear pass hoppers tended to plug up. When the material was dislodged, some of the ash would flow through an opening in the floor to the base of the FGR fan and interfere with the spring suspension mounts. A metal box was installed in this opening to capture the ash and hence prevent its buildup near the FGR fan mounts.

All of the retractable sootblowers were replaced during the construction phase of the project. Early problems with sagging and misalignment were corrected by the CWLP boiler crew. These efforts were successful, and the sootblowers were used almost continuously while injecting sorbent. The boiler insulation had cracks in several areas

5.0 TECHNICAL PERFORMANCE

This section presents results of GR, SI, and GR-SI testing in the areas of boiler emissions, combustion completion, thermal efficiency, steam conditions, and other performance areas. The impacts of these technologies on boiler operation including furnace slagging, convective pass fouling, and ESP performance are also addressed. The flue gas constituents at the boiler exit were characterized continuously with EER's CEMS. Test averaged emissions of NO_x, SO_2, CO, and CO_2 are presented in Appendix 2. In this section, the emissions are correlated with GR-SI system and boiler operating conditions. Following the presentation of emissions data, the impacts of GR-SI on boiler thermal performance are evaluated. It was important to quantify impacts on heat transfer efficiency, combustion completion, steam conditions, steam attemperation rate, and flue gas temperatures. These parameters were continuously recorded or calculated by the BPMS. Following the presentation of these results, GR-SI impacts on ash deposition in the furnace, fouling of convective heat exchangers with ash/sorbent, performance of the ESP, and wear of boiler components are presented. The wastage rate of boiler tubewalls was determined via Ultrasonic Thickness (UT) measurements taken before and after the GR-SI demonstration. Metallurgical examination of tubewall samples was conducted before and after GR-SI testing. Visual inspections of the cyclones, furnace, convective pass, ESP, and chimney were conducted by EER personnel and contractors to assess changes due to GR-SI. The section concludes with a discussion of adjustments made to the GR-SI system during the test program to enhance its performance.

5.1 Hennepin

5.1.1 Coal Analyses and Sorbent Composition

Ultimate analyses of coal fired at Hennepin Station pre-outage and post-outage during the GR-SI demonstration are compared with a design composition in Table 5-1. The

TABLE 5–1. COAL AND NATURAL GAS COMPOSITION

ELEMENT	units	Original Design	Pre–Outage Average	Post–Outage Average
Coal:				
Carbon	%	59.16	63.23	58.96
Hydrogen	%	3.97	4.28	4.06
Oxygen	%	7.46	8.51	7.65
Nitrogen	%	1.04	1.21	1.11
Sulfur	%	2.82	3.05	2.97
Moisture	%	15.99	8.94	15.07
Ash	%	9.56	10.78	10.18
HHV	Btu/ lb coal	10,632	11,363	10,583
Theoretical SO_2 Emissions	lb/MBtu	5.30	5.37	5.61
Theoretical Air Demand	lb air/lb coal	7.999	8.510	7.955
Natural Gas:				
CH_4	%	89.83	–	–
C_2H_6	%	4.29	–	–
C_3H_8	%	0.82	–	–
C_4H_{10}	%	0.00	–	–
C_5H_{12}	%	0.00	–	–
CO_2	%	0.57	–	–
N_2	%	4.20	–	–
HHV	Btu/scf	1,014	–	–
Theoretical Air Demand	lb air/scf	0.724	–	–

coal fired after the outage to install GR-SI equipment had a lower heating value and higher moisture content than that fired previously. The average coal sulfur content of 2.97% and carbon content of 58.96% correspond to a theoretical SO_2 level of 5.61 lb/10^6Btu and a CO_2 level of 204 lb/10^6Btu. The coal has a stoichiometric air requirement of 7.995 lb air/lb coal. It is a slagging type coal, i.e. it has relatively low ash fusion temperatures, suitable for firing in tangentially fired units.

The makeup of Linwood Hydrated Lime sorbent, i.e. $Ca(OH)_2$ was determined by the supplier. Table 5-2 lists these constituents. The $Ca(OH)_2$ content was 96.20%.

5.1.2 Gas Reburning Results

The performance of the GR system in controlling NO_x and its impacts on other gaseous emissions including CO, CO_2, and SO_2 are presented in this section. The program goal for Hennepin Unit 1 was to reduce NO_x by 60% at full load. GR operation was expected to modestly reduce CO_2 and SO_2, with no change in CO achieved, through judicious design of the OFA system. CO_2 is a major product of fossil fuel combustion and has been associated with the greenhouse global warming effect; SO_2 is precursor for acidic compounds associated with acid rain and CO is used as an indicator of combustion completion. To evaluate the GR system, parametric tests typically lasting one to two hours were conducted, with as many as seven completed in a day. Each process parameter was varied individually in order to evaluate its impact independent of the others.

5.1.2.1 NO_x Control

The NO_x reductions due to GR have been correlated with the fraction of heat input due to natural gas. The following equation represents the relationship of NO_x emissions reduction to gas heat at Hennepin Unit 1:

TABLE 5–2. SORBENT ANALYSES

Constituent	units	Marblehead	Linwood
$Ca(OH)_2$	%	90.00	96.20
$Mg(OH)_2$	%	1.60	0.14
$CaCO_3$	%	6.10	1.22
SiO_2	%	1.10	1.66
Fe_2O_3	%	0.60	0.50
Al_2O_3	%	0.30	0.60
SO_3	%	0.20	0.08
Surface Area	m^2/g	22	15.5
Mass Median Diameter	µ	5.00	2.88
Density	g/cm^3	2.35	2.18
Bulk Density, Loose	lb/ft^3	20-25	25
Bulk Density, Settled	lb/ft^3	30-35	30

$NO_xEff = 0.52 + 0.86 * RBFRAC$

where: NO_xEff = NO_x reduction expressed as a decimal (no units)

RBFRAC = Gas fired for GR divided by total boiler heat input expressed as a decimal (no units).

This is applicable for a gas heat fraction in the range of 0.10 to 0.20. GR is generally applied with gas heat input in this range.

The process parameters relevant to NO_x control by GR include the stoichiometric ratio of each zone (coal, reburning, and exit), the gas heat input, reburning fuel injection details, and the FGR flow.

5.1.2.1.1 Gas Heat Input

Gas heat inputs in the range 10 to 20% were evaluated. Figure 5-1 shows NO_x emissions at full load as a function of gas heat input. The measurements indicate that a 67.3% average reduction at full load was achieved at gas inputs of 18 to 19%. The variations in NO_x are due to ranges in the primary, reburning, and exit zone stoichiometric ratios and other parameters tested. The majority of long-term GR-SI tests were performed with gas heat in the 18 to 19 percent range, but a few tests were performed at lower gas input. Tests were conducted at 15.7 and 17.7% respectively resulting in NO_x reductions of 65.1 and 66.4%. Improved NO_x reductions were measured at low load relative to that at other loads. This is likely due to enhanced mixing of reburning fuel with the primary combustion gas under this condition to form a more uniform reducing zone. At full load the maximum NO_x reduction was 67% at a gas heat input of 18%, while at mid loads NO_x reductions as high as 73% were measured at gas heat inputs of 18 to 19%. The maximum NO_x reductions achieved with adequate fuel burnout were 67% at full load and 73% at mid load.

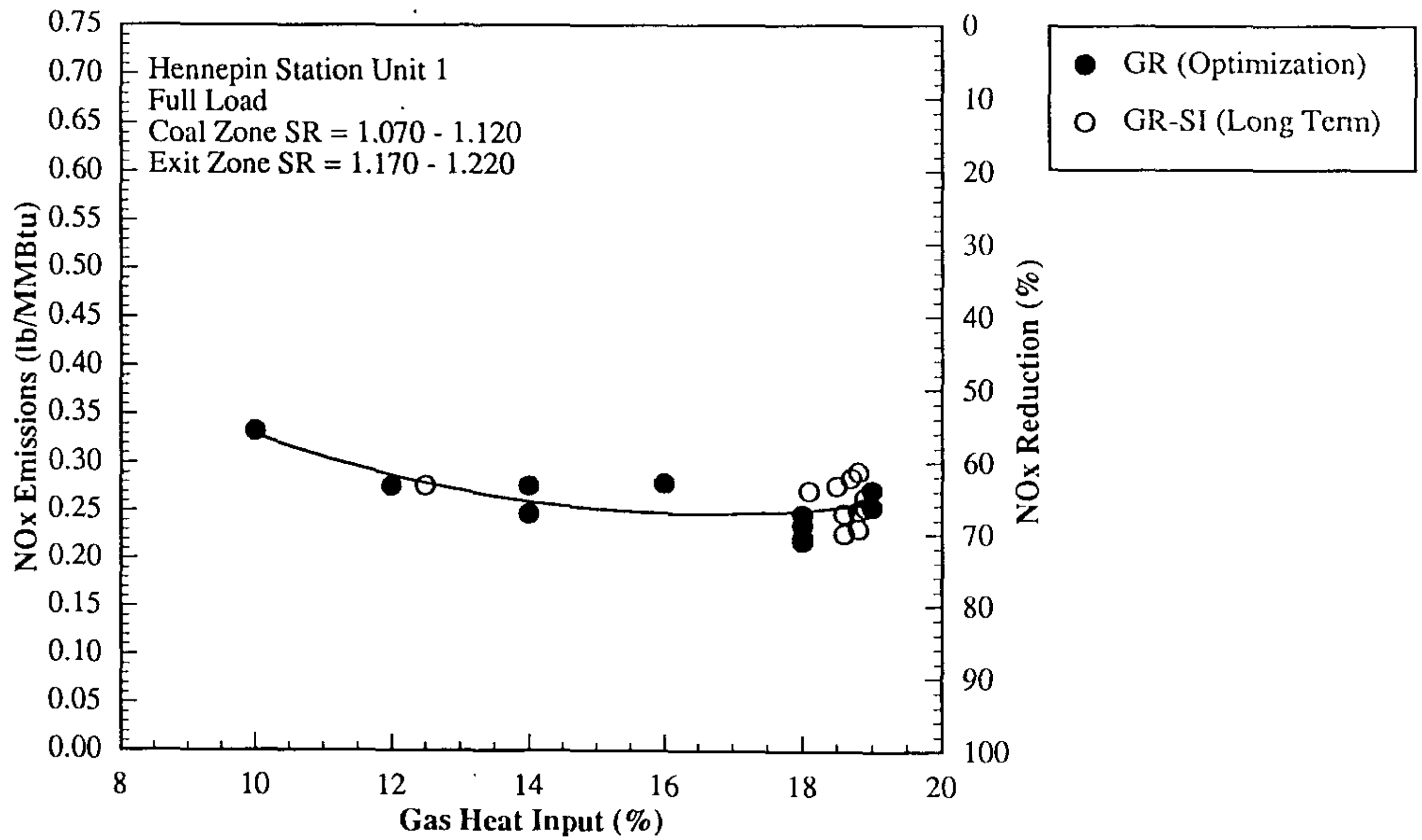


Figure 5-1. Long-Term and Optimization Testing NO_x emissions as a function of gas heat.

5.1.2.1.2 Furnace Zone Stoichiometric Ratios

The stoichiometric ratios of the three zones significantly impact the NO_x control process. Limiting the coal zone stoichiometric ratio limits the formation of NO_x in this high temperature zone. Low coal zone stoichiometric ratio also results in a reduction in the O_2 level in the reburning zone, and therefore lower reburning zone stoichiometric ratios. The impacts of coal and reburning zone stoichiometric ratios at full load are shown in Figures 5-2 and 5-3. By operation of the primary zone with excess air levels between 6 and 10 percent, and the reburning at a stoichiometric ratio between 0.87 and 0.93, NO_x emissions were maintained below 0.3 lb/10^6 Btu.

The impact of excess air is shown in Figure 5-4, utilizing baseline and staged data from the optimization and long-term GR-SI results. A significant reduction in NO_x emissions is evident with reduction in excess air during baseline operation. A more moderate effect is evident during staged operation and during GR operation with varied burnout zone SR. The impact of burnout zone stoichiometric ratio at full load is more difficult to quantify, since the majority of full-load tests were carried out with a burnout zone stoichiometric ratio in the narrow range of 1.180 to 1.220. The long-term NO_x data show a dependence on burnout zone stoichiometric ratio (which varies with OFA and SI air). At full load, the OFA input during long-term testing was generally in a narrow range: 35,000 scfm (16.5 Nm^3/s) to 37,000 scfm (17.5 Nm^3/s).

5.1.2.1.3 Burner Tilt

As indicated in Figure 5-2, the long term and optimization data are generally comparable, but long-term GR-SI NO_x emissions were impacted by coal burner tilt angles above +15 degrees. It should be noted, during the optimization test the coal burners and injectors tilted together. The burner tilt angles at full load were maintained below the horizontal position during GR operation but were automatically shifted upward during GR-SI operation to maintain reheat steam temperature. High

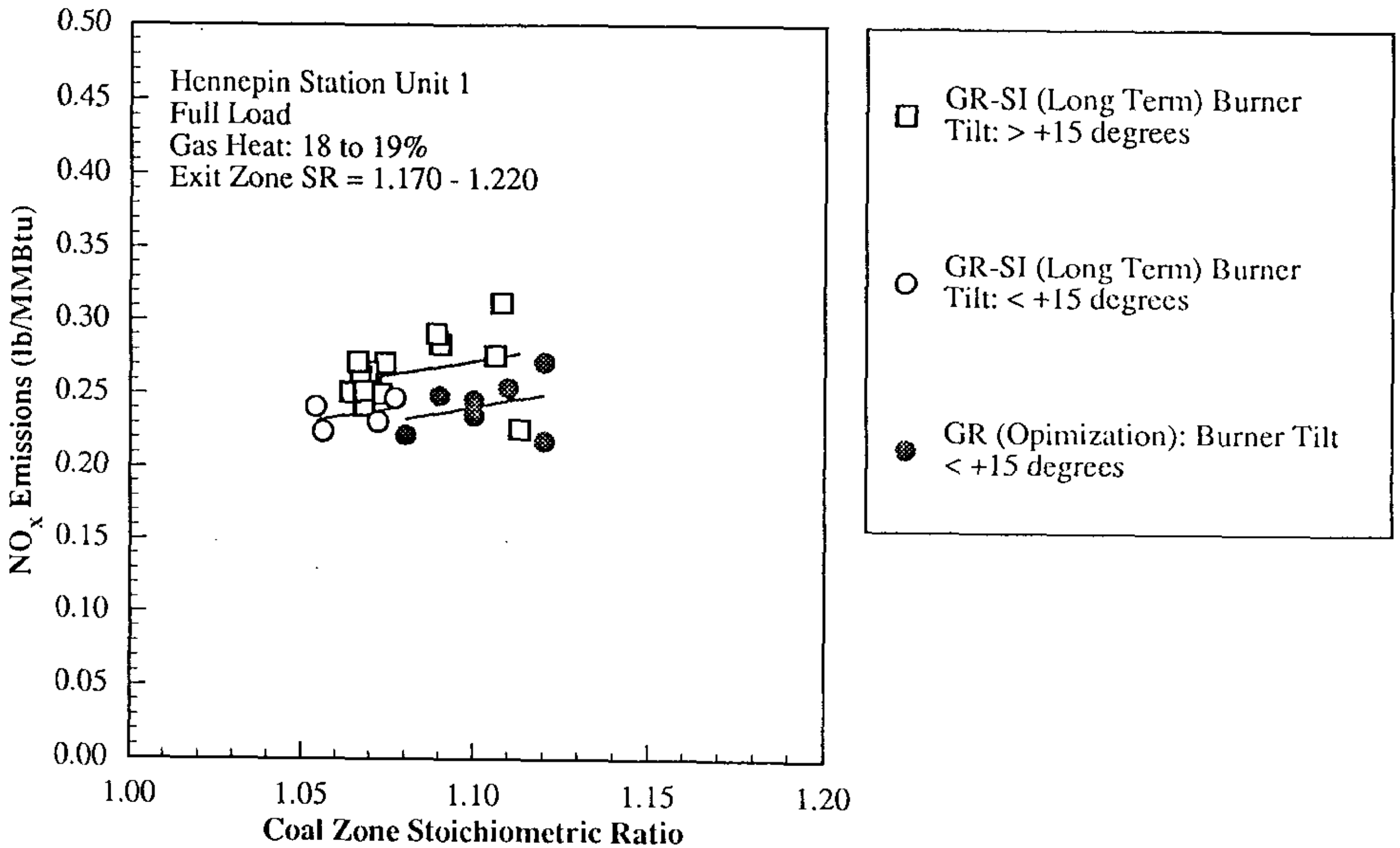


Figure 5-2. Long-Term and Optimization Testing NO_x emissions as a function of coal zone stoichiometric ratio.

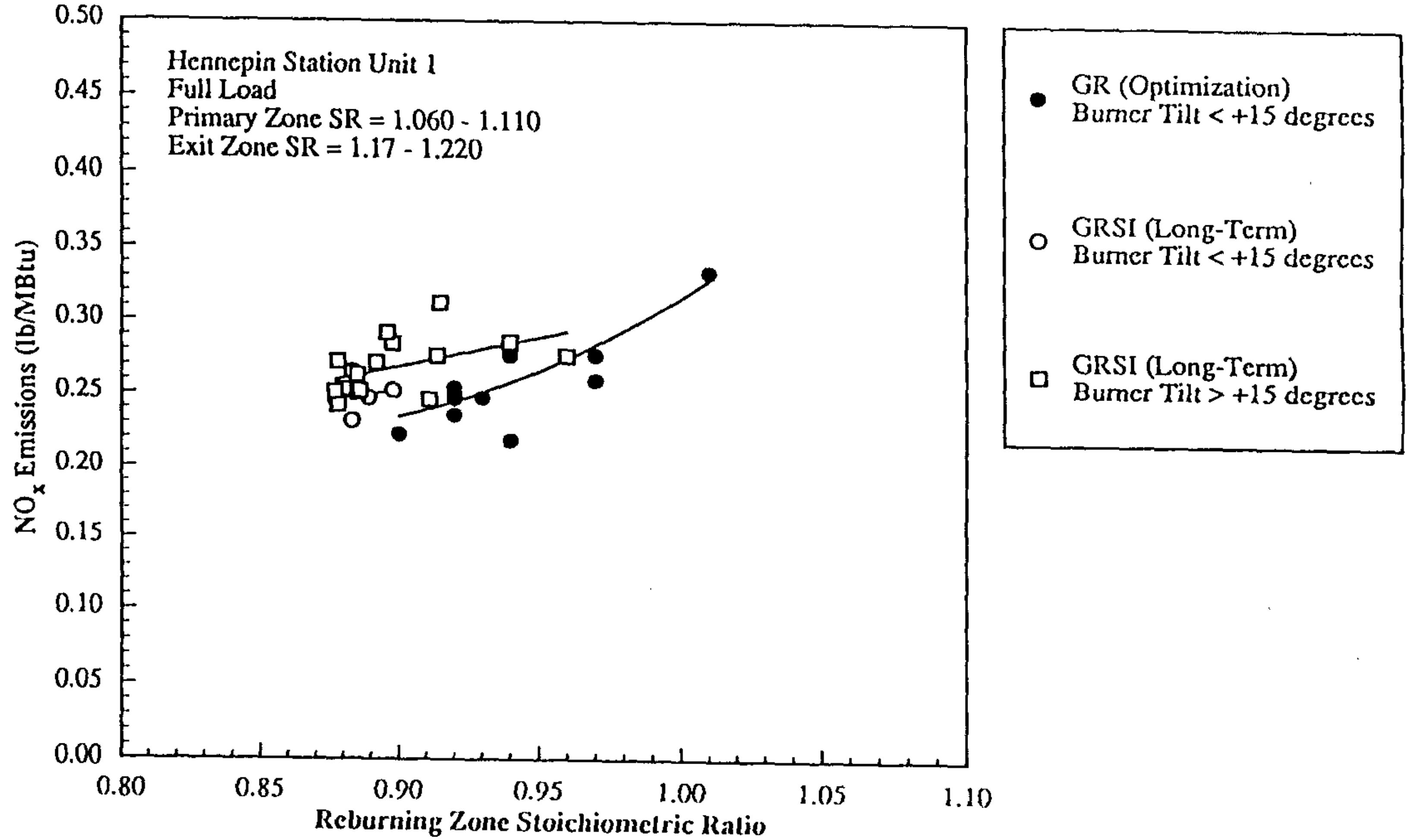


Figure5-3. Long-Term and Optimization Testing NO_x emissions as a function of reburning zone stoichiometric ratio

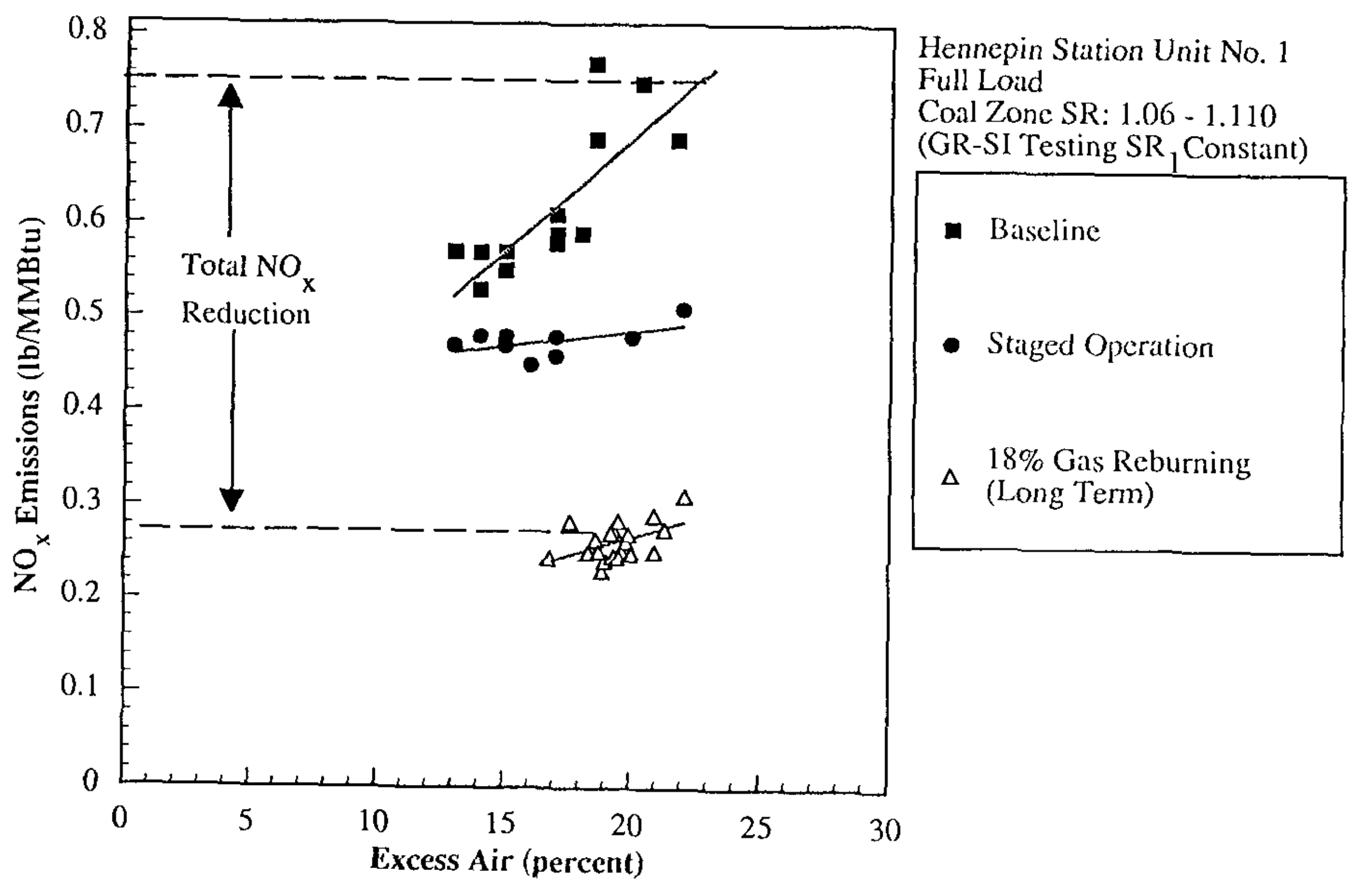


Figure 5-4. Long Term NO_x reduction as a function of excess air.

burner tilt angles potentially result in incomplete combustion of coal in the burner zone and higher oxygen concentrations into the reburning zone.

The impact of the burner tilt angle on full load NO_x emissions is evident in the following select results:

Date	Load (MWe)	Primary SR	Reburning SR	Exit SR	Burner Tilt (Deg)	NOx (lb/10^6Btu)
3/17/92	74	1.072	0.883	1.189	+6.1	0.231
9/21/92	72	1.065	0.877	1.168	+7.6	0.245
9/9/92	74	1.077	0.889	1.193	+11.1	0.247
8/12/92	75	1.069	0.883	1.186	+14.7	0.265
3/25/92	71	1.075	0.885	1.198	+20.4	0.263
8/17/92	73	1.066	0.878	1.192	+26.8	0.272

Relatively low NO_x emissions were recorded for operation with burner tilt angle at and below +11 degrees. Tests on 3/17/92, 9/9/92, and 9/21/92 were performed with the burner tilt angles at or below +11.1 degrees, resulting in NO_x emissions 0.231 to 0.247 lb/10^6Btu (99 to 106 mg/MJ). GR-SI operation with burner tilt above +20 degrees resulted in somewhat higher NO_x emissions with the highest NO_x level from the tests listed (0.272 lb/10^6Btu [117 mg/MJ]) occurred during a test with the highest upward burner tilt angle (+26.8 degrees). In the last case listed, primary and reburning zone stoichiometric ratios were relatively low (SR_1: 1.066, SR_2: 0.878).

5.1.2.1.4 Recirculated Flue Gas

The impacts of FGR input and mills in service on NO_x emissions were also determined. Optimization testing results showed that FGR input had a minor effect, with no significant change in NO_x emissions as the FGR input increased over 2.6% of total flue gas. During long-term testing, the average FGR flow was 2,811 scfm (1.33 Nm^3/s), with a range of 2,215 to 4,274 scfm (1.05 to 2.02 Nm^3/s). Many full-load tests were performed with FGR flows of 2,450 to 2,650 scfm (1.16 to 1.25 Nm^3/s). At full load with excess air of 20%, the total flue gas flow is approximately 160,000 scfm (76 Nm^3/s); therefore 2,500 scfm (1.18 Nm^3/s) corresponds to 1.6% of the total flue gas. The long-term testing data with this level of FGR are shown in Figure 5–5, which indicates a minor improvement in NO_x over that achieved with 1% FGR. The majority of points fall in the parametric range of 1% to 2.6% FGR.

The impact of mills in service is more significant than the FGR input. Generally, at loads below 55 MW_e, two mills are in service; i.e., either Mill A (bottom mill) or Mill C (top mill) is out of service. Usually Mill A was the last mill put on line as load increased. Taking the upper mill out of service results in greater staging of combustion and lower NO_x emissions. During GR-SI testing, the lowest NO_x emission of 0.179 lb/10^6Btu (77 mg/MJ) was measured with Mill C out of service. Testing from 8/18/92 to 8/28/92 was performed with Mill C out of service, over a load range of 51 to 63 MW_e. The measured NO_x emissions ranged from 0.179 to 0.231 lb/10^6Btu (77 to 99 mg/MJ), with an average of 0.197 lb/10^6Btu (85 mg/MJ). Figure 5–6 shows the effect of mills in service on NO_x emissions.

5.1.2.1.5 SO_2 and CO_2 Emissions

Emissions of SO_2 and CO_2 were modestly reduced in GR-only operation. This resulted from the differences in composition of coal and natural gas, since natural gas is essentially sulfur free and has a higher hydrogen/carbon ratio than coal. Figure 5-7 illustrates typical SO_2 emissions trends during GR and GR-SI operation, measured on December 13, 1991. GR tests showed a reduction in SO_2 equivalent to the gas heat input. The GR-SI test, showed an SO_2 reduction of 52.6% during operation with 18% gas heat input and a Ca/S of 1.57.

Reduction of CO_2 emissions is desirable, since CO_2 is a contributor to the greenhouse

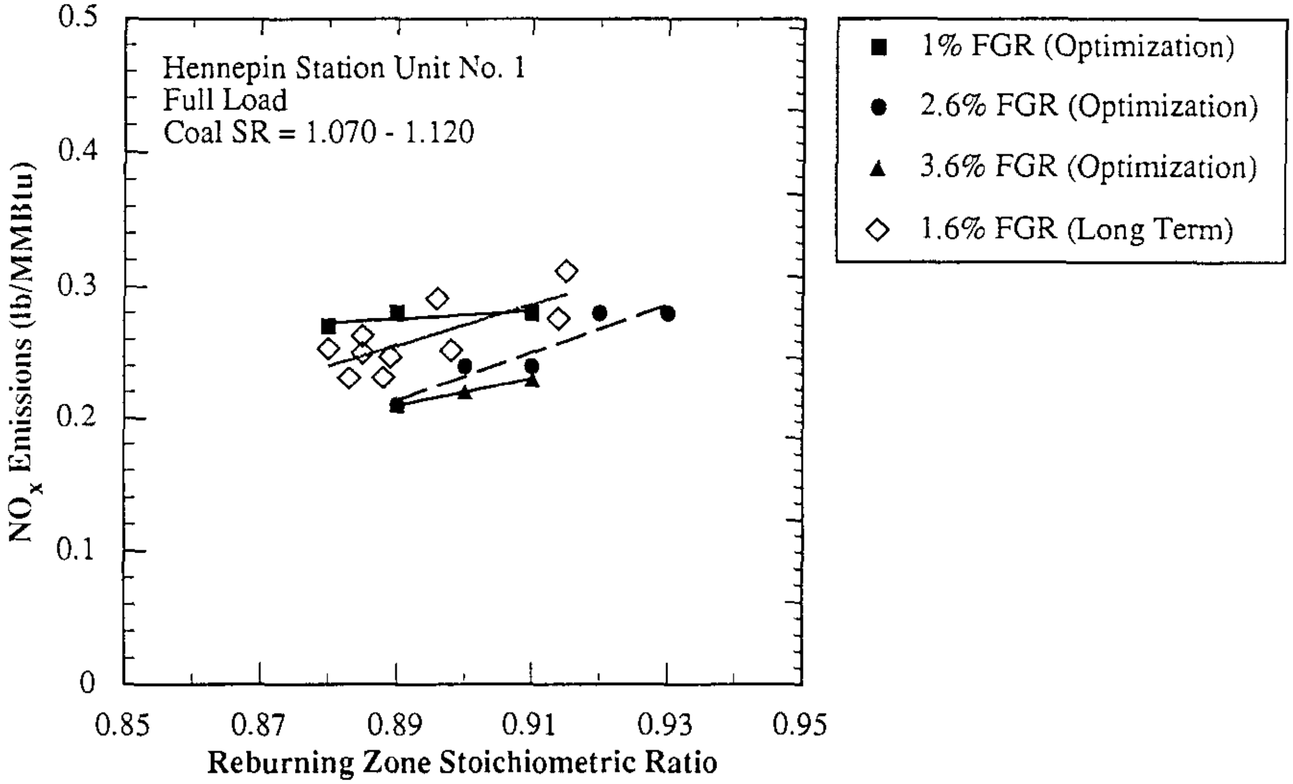


Figure 5-5. Effect of FGR on NO_x emissions during Long Term and Optimzation Testing.

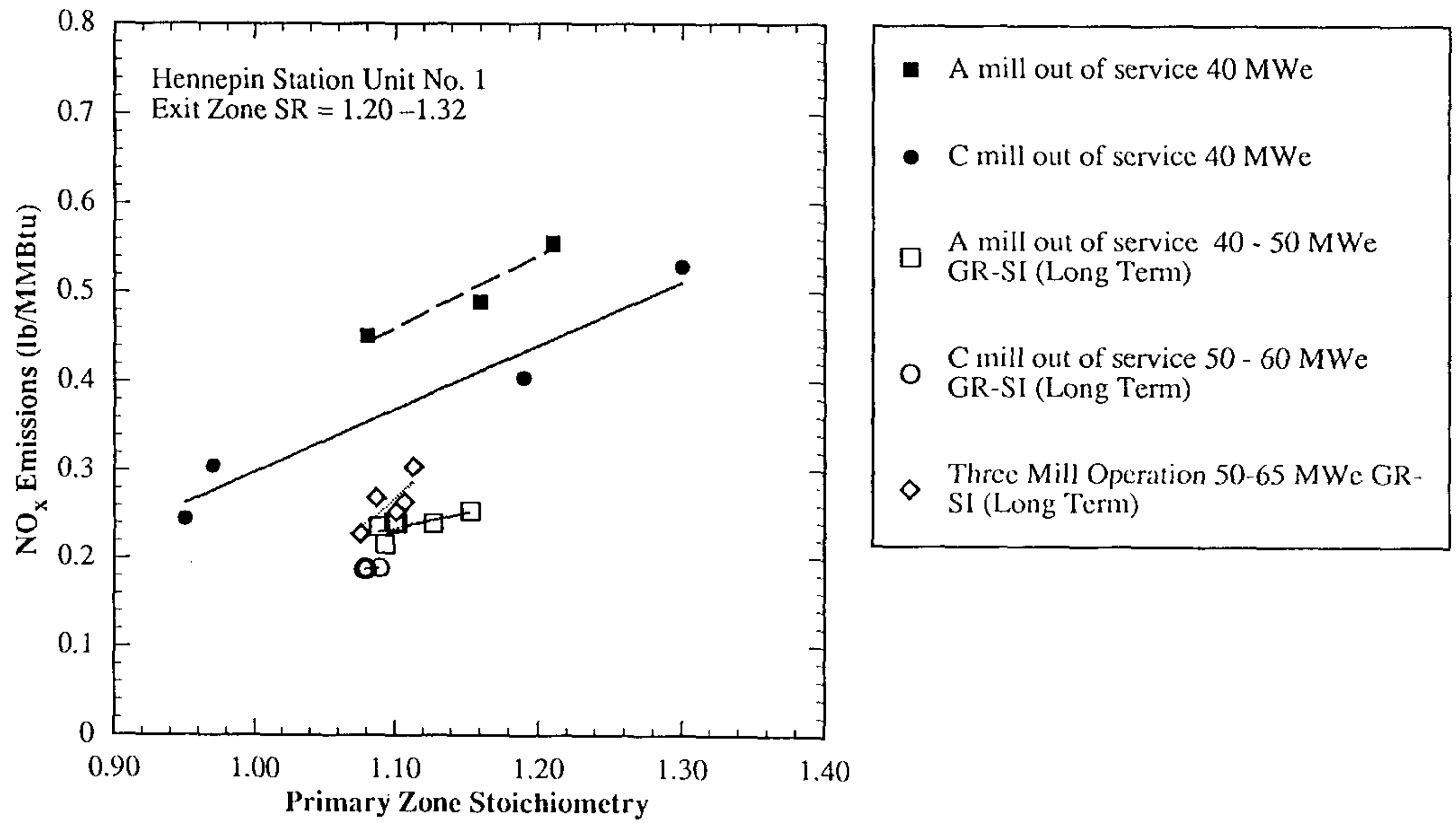


Figure 5-6. NO_x emissions as a function of mill out of service during Long Term and Optimization Testing.

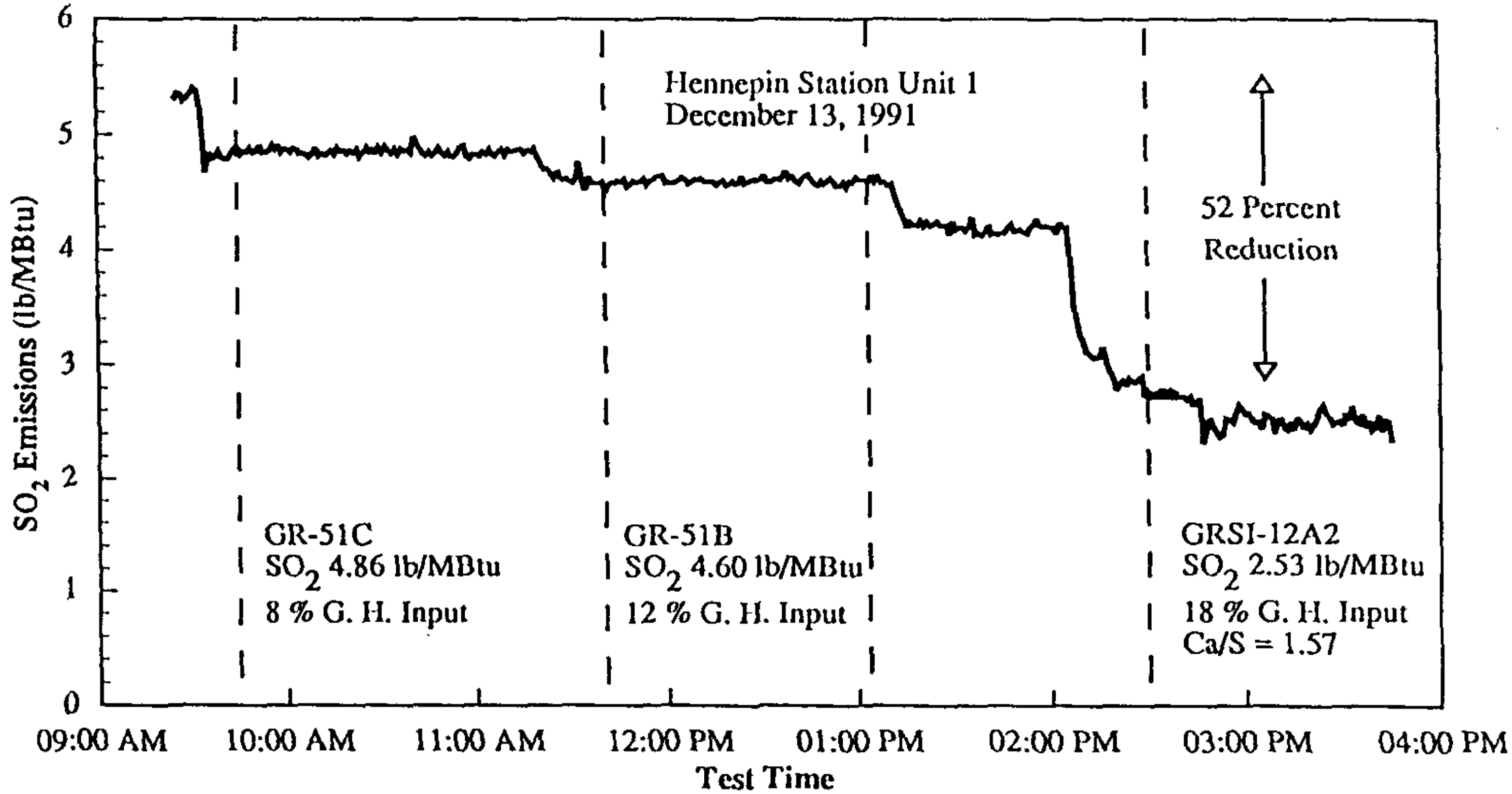


Figure 5-7. SO_2 emissions during GR and GR-SI operation

global warming effect. A modest reduction in CO_2 emissions was achieved with GR-SI. The decrease in CO_2 emissions is due to the difference in the composition (C/H) of the co-fired fuels. Combustion of the coal used in this study results in CO_2 emissions of approximately 205 lb/10^6Btu (88.2 g/MJ), which may be compared to an emissions rate of 115 lb/10^6Btu (49.5 g/MJ) from natural gas firing. Therefore, GR with natural gas at 18% of the heat input theoretically results in CO_2 emissions of 189 lb/10^6Btu (81.3 g/MJ). The CO_2 emissions are shown as a function of percent gas heat input in Figure 5-8. The small difference in measured and expected emissions reduction is due to CO emissions and ash carbon loss. Over the long-term demonstration, CO_2 emissions averaged 14.5%, which is a reduction of 7.1% from the coal baseline of 15.6%. CO_2 emissions were as low as 14.0% (@ 3% O_2) while firing approximately 20% natural gas, which corresponds to 180 lb/10^6Btu (77.4 g/MJ).

5.1.3 Sorbent Injection Results

The performance of the SI system was initially evaluated with parametric SI-only tests. This was followed by a co-application of both GR and SI technologies over the long-term testing period. The parameters which impact SO_2 capture in SI are the Ca/S molar ratio, the injection configuration, sorbent reactivity, and boiler operational impacts. Sorbent characteristics such as type (hydrate or carbonate) and fineness also impact SO_2 capture. Linwood hydrated lime was the baseline sorbent during the long-term GR-SI evaluation. In addition, three promoted sorbents, two prepared by EER (PromiSORB™ A, and PromiSORB™ B) and one High Surface Area Hydrated Lime (HSAHL) sorbent, provided by the Illinois State Geological Survey (ISGS), were tested at the conclusion of the field test. <u>Appendix D presents results of the alternate sorbents test.</u>

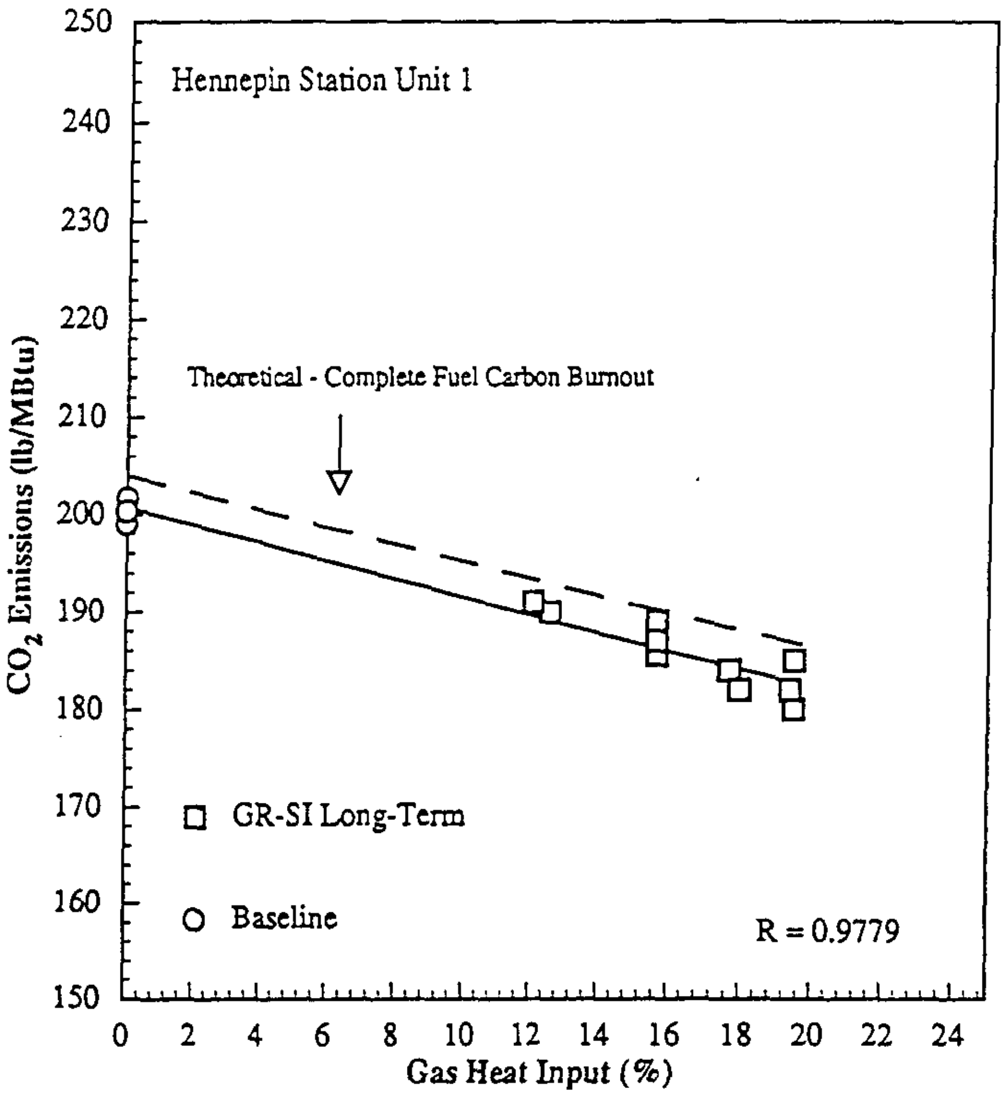


Figure 5-8. Long-Term CO_2 emissions as a function of gas heat input

5.1.3.1 SO_2 Control

FSI has been developed for SO_2 reductions in the 25 to 50% range. When combined with GR, higher SO_2 reductions can occur due to replacement of sulfur-bearing coal. Limited SI-only testing was characterized to optimize the process. The process was evaluated over full load with Ca/S molar ratios from 1.0 to 2.0. The average sorbent input rate was 5,620 lb/hr (0.71 kg/s). Reductions in SO_2 were calculated from 5.3 lb/10^6Btu (2,280 mg/MJ) baseline.

5.1.3.1.1 Ca/S Molar Ratio

Reductions in SO_2 emissions beyond the 50% reduction target level of 2.65 lb/10^6Btu (1,140 mg/MJ) were consistently obtained with Linwood hydrated lime at Ca/S molar ratios of 1.6 to 1.9. Fuel switching, i.e. reburning with natural gas at 18% heat input, theoretically reduces SO_2 emissions to the "GR–Baseline SO_2 emissions" of 4.34 lb/10^6Btu (1,870 mg/MJ). Because of a small drop in thermal efficiency during GR-SI operation, the reduction is not exactly this amount. A slightly higher total heat input is required during GR-SI. Reaction of SO_2 with sorbent then resulted in a reduction in SO_2 emissions, to an average of 2.51 lb/10^6Btu (1,080 mg/MJ). The Ca/S range evaluated during the long-term testing was relatively narrow; therefore the change in SO_2 emissions with Ca/S was minor. Tests at low loads were run generally at somewhat lower Ca/S molar ratios than high load tests. Table 5–3 lists several parameters relating to SO_2 reduction and calcium utilization. The average sorbent input rate was 5,620 lb/hr (0.71 kg/s), achieving a Ca/S molar ratio of 1.76 at an average load of 62 MW_e. The average SO_2 reduction over all of the GR–SI tests was 52.6%. The SO_2 reduction due to reaction with sorbent, termed "sorbent SO_2 reduction", averaged 42.1%, which corresponds to a calcium utilization of 24.1%.

The sorbent SO_2 reduction showed considerable variation during both the optimization and long–term GR-SI testing. This is due to variations in sorbent purity, ash

TABLE 5-3. GR-SI SORBENT INJECTION AVERAGE DAILY PERFORMANCE DATA

Date 1992	Avg. Load (MWe)	Gas Heat (%)	Sorb Flow (klb/hr)	Ca/S (mole/mole)	SO_2 Emiss. (lb/MBtu)	GR-SO_2 Bsln (lb/MBtu)	SO_2 Red Tot (%)	SO_2 Red Sorb (%)	Ca Utiliz. (%)
Jan-10	55	15.7	4.96	1.75	2.289	4.468	56.81	48.77	27.87
Jan-13	57	17.7	5.11	1.76	2.337	4.362	55.91	46.42	26.38
Jan-21	52	18.0	4.77	1.78	2.423	4.346	54.28	44.25	24.86
Jan-22	46	19.5	4.14	1.77	2.470	4.267	53.40	42.11	23.79
Jan-23	52	19.7	4.87	1.85	2.333	4.256	55.98	45.18	24.42
Jan-27	46	19.3	4.23	1.77	2.641	4.277	50.17	38.25	21.61
Jan-28	52	19.4	4.75	1.77	2.663	4.272	49.75	37.66	21.28
Jan-29	61	19.5	5.82	1.89	2.839	4.267	46.43	33.46	17.70
Jan-30	51	18.5	4.94	1.88	2.737	4.320	48.36	36.64	19.49
Feb-06	72	18.8	6.80	1.84	2.627	4.304	50.43	38.96	21.17
Feb-19	63	18.6	6.56	2.07	2.693	4.314	49.19	37.58	18.15
Feb-20	46	18.2	4.27	1.79	2.347	4.335	55.72	45.86	25.62
Feb-21	58	18.5	5.58	1.82	2.445	4.320	53.87	43.40	23.84
Feb-24	46	18.7	4.31	1.81	2.590	4.309	51.13	39.89	22.04
Feb-25	49	18.1	4.52	1.78	2.390	4.341	54.91	44.94	25.25
Feb-26	69	18.6	6.60	1.84	2.476	4.314	53.28	42.61	23.16
Feb-28	61	18.3	5.77	1.94	2.350	4.330	55.66	45.73	23.57
Mar-02	73	18.5	6.90	1.84	2.651	4.320	49.98	38.63	20.99
Mar-03	47	18.3	4.56	1.86	2.612	4.330	50.72	39.68	21.33
Mar-04	57	18.4	5.41	1.82	2.576	4.325	51.40	40.44	22.22
Mar-10	63	18.8	5.96	1.82	2.469	4.304	53.42	42.63	23.42
Mar-11	73	18.7	5.29	1.42	2.915	4.309	45.00	32.35	22.78
Mar-12	59	18.5	5.08	1.66	2.592	4.320	51.09	39.99	24.09
Mar-13	67	18.6	6.44	1.86	2.427	4.314	54.21	43.74	23.52
Mar-16	65	18.6	6.10	1.83	2.395	4.314	54.81	44.49	24.31
Mar-17	74	18.8	6.83	1.82	2.555	4.304	51.79	40.63	22.32
Mar-19	74	18.9	7.23	1.90	2.485	4.298	53.11	42.19	22.20
Mar-23	44	18.5	4.16	1.84	2.498	4.320	52.87	42.17	22.92
Mar-24	61	18.8	5.89	1.82	2.551	4.304	51.87	40.72	22.38
Mar-25	71	18.9	6.76	1.86	2.395	4.298	54.81	44.28	23.81
Mar-26	74	18.8	6.69	1.76	2.649	4.304	50.02	38.45	21.84
Apr-02	74	18.1	6.45	1.72	2.443	4.341	53.91	43.72	25.42
Apr-03	75	12.8	7.91	1.87	2.871	4.622	45.83	37.88	20.26
Apr-06	63	12.6	6.98	2.01	2.484	4.632	53.13	46.38	23.07
Apr-07	62	12.1	5.24	1.54	2.700	4.659	49.06	42.04	27.30
Apr-08	74	12.5	6.80	1.68	2.569	4.638	51.53	44.60	26.55
Apr-09	74	15.7	7.35	1.87	2.222	4.468	58.08	50.27	26.88
Apr-10	56	15.7	4.74	1.58	2.569	4.468	51.53	42.50	26.90
Apr-13	74	19.0	7.14	1.87	2.738	4.293	48.34	36.22	19.37
Apr-14	62	18.7	5.90	1.82	2.544	4.309	52.00	40.96	22.51
Apr-16	47	18.3	4.38	1.79	2.422	4.330	54.30	44.07	24.62
Apr-21	71	18.7	6.53	1.79	2.320	4.309	56.23	46.16	25.79
Apr-22	64	18.7	6.04	1.82	2.321	4.309	56.21	46.13	25.35
Apr-23	67	18.9	6.29	1.83	2.368	4.298	55.32	44.91	24.54

TABLE 5-3. GR-SI SORBENT INJECTION AVERAGE DAILY PERFORMANCE DATA (Cont.)

Date 1992	Avg. Load (MWe)	Gas Heat (%)	Sorb Flow (klb/hr)	Ca/S (mole/mole)	SO_2 Emiss. (lb/MBtu)	GR–SO_2 Bsln (lb/MBtu)	SO_2 Red Tot (%)	SO_2 Red Sorb (%)	Ca Utiliz. (%)
Jul-29	61	18.5	5.34	1.70	2.733	4.320	48.43	36.73	21.61
Jul-30	49	18.2	4.23	1.66	2.531	4.335	52.25	41.62	25.07
Jul-31	45	18.4	3.92	1.69	2.599	4.325	50.96	39.90	23.61
Aug-03	46	18.2	4.03	1.67	2.731	4.335	48.47	37.01	22.16
Aug-05	64	18.4	5.63	1.71	2.775	4.325	47.64	35.84	20.96
Aug-11	75	18.8	6.95	1.79	2.737	4.304	48.36	36.40	20.34
Aug-12	75	18.7	6.87	1.78	2.728	4.309	48.53	36.69	20.61
Aug-13	74	18.6	6.55	1.73	2.779	4.314	47.57	35.58	20.57
Aug-14	75	18.8	6.92	1.78	3.042	4.304	42.60	29.31	16.47
Aug-17	73	18.9	6.18	1.70	2.459	4.298	53.60	42.79	25.17
Aug-18	58	18.7	4.92	1.63	2.414	4.309	54.45	43.98	26.98
Aug-19	62	18.5	5.14	1.63	2.706	4.320	48.94	37.35	22.92
Aug-20	51	18.9	4.39	1.66	2.239	4.298	57.75	47.91	28.86
Aug-21	56	18.5	4.78	1.64	2.376	4.320	55.17	44.99	27.44
Aug-24	54	18.9	4.76	1.69	2.666	4.298	49.70	37.98	22.47
Aug-25	54	18.6	4.62	1.65	2.499	4.314	52.85	42.08	25.50
Aug-26	47	18.7	4.04	1.66	2.287	4.309	56.85	46.92	28.27
Aug-27	62	18.6	5.27	1.64	2.014	4.314	62.00	53.32	32.51
Aug-28	63	18.5	5.62	1.68	2.888	4.320	45.51	33.14	19.73
Sep-02	73	18.7	6.36	1.71	2.210	4.309	58.30	48.71	28.49
Sep-09	74	18.6	6.12	1.61	2.483	4.314	53.15	42.45	26.36
Sep-10	75	18.7	6.44	1.64	2.452	4.309	53.74	43.09	26.28
Sep-11	74	18.6	6.54	1.71	2.606	4.314	50.83	39.59	23.15
Sep-16	72	18.8	6.31	1.70	2.194	4.304	58.60	49.02	28.83
Sep-21	72	18.9	6.34	1.69	2.340	4.298	55.85	45.56	26.96
Sep-22	50	18.5	4.39	1.68	2.129	4.320	59.83	50.71	30.19
Sep-23	50	18.5	4.39	1.69	2.171	4.320	59.04	49.74	29.43
Sep-24	51	18.5	4.51	1.70	2.232	4.320	57.89	48.33	28.43
Sep-30	58	18.6	5.07	1.68	2.171	4.314	59.04	49.68	29.57
Oct-12	57	18.0	4.98	1.70	2.525	4.346	52.36	41.90	24.65
Oct-19	72	18.2	6.50	1.73	2.506	4.335	52.72	42.20	24.39
Average	62	18.2	5.62	1.76	2.510	4.336	52.65	42.11	24.06
Maximum	75	19.7	7.91	2.07	3.042	4.659	62.00	53.32	32.51
Minimum	44	12.1	3.92	1.42	2.014	4.256	42.60	29.31	16.47
St. Dev.	10	1.5	1.02	0.10	0.203	0.080	3.83	4.73	3.11

deposition, and gas temperatures which were affected by burner tilt angle variation. Testing was conducted near a set-point Ca/S molar ratio; therefore, the change in sorbent SO_2 reduction with Ca/S molar ratio was minor. The maximum sorbent SO_2 reduction of 53.3% was obtained for a test conducted with a Ca/S molar ratio of 1.64. This SO_2 reduction corresponds to the maximum calcium utilization of 32.5%. The lowest sorbent SO_2 reduction of 29.3% was measured for a full load test at a Ca/S molar ratio of 1.78. The sorbent SO_2 removals were in the range determined during optimization testing. The majority of sorbent SO_2 removals with Linwood hydrate were in the 35 to 50% range for Ca/S molar ratios of 1.60 to 1.90. Figure 5-9 shows the sorbent SO_2 removals over several load ranges and the full load model prediction for 100% pure sorbent and an adjusted prediction based on a purity of 96.2%. These lines indicate the significant impact of sorbent purity and show that when purity is taken into account the results agree with or exceed model predictions.

The calcium utilization was found to depend most strongly on the Ca/S molar ratio. The sorbent utilization varied by approximately 8% at each Ca/S molar ratio and no significant load effect was determined. As expected, sorbent utilization drops off with Ca/S molar levels due to diffusion limitations as more sorbent is injected. Figure 5-10 shows the calcium utilization as a function of Ca/S molar ratio. A drop in utilization of approximately 5% over the Ca/S molar ratio increase from 1.6 to 1.9 is evident. A small reduction in sorbent utilization with load is evident in some cases and is most likely due to elevated temperature and reduced residence time in the optimal temperature window. This result was also evident from the optimization testing data. During the long-term testing period, limited SI only testing was conducted. The following table presents the trend of SO_2 reduction.

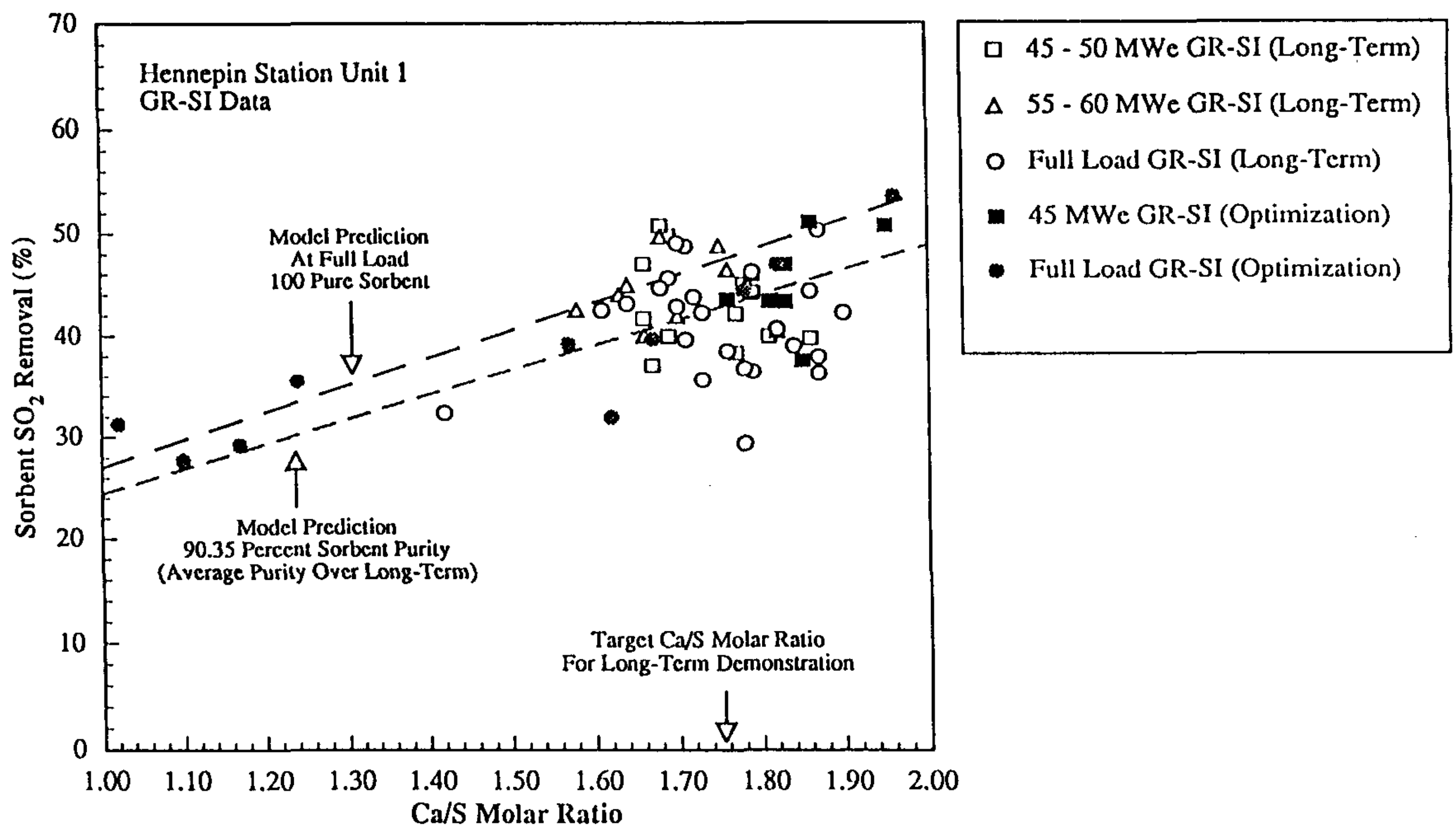


Figure 5-9. Long-Term and Optimization Testing sorbent SO_2 removal as a function of Ca/S molar ratio

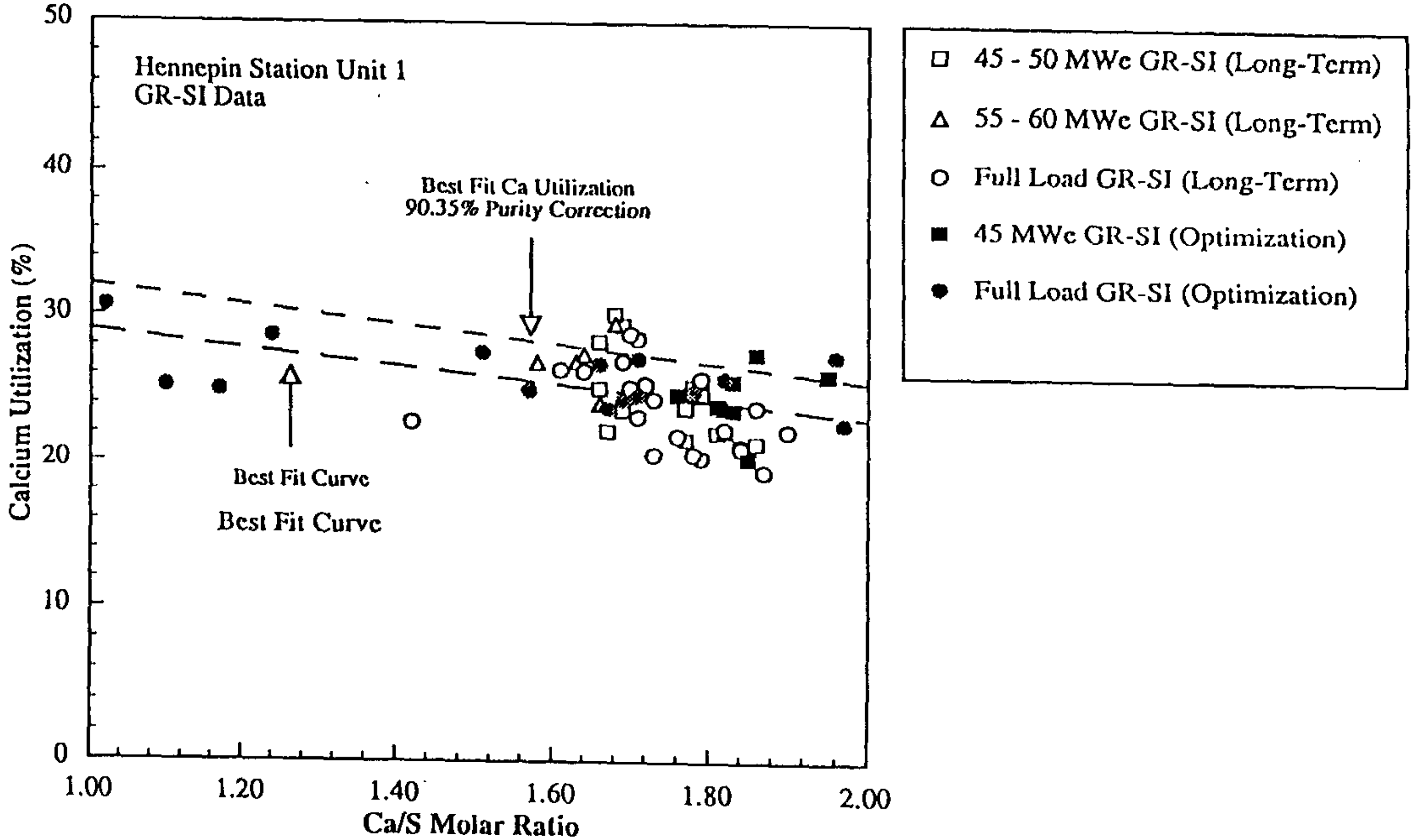


Figure 5–10. Long-Term and Optimization Testing calcium utilization as a function of Ca/S molar ratio

Load (MWe)	Ca/S (mole/mole)	SO_2 Emissions (lb/10^6Btu)	SO_2 Removal (%)	Calcium Utilization (%)
73	1.82	3.260	38.49	21.15
70	1.84	3.394	35.96	19.55
44	1.79	3.292	37.89	21.17

These SO_2 removals are in the lower range for sorbent SO_2 removals calculated from GR-SI operation. The calcium utilizations are also several percent (approximately 3%) below the GR-SI utilizations. The limited SI tests conducted during the year-long demonstration indicate that GR in addition to SI, not withstanding the SO_2 reduction brought about by use of sulfur free natural gas, appears to have a minor positive impact on sorbent sulfation. SI, without GR, had calcium utilizations in the lower range of GR-SI utilizations.

5.1.3.1.2 Injection Configuration

Computational models accounted for sorbent dispersion in the furnace to generate a more general prediction of SO_2 capture efficiencies. In these studies, sorbent dispersion and SO_2 concentrations were shown to have a significant effect on sorbent SO_2 capture efficiencies. Sorbent dispersion is dependent on the penetration and coverage characteristics of the sorbent stream and can be altered by varying the SI velocity and the injection configuration.

The SI injection system was designed with 6 jets to mix the sorbent uniformly across the furnace (4 on the front wall and 2 on the side walls). Figure 5-11 compares the performance in this configuration with that measured when the 2 side wall jets were out of service. As expected, calcium utilization degraded significantly with these jets out of service.

As shown above, the SO_2 removal goal of the project was consistently achieved at full

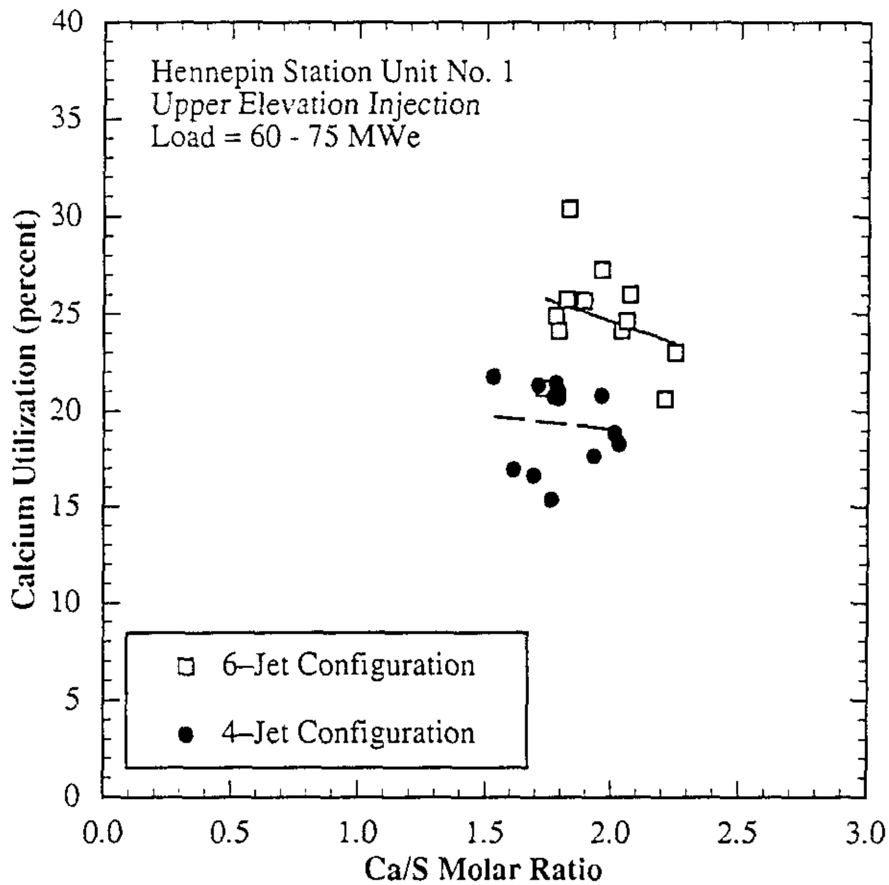


Figure 5-11. Effect of Ca/S on two upper injection configurations at full load

load using the upper level sorbent injectors. The SI system included a lower set of injectors at the OFA ports for low loads (< 45 MW_e) where furnace temperature decreased. Figure 5-12 compares the calcium utilization using the upper and lower injectors over the load range. Surprisingly, sorbent utilization was constant over the load range for injection of sorbent from both locations.

5.1.3.1.3 Burner Tilt

Tests at various burner tilt angles were conducted to evaluate the sensitivity of the temperature profile and its effect on sorbent SO_2 capture, particularly under lower load operation when burner tilt is adjusted to maintain reheat steam temperature. As shown in Figure 5–13, the mid– and full–load tests showed calcium utilization to be insensitive to burner tilt angles between -5 to +19 degrees. At low loads (45 MW_e to 58 MW_e) shown in Figure 5–14, calcium utilization was significantly affected in tests with burner tilts between -6 and +13 degrees, with lower level sorbent injectors in service. A temperature profile taken in July 1991, Figure 5–15, showed that at 45 MW_e with the burner tilts in their normal position, +20 degrees, approximately a third of the furnace, near the front wall, had temperatures exceeding 2,350°F (1288°C). As previously stated, laboratory studies have demonstrated that hydrated limes exposed to temperatures exceeding 2,350°F (1288°C) exhibit a decrease in reactivity due to a loss in surface area. Figure 5–16 demonstrates the burner tilt variation with low loads and upper level SI. Calcium utilization can be increased at lower load with the upper injectors in service, by upward shift of burner tilts.

5.1.4 GR-SI Long-Term Results

Data for long-term GR-SI demonstration was recorded from January 10, 1992 to October 19, 1992. The average load during the test period was 62 MW_e. The averages for major monitored parameters are as follows: gas heat input 18.2%, Ca/S 1.75, NO_x reduction 67.26% and SO_2 reduction 52.65%.

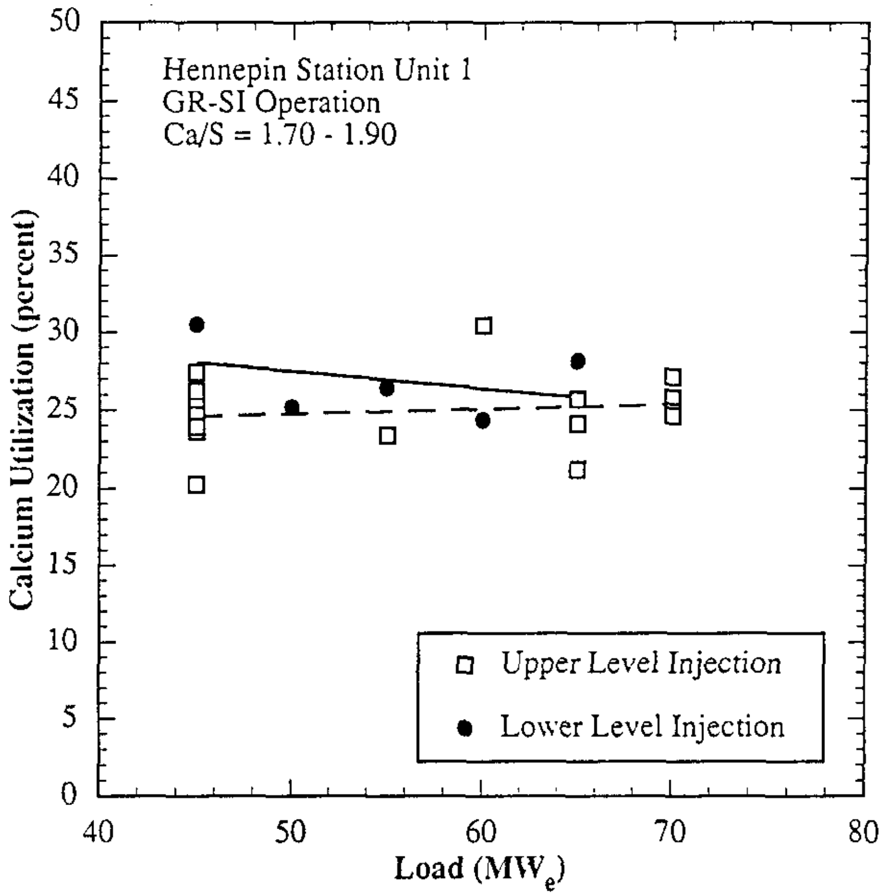


Figure 5-12. Effect of load on calcium utilization.

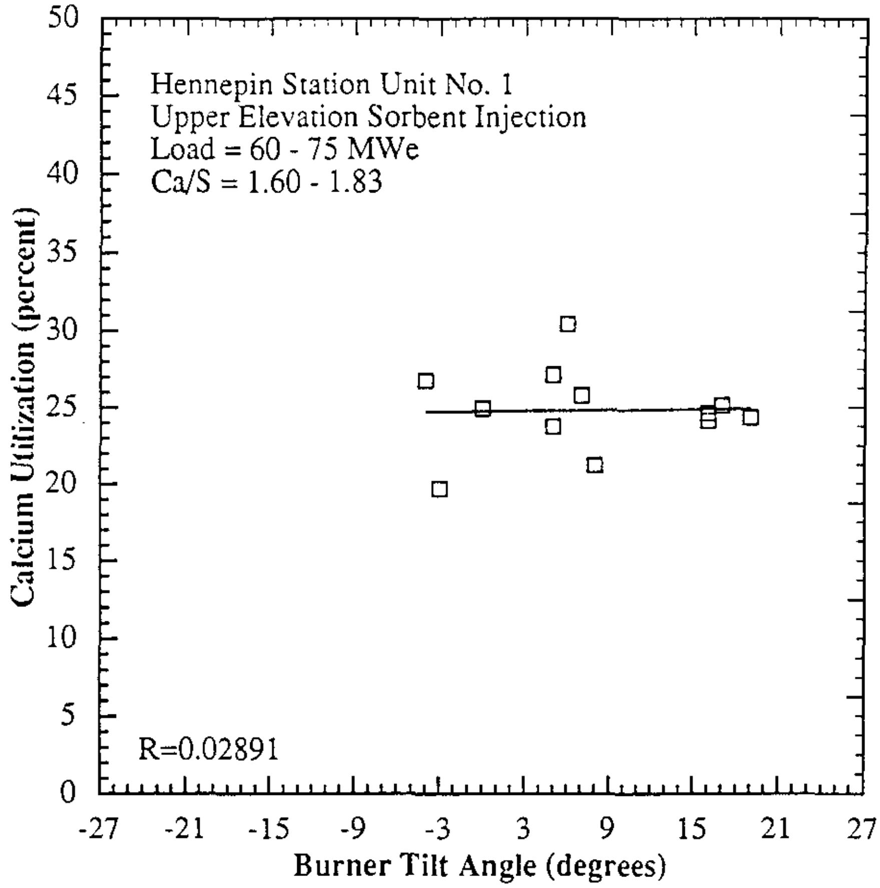


Figure 5-13. Effect of burner tilt on calcium utilization for high load cases.

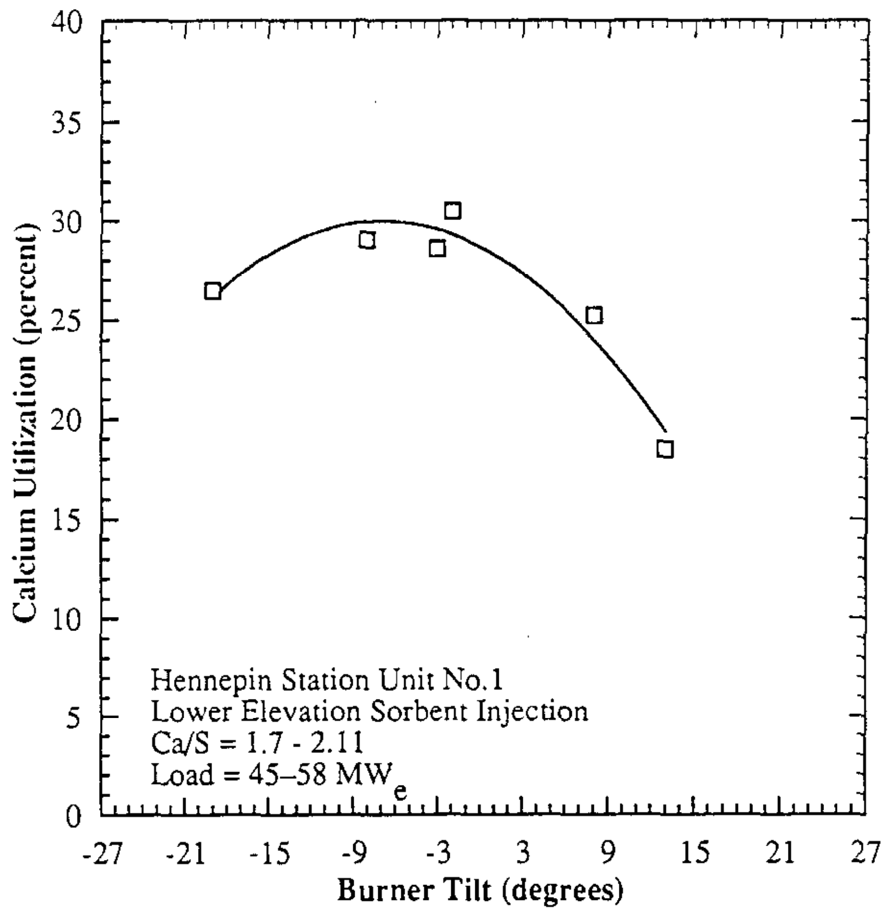
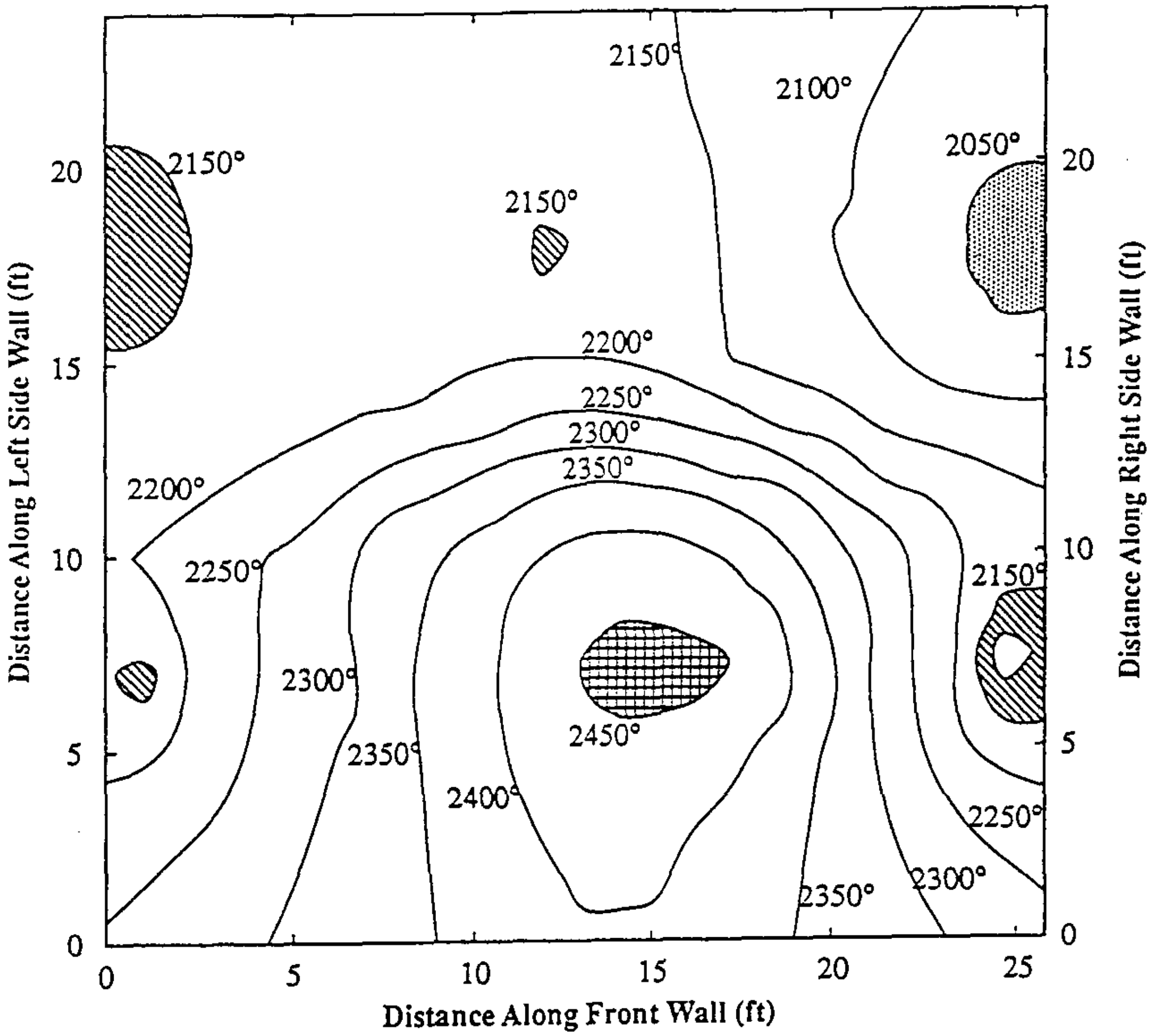


Figure 5-14. Effect of burner tilt on calcium utilization during GR-SI tests with lower injection elevation at low load.



Note : Units in °F.

Figure 5-15. Temperature variation across Plane "C" for low load Gas Geburning condition (GR-40C) with -20° burner tilt

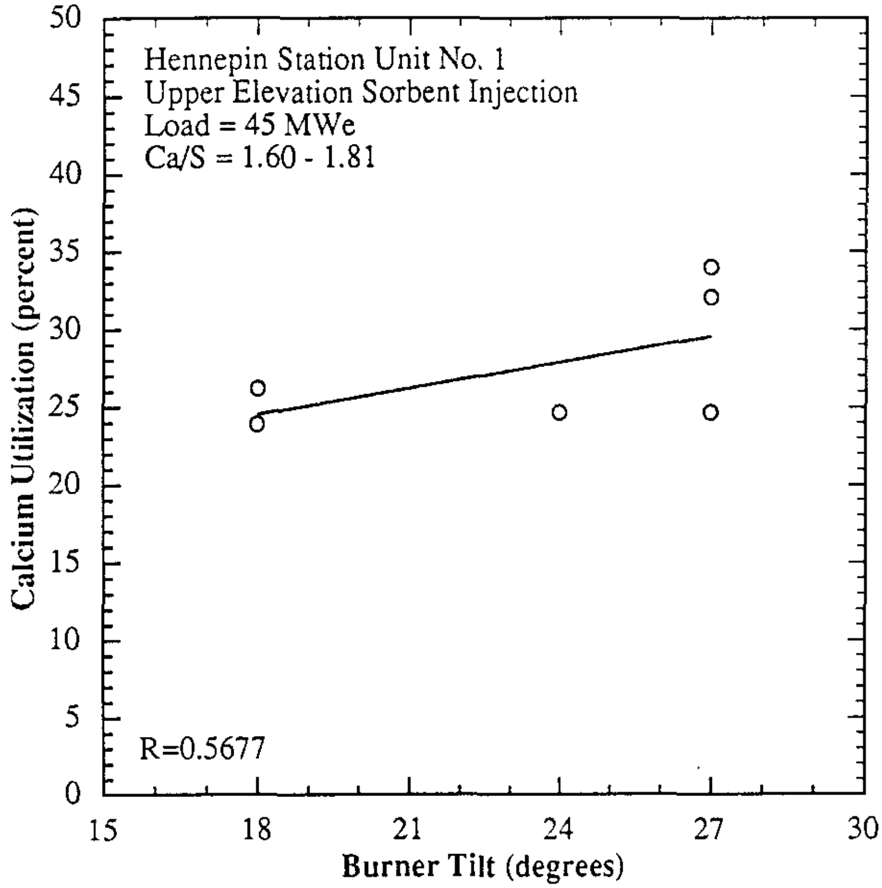


Figure 5-16. Effect of burner tilt on calcium utilization during GR-SI tests with upper elevation injection at low load.

5.1.4.1 NO_x and SO_2 Control

The NO_x and SO_2 reductions measured over this period are shown in Figure 5-17 and Tables 5-4, and 5-5. The target reductions of 60% NO_x and 50% SO_2 are also shown. Generally, gas heat inputs of 18 to 19% were used (the average was 18.2%) and Ca/S was 1.0 to 2.0. On average the Ca/S during the long-term testing period was 1.76. Over the long-term testing period, NO_x reduction averaged 67.3% and SO_2 reduction averaged 52.6% at full load.

5.1.5 Impacts of GR, SI, and GR-SI on Boiler Thermal Performance

Various thermal performance parameters were recorded or calculated by the Boiler Performance Monitoring System (BPMS), a software package developed by EER. A data base was established which included the following thermal performance parameters:

- Steam flow rate, temperature and pressure
- Steam attemperation spray
- Heat transfer to water/steam
- Gas side temperatures
- Thermal efficiency
- Heat rate

Tables 5–6, 5–7, 5–8, and 5–9 summarize the thermal performance of the unit during the long–term demonstration period for Baseline, GR, SI (45 MW_e only), and GR-SI operation, respectively. Since unit operation was generally under dispatch control, the data are summarized for low, mid, and high loads. In addition, the results were compared to heat transfer model predictions to evaluate the validity of the design methodology. The following sections describe the impacts of GR–SI on superheat and

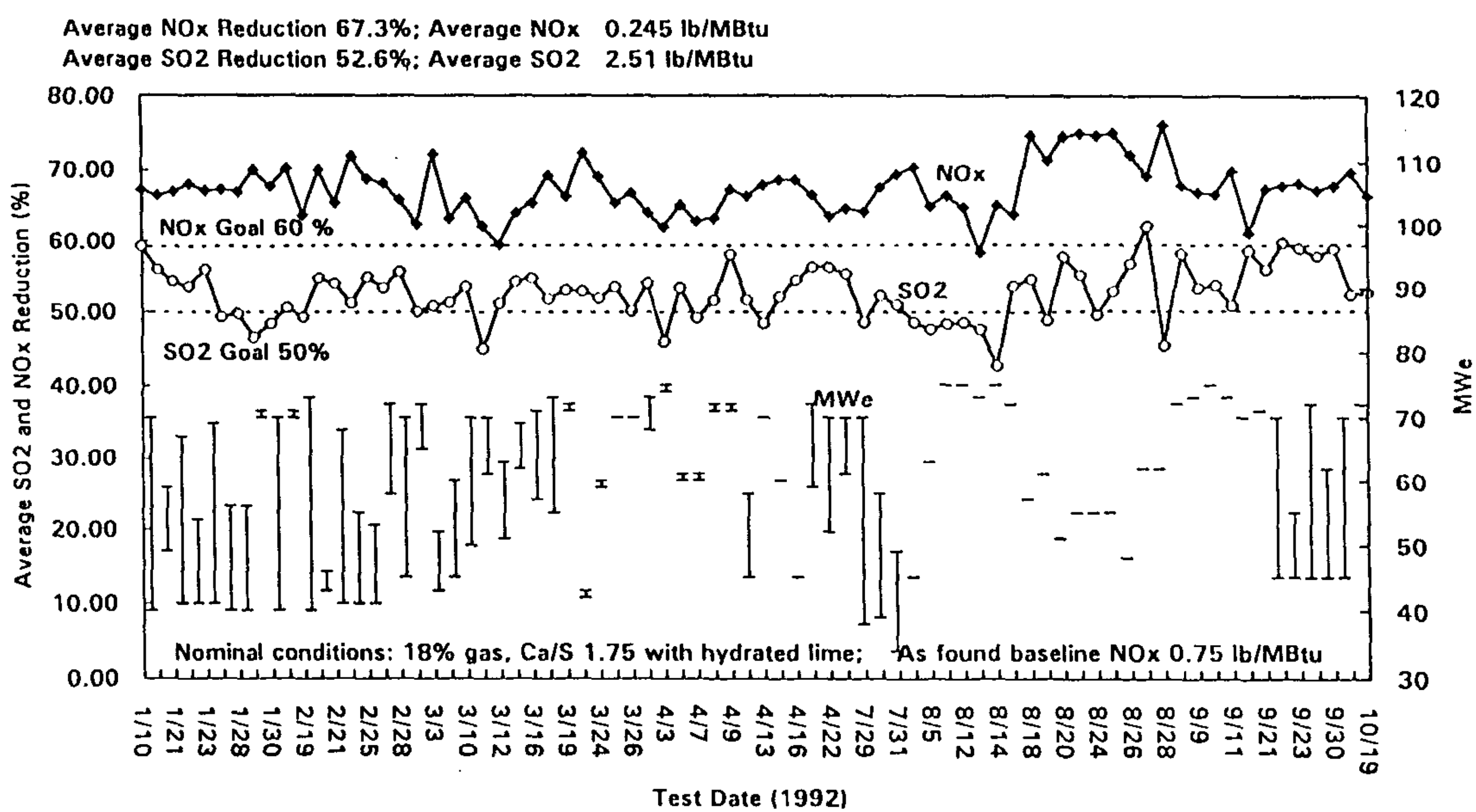


Figure 5-17. Emissions of NO_x and SO_2 from Long-Term GR-SI Testing

TABLE 5-4. LONG TERM GR-SI TESTING AVERAGE DAILY EMISSIONS

Date 1992	Avg. Load (MWe)	O_2 (%, Dry)	O_2 (%, Wet)	CO_c (ppm)	$CO_{2,c}$ (%)	HC_c (ppm)	$NO_{x,c}$ (ppm)	NO_x (lb/MBtu)	NO_x Red (%)	$SO_{2,c}$ (ppm)	SO_2 (lb/MBtu)	SO_2 Red Tot (%)
Jan-10	55	5.83	2.84	74	14.4	0.1	198	0.262	65.07	1,237	2.289	56.81
Jan-13	57	5.58	2.90	75	14.3	0.1	191	0.252	66.40	1,269	2.337	55.91
Jan-21	52	6.37	3.56	117	14.2	1.0	188	0.248	66.93	1,316	2.423	54.28
Jan-22	46	6.78	3.65	66	14.0	1.6	180	0.240	68.00	1,324	2.470	53.40
Jan-23	52	6.43	3.27	150	14.2	2.2	185	0.247	67.07	1,250	2.333	55.98
Jan-27	46	6.67	3.70	65	14.3	2.0	190	0.254	66.13	1,415	2.641	50.17
Jan-28	52	6.25	3.37	58	14.2	3.6	186	0.248	66.93	1,427	2.663	49.75
Jan-29	61	6.00	2.81	69	14.4	2.1	169	0.226	69.87	1,521	2.839	46.43
Jan-30	51	6.12	3.07	164	14.3	3.3	182	0.243	67.60	1,465	2.737	48.36
Feb-06	72	5.97	2.79	18	14.4	0.1	168	0.224	70.13	1,407	2.627	50.43
Feb-19	63	5.93	3.10	32	14.6	2.4	204	0.273	63.60	1,441	2.693	49.19
Feb-20	46	6.38	3.32	196	14.3	1.8	162	0.216	71.20	1,256	2.347	55.72
Feb-21	58	6.22	3.27	109	14.3	1.8	194	0.260	65.33	1,309	2.445	53.87
Feb-24	46	6.32	3.40	166	14.4	1.4	158	0.211	71.87	1,386	2.590	51.13
Feb-25	49	6.66	3.51	93	14.4	1.3	186	0.249	66.80	1,278	2.390	54.91
Feb-26	69	5.56	2.68	43	14.3	1.3	179	0.239	68.13	1,325	2.476	53.28
Feb-28	61	6.24	3.22	28	14.5	1.1	192	0.256	65.87	1,258	2.350	55.66
Mar-02	73	5.78	2.84	20	14.5	1.0	206	0.276	63.20	1,419	2.651	49.98
Mar-03	47	6.51	3.74	179	14.4	4.1	157	0.209	72.13	1,398	2.612	50.72
Mar-04	57	6.16	3.06	84	14.4	1.5	207	0.276	63.20	1,378	2.576	51.40
Mar-10	63	5.67	2.84	29	14.5	2.5	191	0.255	66.00	1,322	2.469	53.42
Mar-11	73	5.71	2.72	31	14.3	2.3	213	0.284	62.13	1,565	2.915	45.00
Mar-12	59	6.14	3.04	22	14.4	1.8	228	0.304	59.47	1,387	2.592	51.09
Mar-13	67	6.36	3.08	41	14.1	2.1	202	0.270	64.00	1,299	2.427	54.21
Mar-16	65	5.87	3.05	30	14.3	1.2	195	0.260	65.33	1,282	2.395	54.81
Mar-17	74	5.70	2.78	13	14.6	2.3	173	0.231	69.20	1,368	2.555	51.79
Mar-19	74	5.89	2.88	16	14.5	2.4	190	0.253	66.27	1,331	2.485	53.11
Mar-23	44	6.44	3.32	140	14.5	1.9	156	0.208	72.27	1,337	2.498	52.87
Mar-24	61	5.90	2.91	23	14.5	2.2	174	0.232	69.07	1,366	2.551	51.87
Mar-25	71	6.01	2.90	20	14.3	1.8	197	0.263	64.93	1,282	2.395	54.81
Mar-26	74	5.87	2.92	16	14.3	1.5	187	0.250	66.67	1,418	2.649	50.02
Apr-02	74	5.85	2.90	35	14.6	1.9	202	0.271	63.87	1,306	2.443	53.91
Apr-03	75	5.80	2.85	51	14.7	1.5	212	0.285	62.00	1,527	2.871	45.83
Apr-06	63	5.71	3.00	56	14.7	0.9	195	0.262	65.07	1,320	2.484	53.13
Apr-07	62	6.04	3.11	76	14.8	1.5	208	0.280	62.67	1,434	2.700	49.06
Apr-08	74	5.76	3.10	38	14.8	1.2	205	0.276	63.20	1,366	2.569	51.53
Apr-09	74	5.81	2.86	25	14.7	1.1	183	0.246	67.20	1,186	2.222	58.08
Apr-10	56	6.10	3.11	254	14.5	2.2	189	0.253	66.27	1,371	2.569	51.53
Apr-13	74	5.56	2.79	27	14.5	1.2	182	0.242	67.73	1,466	2.738	48.34
Apr-14	62	5.78	3.03	20	14.5	1.5	177	0.236	68.53	1,362	2.544	52.00
Apr-16	47	6.48	3.43	102	14.5	1.8	177	0.236	68.53	1,296	2.422	54.30
Apr-21	71	6.28	3.05	17	14.5	1.1	189	0.252	66.40	1,242	2.320	56.23
Apr-22	64	6.16	3.02	74	14.6	1.3	205	0.274	63.47	1,242	2.321	56.21
Apr-23	67	6.22	3.02	26	14.4	2.6	200	0.266	64.53	1,268	2.368	55.32

c: corrected to 3% O_2

TABLE 5-4. LONG TERM GR-SI TESTING AVERAGE DAILY EMISSIONS (Continued)

Date 1992	Avg. Load (MWe)	O_2 (%, Dry)	O_2 (%, Wet)	CO_c (ppm)	$CO_{2,c}$ (%)	HC_c (ppm)	$NO_{x,c}$ (ppm)	NO_x (lb/MBtu)	NO_x Red (%)	$SO_{2,c}$ (ppm)	SO_2 (lb/MBtu)	SO_2 Red Tot (%)
Jul-29	61	6.07	2.94	44	14.5	1.1	201	0.269	64.13	1,463	2.733	48.43
Jul-30	49	5.87	2.74	83	14.4	1.6	183	0.244	67.47	1,354	2.531	52.25
Jul-31	45	6.07	2.99	197	14.7	4.6	172	0.230	69.33	1,391	2.599	50.96
Aug-03	46	6.10	3.06	142	14.7	1.3	167	0.223	70.27	1,461	2.731	48.47
Aug-05	64	5.71	2.94	18	14.9	1.1	198	0.264	64.80	1,485	2.775	47.64
Aug-11	75	5.30	2.37	14	14.7	1.9	188	0.252	66.40	1,465	2.737	48.36
Aug-12	75	5.78	2.74	16	14.8	1.5	198	0.265	64.67	1,460	2.728	48.53
Aug-13	74	6.10	3.21	15	14.9	1.3	233	0.312	58.40	1,487	2.779	47.57
Aug-14	75	5.77	2.61	17	14.7	1.3	196	0.262	65.07	1,629	3.042	42.60
Aug-17	73	5.72	2.83	24	14.5	2.3	204	0.272	63.73	1,317	2.459	53.60
Aug-18	58	5.29	2.72	37	14.5	15.2	141	0.189	74.80	1,292	2.414	54.45
Aug-19	62	5.89	3.09	18	14.5	0.8	161	0.215	71.33	1,448	2.706	48.94
Aug-20	51	6.14	3.10	28	14.6	3.5	143	0.190	74.67	1,199	2.239	57.75
Aug-21	56	5.99	3.02	26	14.6	1.0	140	0.187	75.07	1,272	2.376	55.17
Aug-24	54	5.90	3.05	23	14.5	1.1	142	0.189	74.80	1,427	2.666	49.70
Aug-25	54	5.83	3.06	25	14.5	1.0	140	0.187	75.07	1,337	2.499	52.85
Aug-26	47	6.52	3.26	35	14.5	1.0	156	0.209	72.13	1,224	2.287	56.85
Aug-27	62	5.96	3.13	27	14.4	0.9	173	0.231	69.20	1,078	2.014	62.00
Aug-28	63	5.75	2.76	13	14.4	0.1	134	0.179	76.13	1,546	2.888	45.51
Sep-02	73	5.65	2.59	15	14.1	0.5	181	0.241	67.87	1,183	2.210	58.30
Sep-09	74	5.55	2.85	17	14.5	1.0	185	0.247	67.07	1,329	2.483	53.15
Sep-10	75	5.67	2.71	15	14.5	1.0	188	0.251	66.53	1,313	2.452	53.74
Sep-11	74	5.60	2.86	19	14.5	0.5	169	0.226	69.87	1,395	2.606	50.83
Sep-16	72	6.14	3.06	16	14.4	0.7	218	0.291	61.20	1,175	2.194	58.60
Sep-21	72	5.61	2.51	15	14.5	0.4	183	0.245	67.33	1,253	2.340	55.85
Sep-22	50	6.33	3.25	101	14.5	0.6	180	0.241	67.87	1,140	2.129	59.83
Sep-23	50	6.34	3.29	86	14.7	0.5	179	0.239	68.13	1,162	2.171	59.04
Sep-24	51	6.43	3.35	89	14.2	18.2	185	0.246	67.20	1,194	2.232	57.89
Sep-30	58	6.07	3.17	59	14.2	0.4	181	0.242	67.73	1,162	2.171	59.04
Oct-12	57	6.05	3.01	67	14.4	2.0	171	0.228	69.60	1,351	2.525	52.36
Oct-19	72	5.87	2.74	18	14.2	0.6	188	0.252	66.40	1,341	2.506	52.72
Average	62	6.00	3.02	57	14.5	1.9	184	0.246	67.26	1,343	2.510	52.65
Maximum	75	6.78	3.74	254	14.9	18.2	233	0.312	76.13	1,629	3.042	62.00
Minimum	44	5.29	2.37	13	14.0	0.1	134	0.179	58.40	1,078	2.014	42.60
St. Dev.	10	0.32	0.27	53	0.2	2.6	20	0.027	3.65	108	0.203	3.83

c: corrected to 3% O2

TABLE 5-5. LONG TERM GR-SI TESTING OPERATING CONDITION SUMMARY

Date 1992	Test Dur. (Hr:Min)	Steam (lb/hr)	Coal Flow (lb/min)	Reb. Gas (scfm)	Gas Heat (%)	OFA, Tot (scfm)	OFA Fraction	FGR (scfm)	Burner Tilt (deg)	SR1	SR2	SR3
Jan-10	3:04	389,154	726	1,550	15.7	19,385	0.179	3,121	23.0	1.086	0.982	1.196
Jan-13	6:17	420,600	745	1,863	17.7	21,278	0.186	3,052	26.9	1.112	0.978	1.198
Jan-21	6:10	380,779	684	1,729	18.0	23,923	0.218	2,933	23.1	1.110	0.982	1.251
Jan-22	5:51	328,711	599	1,520	19.5	22,123	0.228	2,825	23.7	1.127	0.980	1.258
Jan-23	5:05	379,217	681	1,743	19.7	22,712	0.211	2,944	13.4	1.131	0.924	1.226
Jan-27	3:13	342,771	615	1,547	19.3	21,439	0.215	2,760	22.9	1.153	0.946	1.263
Jan-28	5:05	382,532	692	1,735	19.4	23,099	0.211	2,824	20.2	1.140	0.935	1.235
Jan-29	2:57	459,722	802	2,034	19.5	26,129	0.213	2,725	13.2	1.105	0.904	1.191
Jan-30	5:00	379,464	680	1,623	18.5	21,327	0.203	2,794	23.8	1.118	0.926	1.213
Feb-06	3:03	540,712	950	2,296	18.8	35,672	0.248	2,650	8.1	1.056	0.870	1.189
Feb-19	7:25	473,020	844	2,027	18.6	26,723	0.205	2,634	18.6	1.129	0.927	1.214
Feb-20	4:54	337,425	608	1,421	18.2	21,285	0.224	2,671	21.5	1.093	0.902	1.231
Feb-21	3:04	432,847	779	1,847	18.5	27,103	0.223	2,635	19.4	1.112	0.916	1.230
Feb-24	5:00	341,717	610	1,446	18.7	21,033	0.219	2,716	22.2	1.117	0.915	1.241
Feb-25	4:00	353,644	648	1,492	18.1	21,426	0.210	2,741	21.4	1.133	0.938	1.248
Feb-26	7:55	516,901	920	2,197	18.6	30,158	0.218	2,742	19.2	1.086	0.897	1.182
Feb-28	8:55	450,355	806	1,895	18.3	27,883	0.223	2,627	17.3	1.107	0.918	1.221
Mar-02	6:28	544,550	966	2,302	18.5	31,478	0.215	2,499	22.1	1.106	0.914	1.193
Mar-03	5:28	351,176	623	1,458	18.3	21,614	0.216	2,763	26.9	1.148	0.953	1.270
Mar-04	6:50	420,472	761	1,794	18.4	24,164	0.206	2,679	25.5	1.119	0.927	1.212
Mar-10	4:15	468,164	828	2,010	18.8	26,935	0.213	2,683	23.6	1.104	0.910	1.195
Mar-11	5:06	549,075	960	2,330	18.7	31,247	0.217	2,719	23.0	1.090	0.898	1.176
Mar-12	3:28	435,651	784	1,858	18.5	25,605	0.213	2,815	26.6	1.113	0.922	1.210
Mar-13	4:37	506,094	893	2,151	18.6	30,263	0.220	2,685	23.4	1.114	0.918	1.210
Mar-16	6:41	481,220	857	2,053	18.6	30,052	0.228	2,912	24.6	1.098	0.907	1.209
Mar-17	6:14	553,848	976	2,359	18.8	35,403	0.239	2,482	6.1	1.072	0.883	1.189
Mar-19	2:14	557,174	976	2,383	18.9	36,805	0.247	2,468	15.6	1.070	0.880	1.196
Mar-23	5:25	325,431	582	1,387	18.5	20,548	0.226	2,546	21.4	1.097	0.909	1.231
Mar-24	8:49	460,407	811	1,970	18.8	27,155	0.219	2,453	19.9	1.102	0.908	1.199
Mar-25	8:49	538,187	940	2,286	18.9	34,940	0.243	2,545	20.4	1.075	0.885	1.198
Mar-26	4:34	553,423	974	2,352	18.8	36,599	0.246	2,525	20.3	1.073	0.885	1.200
Apr-02	7:28	551,590	981	2,266	18.1	35,608	0.239	2,607	16.6	1.074	0.892	1.199
Apr-03	3:45	577,896	1084	1,655	12.8	30,306	0.197	3,273	21.4	1.066	0.940	1.195
Apr-06	6:45	468,314	895	1,340	12.6	24,788	0.193	4,272	26.5	1.071	0.948	1.206
Apr-07	3:55	468,630	890	1,284	12.1	23,700	0.186	4,063	26.9	1.085	0.964	1.214
Apr-08	8:54	553,470	1049	1,576	12.5	29,369	0.194	4,274	21.6	1.085	0.960	1.213
Apr-09	8:48	554,190	1012	1,970	15.7	33,536	0.225	3,983	17.2	1.067	0.911	1.195
Apr-10	1:15	424,248	777	1,514	15.7	23,694	0.204	3,904	29.1	1.101	0.942	1.214
Apr-13	8:00	552,063	971	2,382	19.0	36,734	0.249	2,520	22.1	1.068	0.878	1.190
Apr-14	7:27	461,155	823	1,986	18.7	31,220	0.247	2,623	20.1	1.076	0.888	1.207
Apr-16	6:02	347,162	629	1,474	18.3	24,102	0.244	2,529	20.9	1.088	0.904	1.239
Apr-21	6:21	531,414	935	2,255	18.7	34,960	0.243	2,579	-0.5	1.089	0.898	1.209
Apr-22	6:18	482,486	851	2,056	18.7	31,200	0.238	2,826	24.7	1.088	0.898	1.207
Apr-23	3:45	502,086	883	2,145	18.9	33,248	0.244	2,618	22.0	1.084	0.894	1.208

TABLE 5-5. LONG TERM GR-SI TESTING OPERATING CONDITION SUMMARY (Continued)

Date 1992	Test Dur. (Hr:Min)	Steam (lb/hr)	Coal Flow (lb/min)	Reb. Gas (scfm)	Gas Heat (%)	OFA, Tot (scfm)	OFA Fraction	FGR (scfm)	Burner Tilt (deg)	SR1	SR2	SR3
Jul-29	2:45	452,259	810	1,931	18.5	28,849	0.233	3,963	23.1	1.087	0.900	1.202
Jul-30	5:45	358,398	652	1,520	18.2	22,636	0.231	2,750	26.9	1.062	0.884	1.189
Jul-31	4:45	329,116	595	1,407	18.4	20,523	0.225	2,759	26.9	1.082	0.899	1.205
Aug-03	5:35	339,622	617	1,440	18.2	21,901	0.232	2,717	26.9	1.076	0.895	1.210
Aug-05	5:10	472,090	844	1,994	18.4	28,128	0.219	2,617	22.8	1.107	0.917	1.201
Aug-11	2:40	576,925	999	2,433	18.8	36,131	0.245	2,519	-4.0	1.045	0.860	1.158
Aug-12	4:15	566,551	993	2,383	18.7	36,224	0.242	2,557	14.7	1.069	0.883	1.186
Aug-13	3:45	553,956	976	2,338	18.6	35,919	0.237	2,562	23.1	1.108	0.915	1.221
Aug-14	:24	573,120	998	2,423	18.8	36,053	0.240	2,511	17.2	1.067	0.879	1.179
Aug-17	7:00	546,828	958	2,339	18.9	36,598	0.251	2,673	26.8	1.066	0.878	1.192
Aug-18	5:50	437,303	766	1,843	18.7	28,363	0.246	2,743	26.9	1.052	0.870	1.184
Aug-19	5:00	462,437	820	1,955	18.5	30,265	0.240	2,709	26.9	1.097	0.908	1.211
Aug-20	6:55	389,120	679	1,651	18.9	25,518	0.243	2,892	26.9	1.079	0.891	1.214
Aug-21	6:45	419,876	746	1,780	18.5	27,525	0.240	2,830	26.9	1.078	0.892	1.207
Aug-24	3:25	410,617	717	1,745	18.9	26,760	0.242	2,632	26.9	1.089	0.898	1.210
Aug-25	6:50	406,722	715	1,707	18.6	26,355	0.240	2,766	26.9	1.080	0.894	1.210
Aug-26	9:50	358,649	626	1,508	18.7	23,259	0.238	2,866	26.9	1.090	0.902	1.226
Aug-27	7:35	471,330	828	1,985	18.6	30,901	0.241	2,823	26.9	1.090	0.901	1.215
Aug-28	:20	465,328	828	1,979	18.5	30,284	0.242	2,862	9.1	1.063	0.878	1.186
Sep-02	6:20	548,204	964	2,323	18.7	35,672	0.247	2,642	9.2	1.054	0.870	1.176
Sep-09	5:45	556,195	977	2,355	18.6	35,983	0.242	2,569	11.1	1.077	0.889	1.193
Sep-10	8:00	568,195	994	2,404	18.7	36,844	0.246	2,669	17.5	1.064	0.877	1.183
Sep-11	4:25	554,705	977	2,342	18.6	32,058	0.216	2,740	16.7	1.113	0.919	1.194
Sep-16	5:57	542,597	951	2,318	18.8	36,226	0.247	2,598	21.2	1.089	0.896	1.209
Sep-21	7:31	545,511	953	2,324	18.9	33,691	0.237	2,601	7.6	1.065	0.877	1.168
Sep-22	15:08	370,859	666	1,585	18.5	24,238	0.234	2,903	26.7	1.099	0.911	1.225
Sep-23	16:49	367,463	668	1,584	18.5	24,487	0.235	2,972	25.2	1.101	0.913	1.229
Sep-24	24:01	380,486	682	1,626	18.5	25,172	0.235	2,858	25.4	1.107	0.918	1.233
Sep-30	54:52	429,634	772	1,847	18.6	28,775	0.241	2,684	22.7	1.096	0.906	1.218
Oct-12	28:01	422,285	755	1,732	18.0	27,642	0.240	2,407	24.8	1.076	0.895	1.207
Oct-19	32:07	547,716	965	2,248	18.2	35,133	0.242	2,215	24.0	1.068	0.886	1.187
Average		460,710	821	1,915	18.2	28,614	0.228	2,811	20.9	1.091	0.909	1.208
Maximum		577,896	1084	2,433	19.7	36,844	0.251	4,274	29.1	1.153	0.982	1.270
Minimum		325,431	582	1,284	12.1	19,385	0.179	2,215	-4.0	1.045	0.860	1.158
St. Dev.		79,748	138	341	1.5	5,375	0.017	413	6.6	0.023	0.028	0.021

TABLE 5-6. SUMMARY OF BASELINE LONG-TERM THERMAL PERFORMANCE

Average Load	45 MWe	61 MWe	72 MWe	Predicted*
Process Variables				
Exit Plant O_2 (%)	3.57	3.23	2.90	2.80
Steam Side Temperatures (°F)				
Exit Secondary Superheater	941	991	993	1,005
Exit Primary Superheater	779	837	841	854
Exit High Temp Reheater	897	982	992	1,005
SH Steam Attemperation (lb/hr)	4,215	7,004	6,678	14,500
Heat Transfer (MBtu/hr)				
Furnace Waterwalls	241	292	351	356
Secondary Superheater	39	53	60	64
Reheater	43	61	70	76
Primary Superheater	63	100	121	130
Economizer	15	19	21	27
Sootblowers On (%)	7	14	7	N.D.
Burner Tilt (degrees)	25	15	8	N.D.
Econ. Inlet Gas Temp (°F)	630	654	672	N.D.
Air Heater Gas Out Temp (°F)	314	326	317	N.D.
ASME Heat Loss Calculation (%)				
Dry Gas	5.39	5.69	5.29	5.04
Moisture from Fuel	1.73	1.75	1.74	1.45
Moisture from Combustion	3.88	3.90	3.89	4.02
Combustible in Refuse	0.48	0.45	0.50	0.30
Radiation	0.48	0.37	0.33	0.33
Unmeasured	1.50	1.50	1.50	1.50
Total Losses	13.46	13.66	13.25	12.64
Thermal Efficiency (%)	86.54	86.34	86.75	87.36
Net Heat Rate (Btu/kWh)	10,464	10,437	10,340	N.D.

*:Heat Transfer Modeling @ 100% Load
N.D.: Not Determined

TABLE 5-7. SUMMARY OF GR LONG-TERM THERMAL PERFORMANCE

Average Load	44 MWe	60 MWe	72 MWe	Predicted*
Process Variables				
Percent Gas Heat Input	18.50	17.68	17.80	18.00
Ca/S Molar Ratio	0.00	0.00	0.00	0.00
Exit Plant O_2 (%)	3.66	3.07	2.96	2.80
Steam Side Temperatures (°F)				
Exit Secondary Superheater	974	988	994	1,005
Exit Primary Superheater	802	827	845	883
Exit High Temp Reheater	937	978	999	1,005
SH Steam Attemperation (lb/hr)	4,273	5,237	7,881	22,500
Heat Transfer (MBtu/hr)				
Furnace Waterwalls	216	296	347	345
Secondary Superheater	41	52	61	62
Reheater	44	60	72	76
Primary Superheater	67	96	122	136
Economizer	15	19	22	29
Sootblowers On (%)	7	6	16	N.D.
Burner Tilt (degrees)	25.16	15.94	3.48	N.D.
Econ. Inlet Gas Temp (°F)	636	653	668	N.D.
Air Heater Gas Out Temp (°F)	318	321	321	N.D.
ASME Heat Loss Calculation (%)				
Dry Gas	5.85	5.26	5.27	5.10
Moisture from Fuel	1.45	1.47	1.45	1.20
Moisture from Combustion	5.03	4.98	5.05	5.34
Combustible in Refuse	0.33	0.40	0.39	0.49
Radiation	0.40	0.39	0.33	0.33
Unmeasured	1.50	1.50	1.50	1.50
Total Losses	14.56	14.00	13.99	13.96
Thermal Efficiency (%)	85.44	86.00	86.01	86.04
Net Heat Rate (Btu/kWh)	10,743	10,534	10,428	N.D.

*:Heat Transfer Modeling @ 100% Load
N.D.: Not Determined

TABLE 5-8. SUMMARY OF SI LONG-TERM THERMAL PERFORMANC]

Average Load	43 MWe
Process Variables	
Percent Gas Heat Input	0.00
Ca/S Molar Ratio	1.95
Exit Plant O_2 (%)	3.43
Steam Side Temperatures (°F)	
Exit Secondary Superheater	950
Exit Primary Superheater	803
Exit High Temp Reheater	895
SH Steam Attemperation (lb/hr)	2,673
Heat Transfer (MBtu/hr)	
Furnace Waterwalls	232
Secondary Superheater	33
Reheater	41
Primary Superheater	67
Economizer	15
Sootblowers On (%)	11
Burner Tilt (degrees)	23.88
Econ. Inlet Gas Temp (°F)	665
Air Heater Gas Out Temp (°F)	357
ASME Heat Loss Calculation (%)	
Dry Gas	7.33
Moisture from Fuel	1.75
Moisture from Combustion	4.01
Combustible in Refuse	0.50
Radiation	0.51
Unmeasured	1.50
Total Losses	15.60
Thermal Efficiency (%)	84.40
Net Heat Rate (Btu/kWh)	10,677

TABLE 5-9. SUMMARY OF GR-SI LONG-TERM THERMAL PERFORMANCE

Average Load	45 MWe	59 MWe	72 MWe	Predicted*
Process Variables				
Percent Gas Heat Input	18.53	17.80	17.67	18.00
Ca/S Molar Ratio	1.74	1.73	1.78	2.00
Exit Plant O_2 (%)	3.33	3.00	2.81	2.80
Steam Side Temperatures (°F)				
Exit Secondary Superheater	978	986	995	1,005
Exit Primary Superheater	825	853	882	883
Exit High Temp Reheater	925	958	989	1,005
SH Steam Attemperation (lb/hr)	4,209	7,300	12,176	16,500
Heat Transfer (MBtu/hr)				
Furnace Waterwalls	229	298	352	349
Secondary Superheater	37	45	55	61
Reheater	43	56	68	74
Primary Superheater	73	102	133	133
Economizer	16	20	24	29
Sootblowers On (%)	21	26	36	N.D.
Burner Tilt (degrees)	24.39	23.17	19.16	N.D.
Econ. Inlet Gas Temp (°F)	668	690	714	N.D.
Air Heater Gas Out Temp (°F)	344	348	350	N.D.
ASME Heat Loss Calculation (%)				
Dry Gas	5.96	5.89	5.78	5.26
Moisture from Fuel	1.44	1.45	1.45	1.20
Moisture from Combustion	5.19	5.15	5.15	5.35
Combustible in Refuse	0.37	0.42	0.41	0.54
Radiation	0.45	0.39	0.33	0.33
Unmeasured	1.50	1.50	1.50	1.50
Total Losses	14.91	14.80	14.62	14.18
Thermal Efficiency (%)	85.09	85.20	85.38	85.82
Net Heat Rate (Btu/kWh)	10,724	10,581	10,509	N.D.

*:Heat Transfer Modeling @ 100% Load
N.D.: Not Determined

reheat steam temperatures, superheat attemperation spray, heat absorption profile, flue gas temperature, thermal efficiency, and net heat rate. Hennepin Unit 1 produces both superheat (main) and reheat steam with a design point temperature of 1,005°F (541°C). The operators typically consider this design point to be a maximum and operate conservatively with steam temperatures in the range of 980 to 995°F (527 to 535°C), regardless of whether GR or SI is in service. Three systems are used to control these temperatures as load, excess air, boiler fouling, and other parameters vary.

- Burner Tilt Burner tilt adjusts the position of flames in the furnace. When the burners are tilted up, furnace waterwall heat absorption is reduced shifting heat to the superheater and reheater sections and increasing the main and reheat steam temperatures. Under normal operation, the burner tilt is controlled automatically to achieve the reheat temperature set point.

- Reheat Attemperation Feedwater is sprayed into the reheat steam for further reheat temperature control. Since the attemperation water bypasses the high pressure turbine stages, it increases heat rate (reduces thermal efficiency). Accordingly, the reheat attemperation is normally used as a backup system. Throughout this program, the operators maintained reheat attemperation flow at a very low level.

- Main Steam Attemperation Feedwater is also sprayed into the superheat steam to control its temperature. This provides a means to adjust superheat steam temperature independent of reheat steam temperature, which is controlled primarily by burner tilt.

Figure 5-18 shows the reheat temperature as a function of load for both baseline and GR-SI operation. While there is some data scatter, for most baseline conditions the

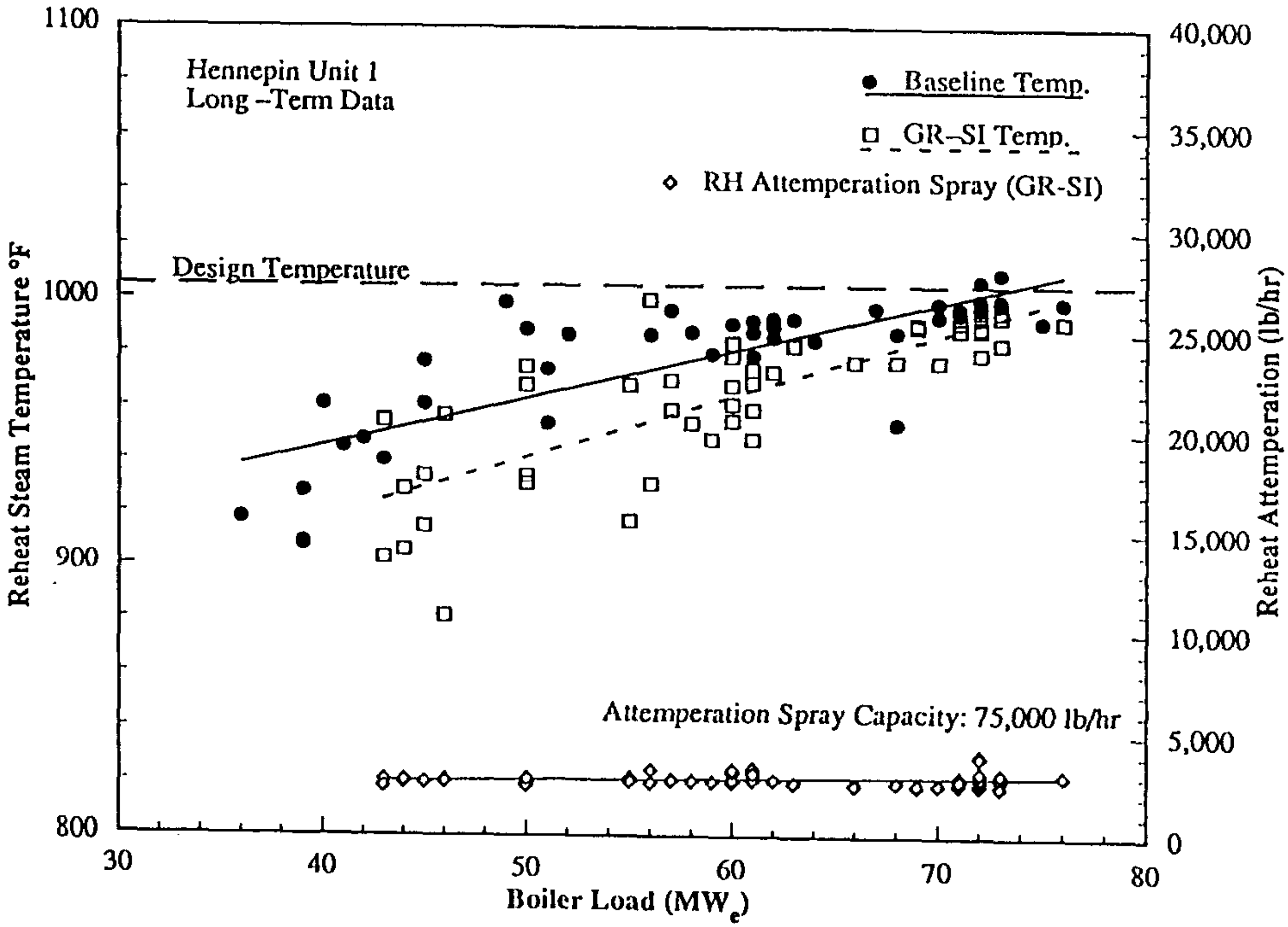


Figure 5-18. Impact of GR-SI on reheat steam temperature

adjustment of burner tilt maintains the reheat temperature at the set point from full load down to about 50 MW_e. Below 50 MW_e the burner tilts are at the full up position and further load reduction causes reheat temperature to sag. The reheat attemperation is maintained constant at about 4% of capacity (essentially leakage flow).

Fouling of the reheater, caused by GR-SI operation, requires higher burner tilts to maintain reheat temperature. This is illustrated in Figure 5-19 which shows the reheat steam temperature and burner tilts as functions of the time after initiation of SI. Over the first hour of SI, the burner tilts increased monotonically as deposits built on the reheater; reheat temperature was maintained at the set point. Operation of the sootblowers at the end of the first hour removed the deposits, restoring the reheater heat absorption. This caused a momentary overshoot in reheat temperature until the burner tilts moved downward restoring the set point. A second sootblowing cycle is also shown.

As a result of reheater fouling, the GR-SI data in Figure 5-18 show a slightly reduced reheat temperature compared to baseline operation. Since the duration of the SI and scheduling of sootblowing cycles affect reheat temperature, there is substantial data scatter.

Figures 5-20, 5-21, and 5-22 show the superheat steam effects of GR-SI with baseline conditions for comparison. Under both GR-SI and baseline conditions, superheat steam temperature was maintained at close to the set point over the full load range as the burner tilts adjusted automatically to maintain reheat steam temperature as discussed above. Figure 5-22 shows that the superheat steam attemperation under GR-SI operation is greater than for baseline operation at full load. This is a consequence of the upward burner tilt required to maintain reheat temperature which also increases superheat temperature. The superheat attemperation was increased to compensate. It should be noted that while the superheat attemperation increased with

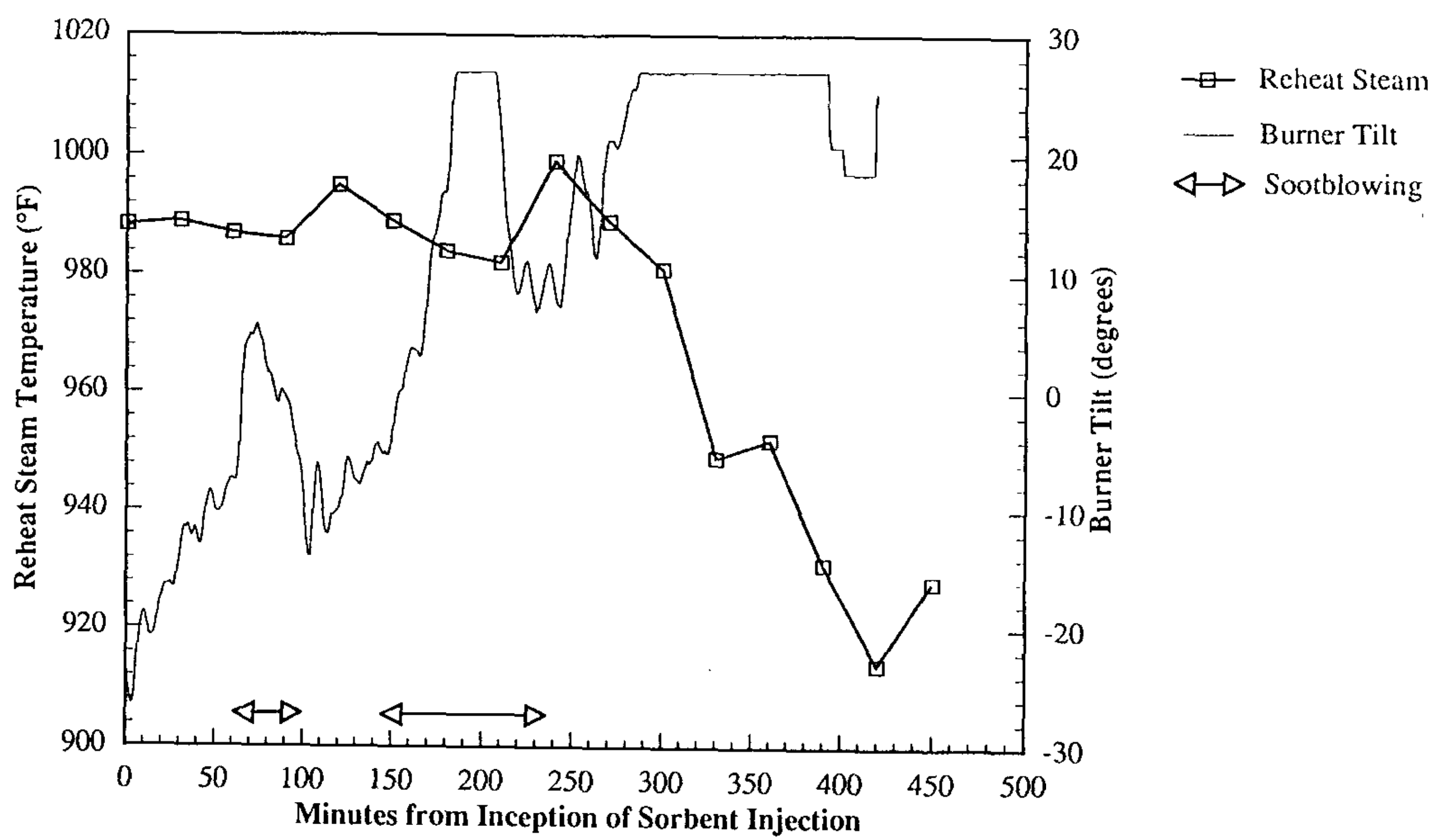


Figure 5-19. Typical effect of burner tilt on reheat steam temperature.

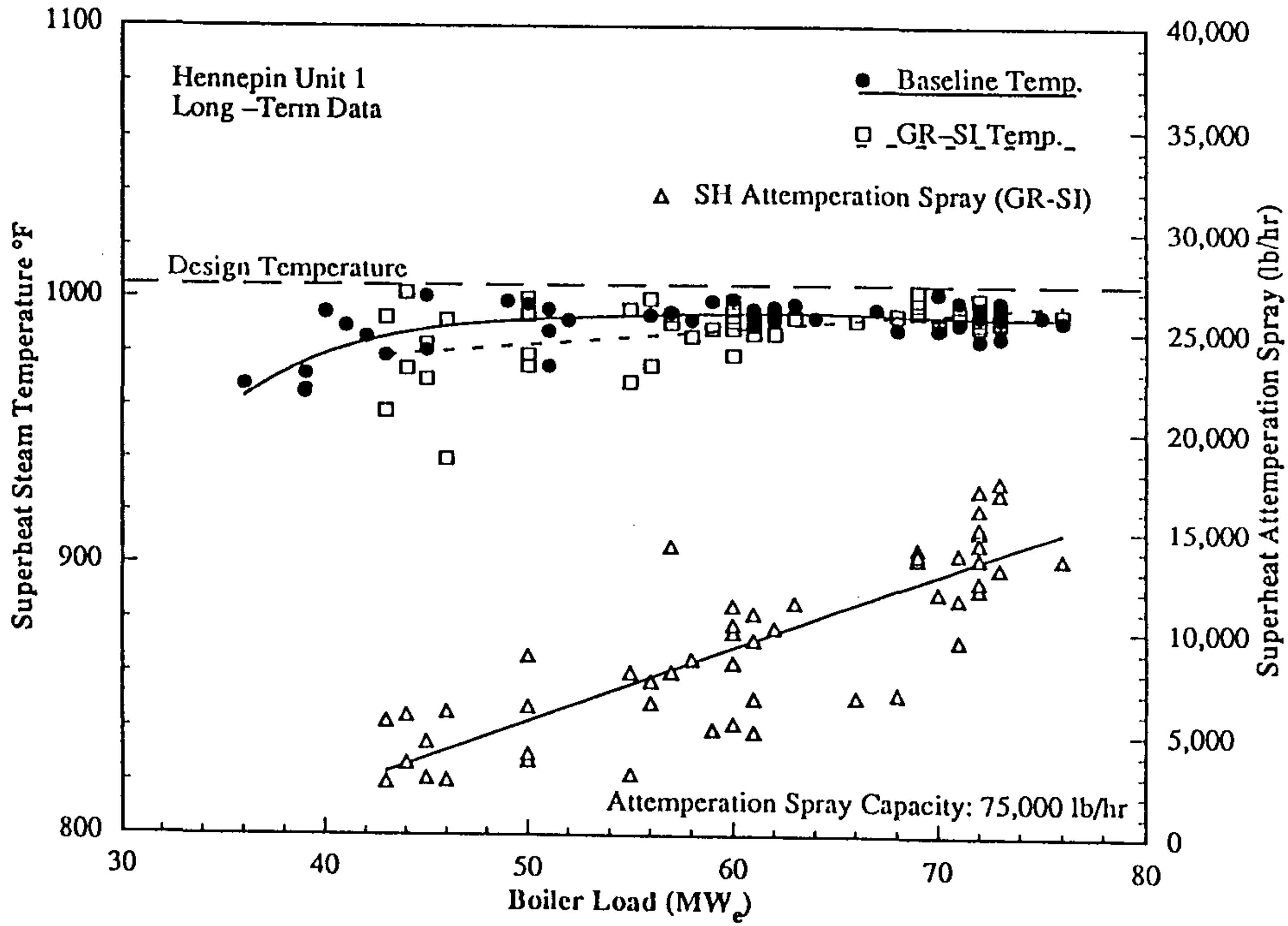


Figure 5-20. Impact of GR–SI on superheat steam temperature (attemperation spray indicated)

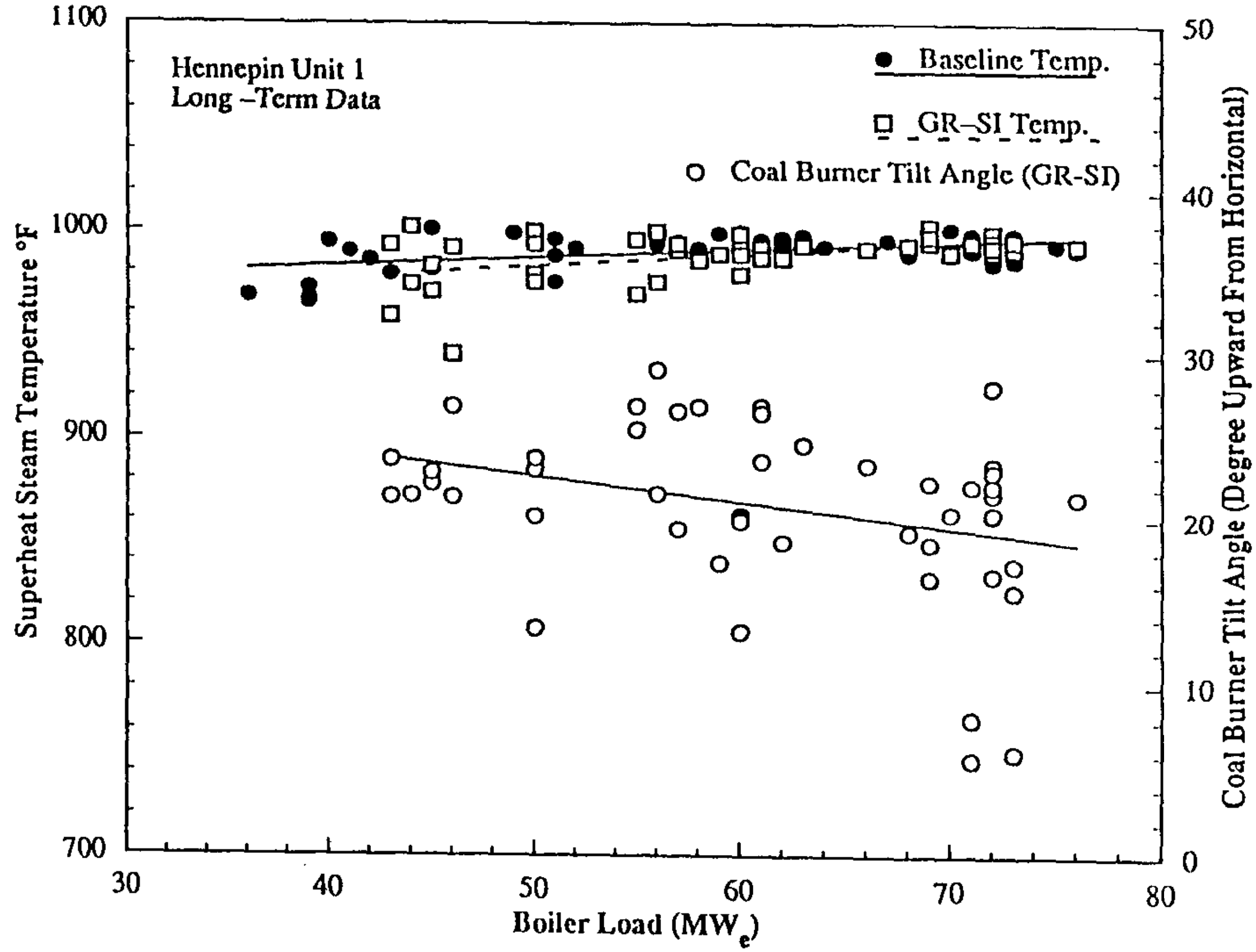


Figure 5-21. Impact of GR–SI on superheat steam temperature (burner tilt angle indicated)

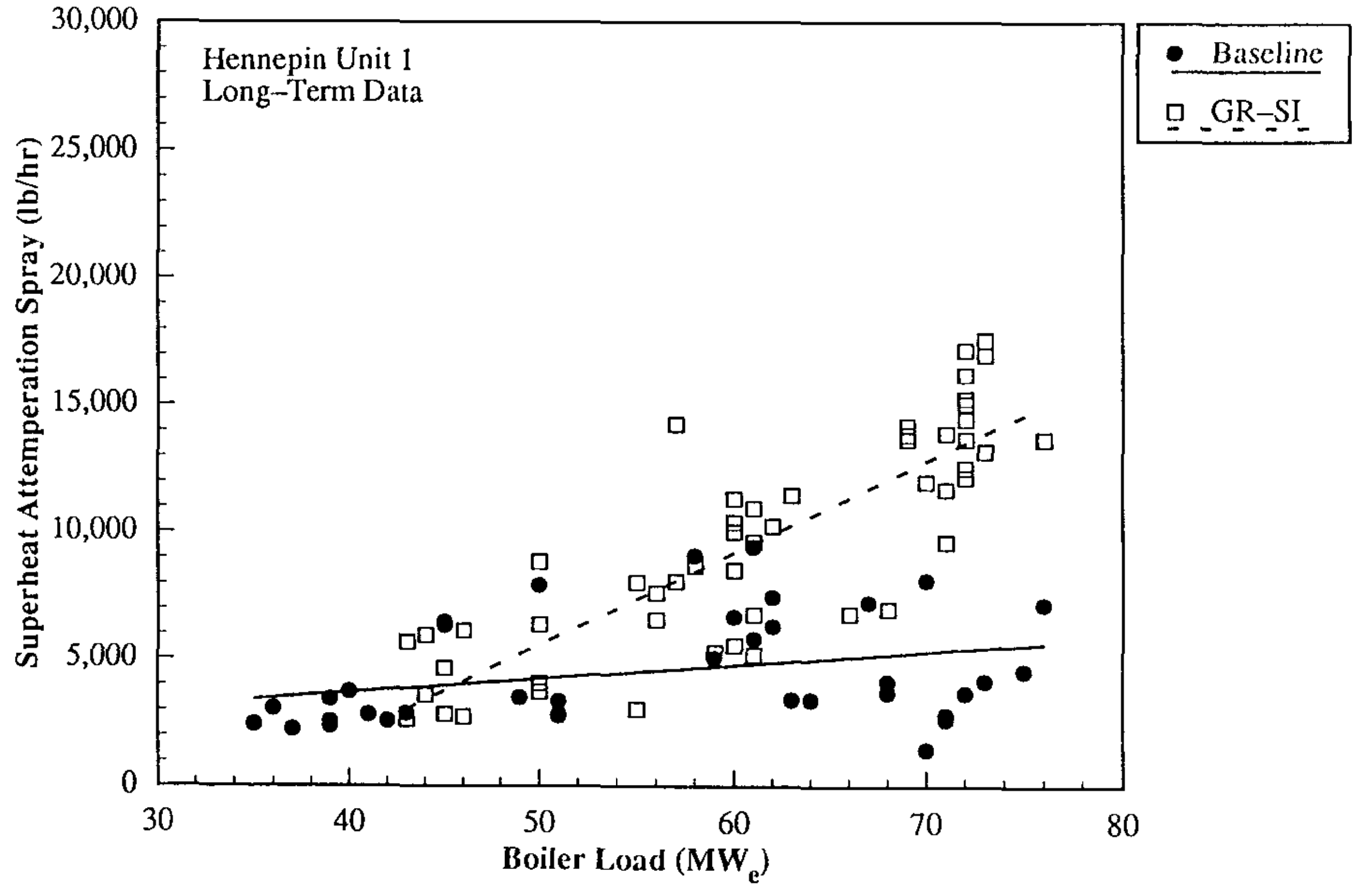


Figure 5-22. Impact of GR–SI on superheat steam attemperation.

GR-SI, the maximum flow rate (nominally 16,000 lb/hr [2.0 kg/s]) was only about 21% of capacity and did not limit boiler performance.

Heat absorption profiles were studied for Hennepin Unit 1 to determine the effect of GR, SI, and GR–SI on the heat absorption by each heat exchanger. Heat absorptions were calculated by analyzing the temperatures and flow rates on both sides (steam and combustion products). Five heat exchangers were evaluated including the furnace water wall, reheater, primary superheater, secondary superheater and the economizer. The air heater heat absorption, which is accounted for in the thermal efficiency of the unit, was not included in this thermal performance evaluation because of significant air leakage. In Figures 5–23 through 5–25 the heat absorption profiles are shown at 72 MW_e, 60 MW_e, and 45 MW_e, respectively.

GR operation can affect the thermal performance of the unit in two ways. First, GR affects the furnace heat release profile and second, GR operation changes local stoichiometric ratios and particulate loading resulting in minor changes in lower and upper furnace deposition patterns. During the long–term demonstration, GR operational data showed little impact on the heat absorption profile. As a result, steam temperatures also showed very little variation due to GR operation. At full load a small decrease in furnace water wall heat absorption and small increases in heat absorption in the convective heat exchangers were calculated. The same pattern was evident in low load (45 MW_e) data but at the intermediate load (60 MW_e) the average data showed an increase in furnace heat absorption and small reductions by convective heat absorption. The overall impact of GR operation on the heat absorption profile was very minor. The boiler heat absorption was enhanced by the relatively clean furnace maintained day to day while the boiler cycled out of service during most evenings.

In addition to the impacts caused by GR, the GR-SI thermal performance was affected by the increase in particulate loading through the upper furnace and convective pass.

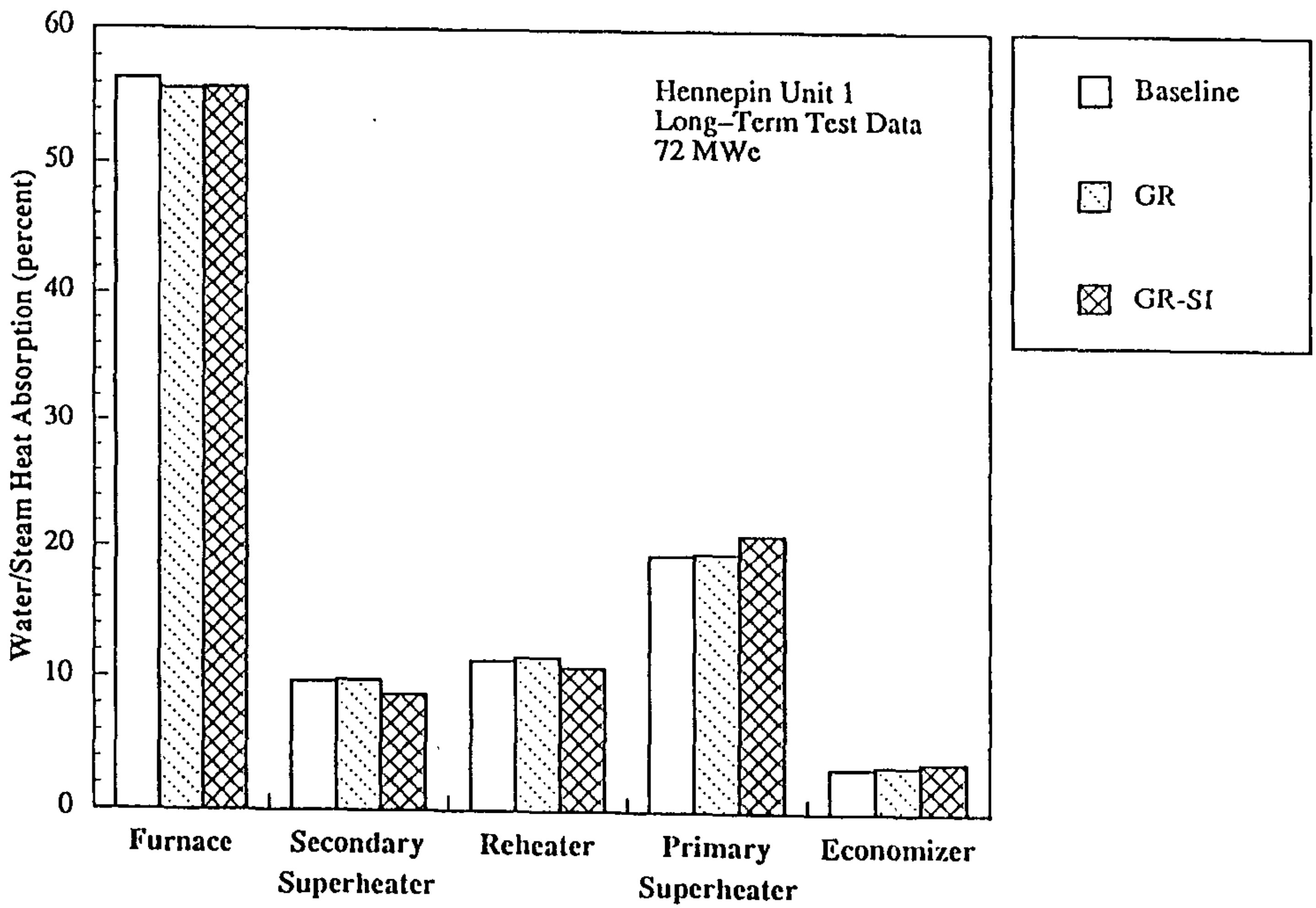


Figure 5-23. Heat absorption distribution at 72 MWe

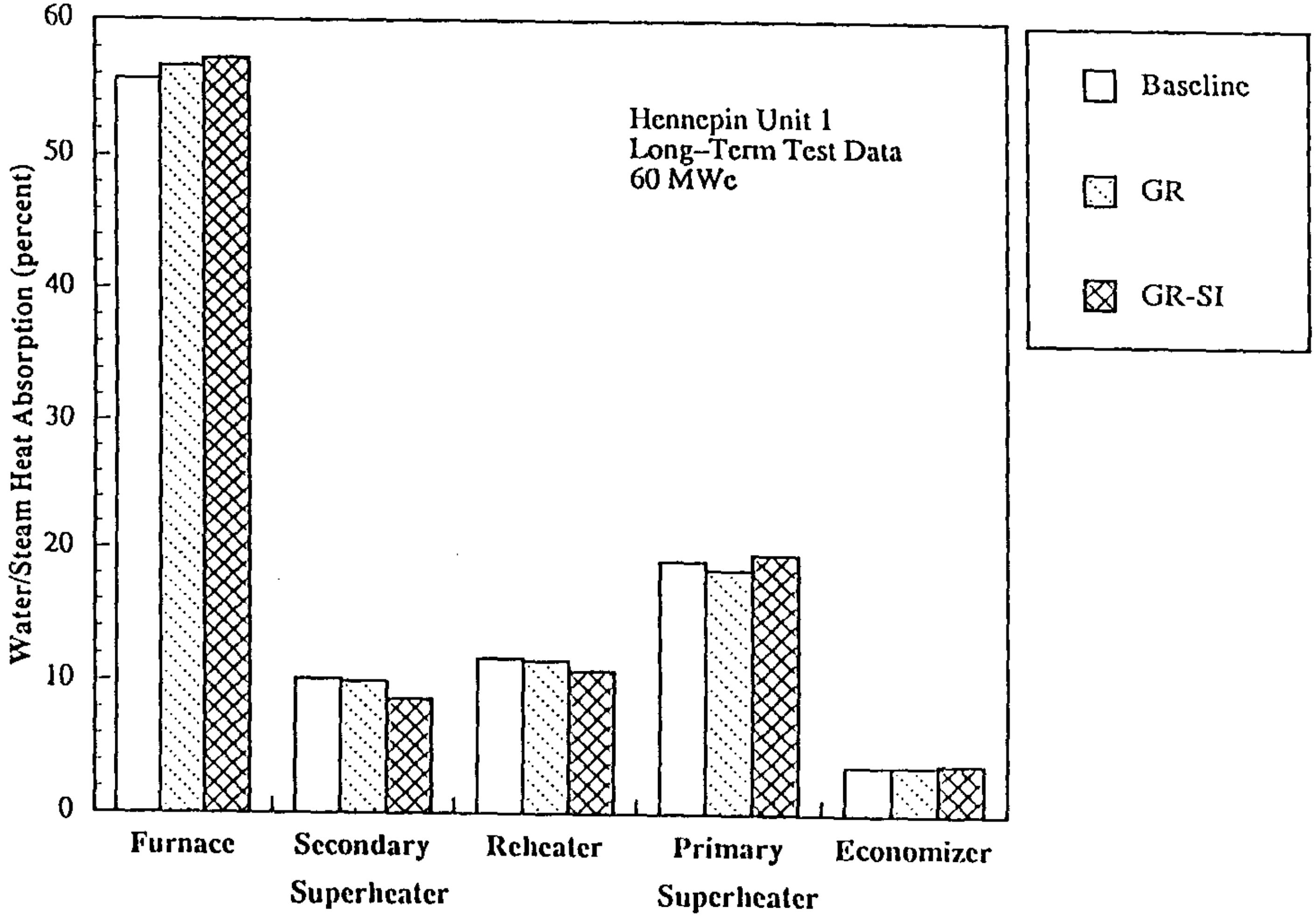


Figure 5-24. Heat absorption distribution at 60 MWe

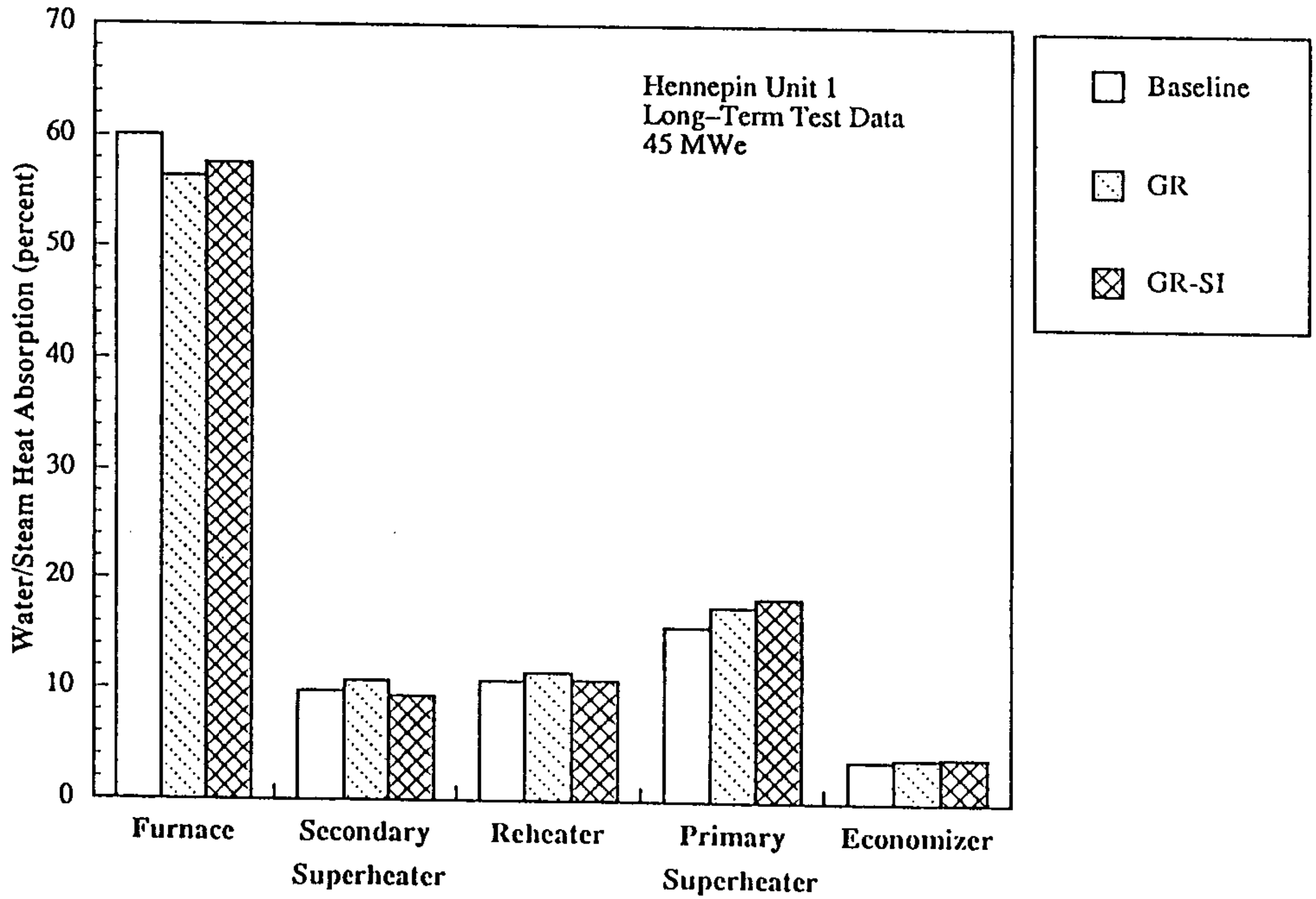


Figure 5–25. Heat absorption distribution at 45 MWe.

The increased particulate loading caused a familiar pattern over all loads. GR-SI had a relatively minor impact on furnace heat absorption, but more significant effect on the heat absorption by the secondary superheater, reheater, and primary superheater. The changes in heat absorption during GR-SI operation relative to the baseline case at full load were:

- Furnace 0.64% decrease
- Secondary Superheater 0.93% decrease
- Reheater 0.48% decrease
- Primary Superheater 1.62% increase
- Economizer 0.43% increase

The reduction in secondary superheat and reheat heat absorptions and increase in primary superheat absorption was consistent through the load range and was a direct impact of sorbent fouling. In order to decrease the impact of sorbent deposition, sootblowing optimization tests were conducted.

Because of the shift in heat absorption from the furnace and the upper convective pass to the convective backpass, the flue gas temperatures measured at the economizer inlet increased with GR-SI relative to baseline operation, as shown in Figure 5-26a. This increase in flue gas temperature had the following impacts:

- Reduction in thermal efficiency (increase in dry gas heat loss)

- Increase in temperature and velocity of the flue gas at the inlet of the humidification duct, requiring higher levels of humidification, possibly resulting in an increase in moisture entering the ESP

- Higher fly ash resistivity, which has been found to vary strongly with temperature, thus potentially reducing the collection efficiency of the

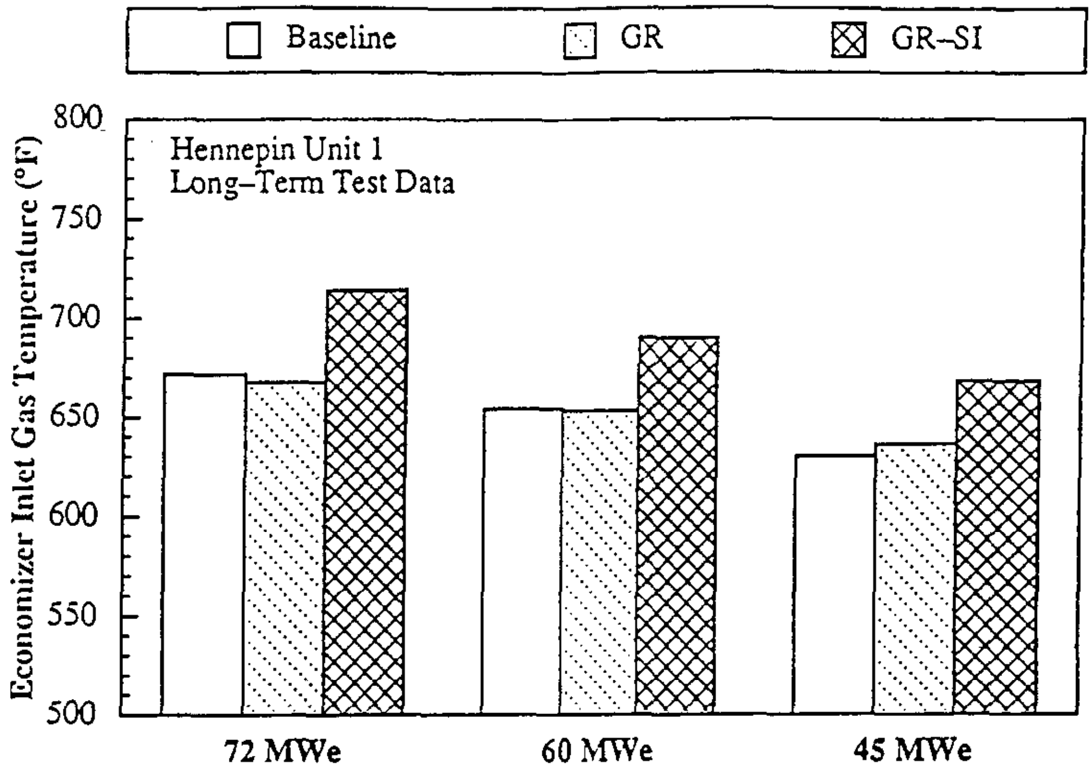


Figure 5–26a Impact of Long-Term testing on economizer inlet gas temperature

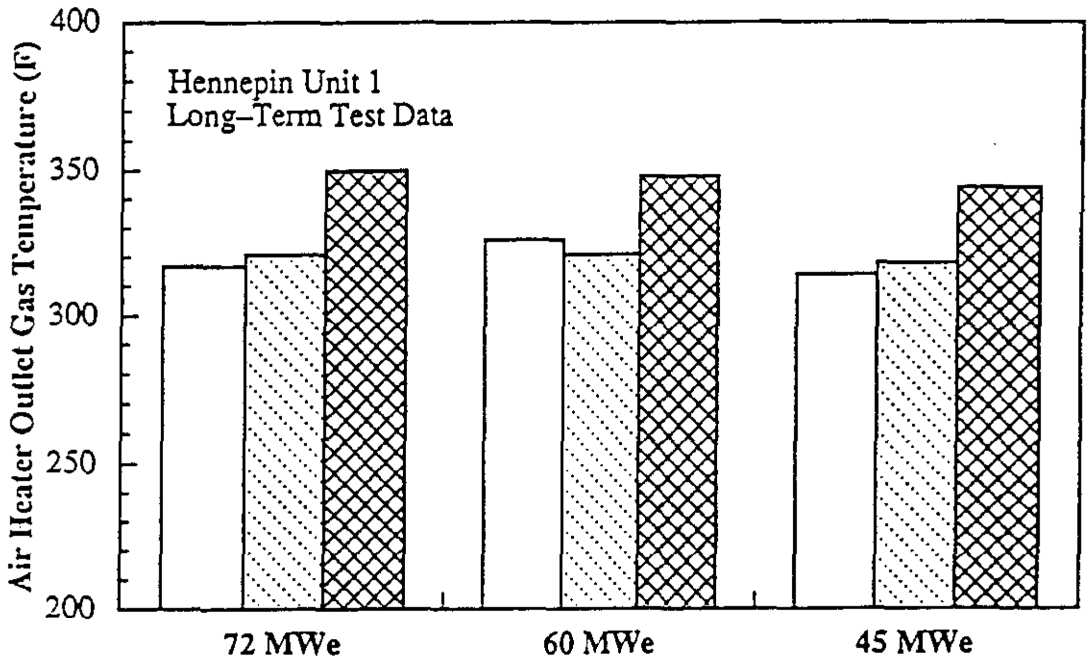


Figure 5-26b Impact of Long-Term testing on air heater outlet gas temperature

The BPMS temperatures indicate a temperature increase throughout the boiler with GR–SI in comparison to baseline temperatures. The temperature increase at the economizer inlet, under GR-SI varied from 42°F (23°C) at 72 MW_e to 38°F (21°C) at 45 MW_e. The economizer inlet was selected as the location to evaluate gas temperature changes due to the presence of a 12-thermocouple grid; other locations had only a single thermocouple.

The increase in economizer inlet gas temperature was not observed during GR operation since no convective pass fouling took place. A slight reduction in economizer inlet gas temperature (4°F [2°C]) during GR operation was measured.

GR-SI also resulted in a moderate increase in the air heater gas outlet temperature. Under baseline operation, the air heater gas outlet temperature ranged from 314°F (157°C) at 45 MW_e, to 317°F (158°C) at 72 MW_e. During GR-SI the air heater outlet gas temperature increased by approximately 30°F (17°C), from 344°F (173°C) at 45 MW_e to 350°F (177°C) at 72 MW_e. GR operation had virtually no impact on air heater gas outlet temperature; over the load range the temperatures were 318°F (159°C) to 321°F (161°C). These data are compared in Figure 5-26b.

A reduction in thermal efficiency was calculated for GR and GR-SI operation using ASME Power Test Code 4.1 (heat loss method). The reduction due to GR-SI was more significant than under GR operation. At full load, the thermal efficiency decreased from a baseline of 86.76% to 86.00% under GR, a reduction of 0.76%, and to 85.38% under GR-SI, a reduction of 1.38%. These were due to changes in three sources of heat loss: dry gas heat loss, moisture in fuel heat loss, and heat loss due to moisture from combustion. The decrease in heat absorption and the resulting rise in the flue gas temperature increase the dry gas heat loss - especially for GR-SI operation. Fuel switching, i.e. replacement of coal heat with heat from natural gas, results in a reduction in the fuel moisture heat loss. Since natural gas has a higher hydrogen to carbon ratio than coal, its combustion results in formation of more moisture and consequently higher moisture from combustion heat loss.

The largest change in thermal efficiency was due to the increase in moisture from combustion heat loss. GR and GR-SI operation with approximately 18% gas heat resulted in combustion moisture heat losses 5.05 and 5.15%, respectively. These may be compared to a combustion moisture heat loss of 3.89% from 100% coal firing. Fuel moisture heat loss during GR and GR-SI operation decreased, from a baseline of 1.74% to 1.45%. As stated, the dry gas heat loss increased during GR-SI operation, from a baseline of 5.29% to 5.78%. GR and GR-SI operation resulted in small reductions in ash combustible matter heat loss, 0.39 to 0.41% compared to 0.5% for baseline, while the radiation losses were the same. These results are summarized in the Table 5-9a. Figure 5-27 shows the thermal efficiencies at low, mid and high loads. In general, the unit was able to generate the necessary power albeit with a slightly lower efficiency.

TABLE 5-9a. HEAT LOSS COMPARISON.

	Baseline	GR	GR-SI
Dry Gas Loss (%)	5.29	5.27	5.78
Moisture in Fuel Loss (%)	1.74	1.45	1.45
Moisture from Combustion Loss (%)	3.89	5.05	5.15
Combustible in Refuse Loss (%)	0.50	0.39	0.33
Radiation & Unmeasured Losses (%)	1.88	1.88	1.88
Total Losses (%)	13.25	13.99	14.62
Thermal Efficiency (%)	86.76	86.00	85.38

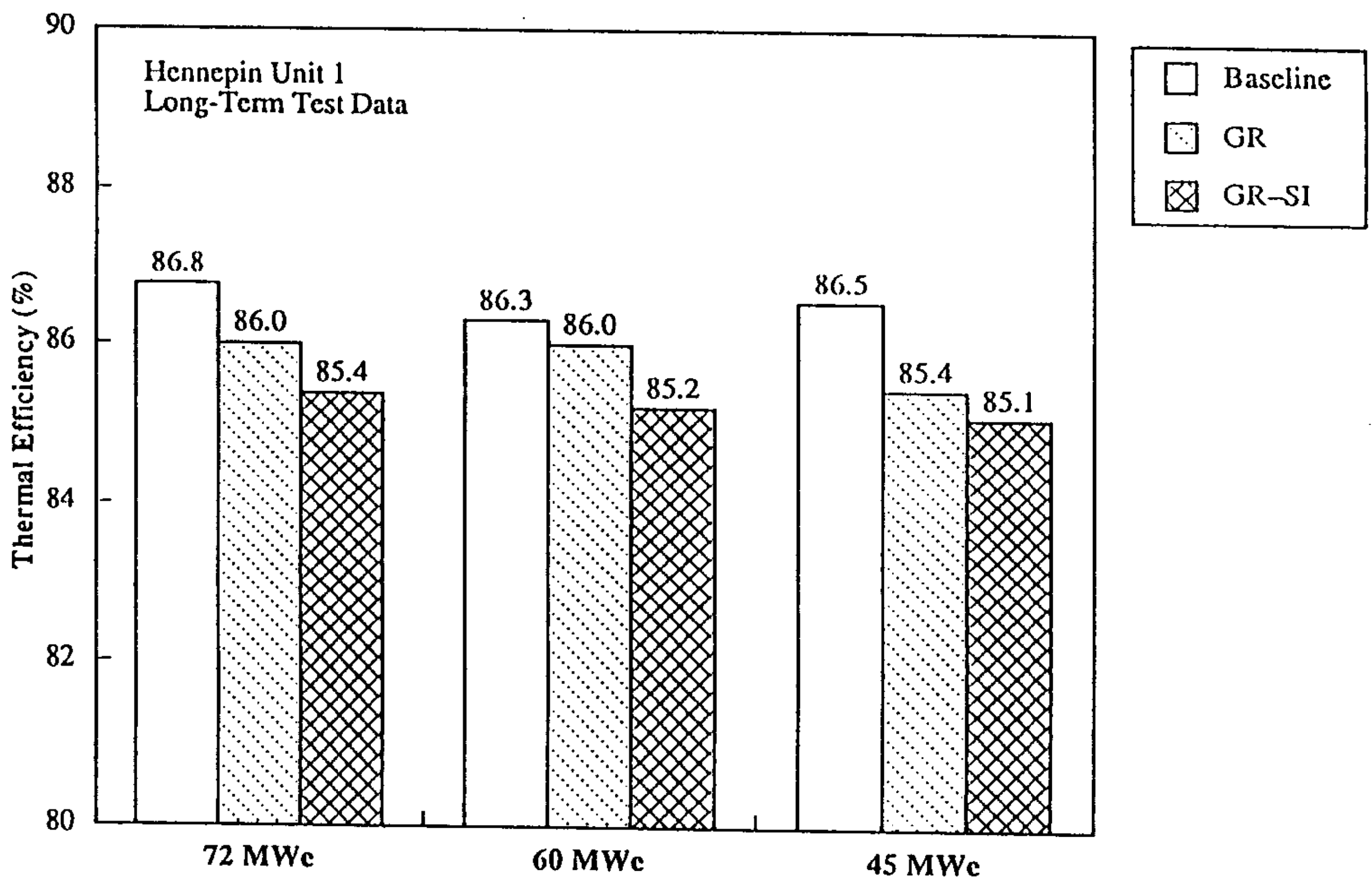


Figure 5-27. Thermal efficiency during Long-Term Testing

A common parameter used to quantify Hennepin Unit 1 performance is the net heat rate. The design net heat rate for Hennepin Unit No. 1 is 10,338 Btu/kWh (10,908 kJ/kWh) at 75 MW_e.

During long-term testing, the baseline net heat rate averaged 10,340 Btu/kWh (10,910 kJ/kWh) at 72 MW_e.

The net heat rate under baseline, GR, SI and GR–SI operation are compared in Figure 5-28. During GR, the net heat rate increased by 88 Btu/kWh to 279 Btu/kWh (93 to 294 kJ/kWh), over the load range. The heat rate increase at full load was 0.85% of the baseline while at 45 MW_e it was 2.67%. During GR–SI operation, the net heat rate increased by 169 Btu/kWh to 260 Btu/kWh (178 to 274 kJ/kWh). At full load, the net heat rate increased by 1.63% and at 45 MW_e by 2.48%. The increase in heat rate under GR and GR-SI operation is a reflection of changes in boiler thermal efficiency, steam temperatures, attemperation flow rates, and auxiliary power.

The retrofit of the GR–SI system to Hennepin Unit 1 required attention be given to several areas of unit operation. Among these was sootblowing, used to maintain heat transfer surfaces free of sorbent and ash deposits. Figure 5-29 shows that the use of sootblowers at 72 MW_e increased from 7% of the time during baseline operation to 36% of the operating time during GR–SI operation. GR-SI resulted in an increase in sootblowing over the range of loads with a minimum of 21% of the time at 45 MW_e, compared to a maximum of 14% during baseline operation.

5.1.6 Impacts of GR, SI and GR-SI on Other Areas of Boiler Operation

In this section the impacts of the co-application of GR and SI on boiler performance areas other than heat transfer efficiency are discussed. These include furnace slagging, convective pass fouling, and ESP performance.

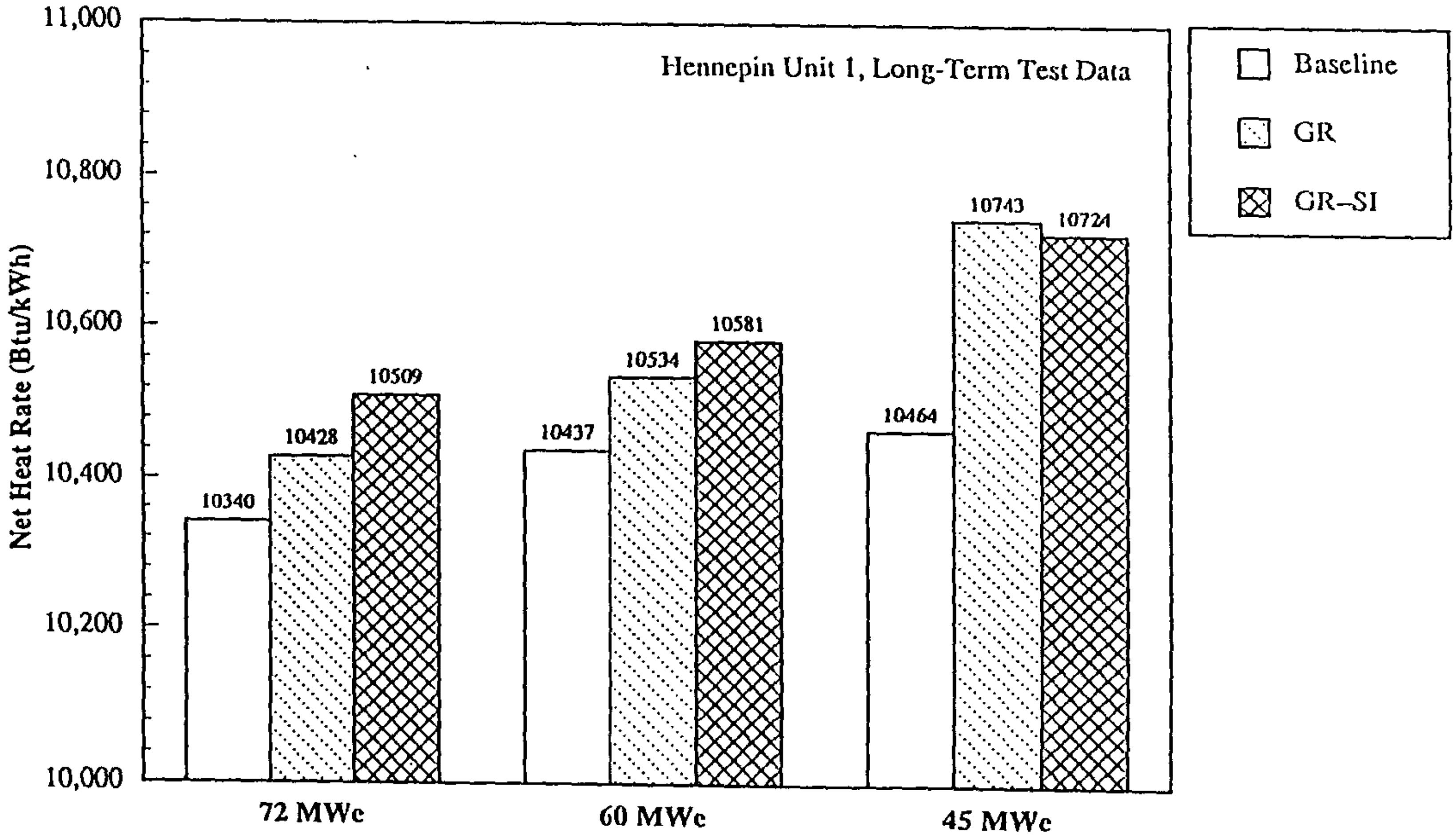


Figure 5–28. Impact of GR, SI and GR-SI on net unit heat rate

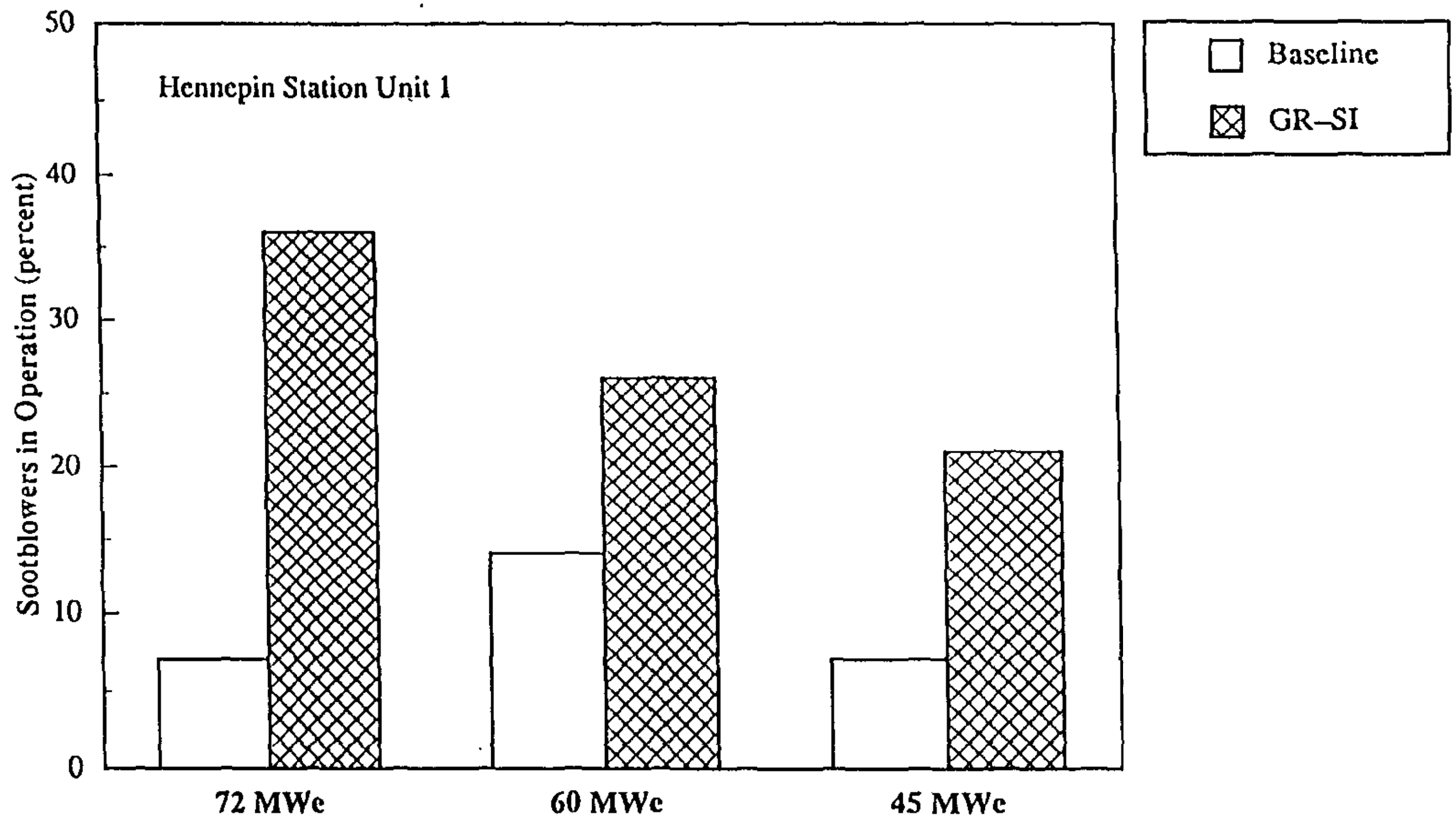


Figure 5-29. Sootblower usage during Long–Term GR-SI testing

In order to assess the impact of gas GR-SI on the boiler, a series of inspections were performed both prior to and following the GR-SI testing. EER established the baseline condition of the unit and determined the existence and rate of both degradation and equipment failures. The following areas were evaluated:

- Boiler tubes
- Electrostatic precipitator
- Chimney
- Boiler performance

5.1.6.1 Slagging

GR-SI operation did not exacerbate slagging in the furnace. Some buildup of slag in the lower furnace, from the top burner elevation to the OFA ports, was observed, but it was not excessive compared to that under baseline operation. Under full load GR-SI over a period of three hours, slag buildup of up to 2 1/2 inches (6 cm) was measured in the lower furnace. This may be compared to buildup of 1 to 3 inches (2.5 to 7.5 cm) at the furnace nose and 3 to 6 inches (7.5 to 15 cm) at the elevation of the wallblowers, observed after day-long baseline operation at full load. Wallblowing more frequently or with greater effectiveness (i.e. higher pressure) has been recommended to reduce slag buildup and to maintain clean GR injection nozzles during future operation.

During the long-term GR-SI demonstration at Hennepin Unit 1, there were several opportunities to inspect the furnace slagging patterns. These inspections focused on determining the extent of slagging while operating GR-SI and checking for signs of excessive tubewall wastage.

Specific areas of the boiler which were identified as potential problems areas for increased slagging under GR-SI operation were closely monitored during the test program due to the following concerns:

- The slightly lower primary zone stoichiometric ratios and resulting higher gas temperature in that zone could exacerbate slagging in the lower furnace

- The reducing conditions in the reburning zone could promote slagging in this zone.

The ash deposition patterns during Baseline, GR, GR-SI operation were comparable. During the 1988 baseline tests, baseline deposition patterns were observed and recorded during normal coal firing. The thickness of deposits varied with the furnace height, from 3 to 6 inches (8 to 15 cm) at the elevation of the wallblowers, to 1 inch (2.5 cm) at the economizer elevation. The phase progression of the ash along the furnace walls was typically wet (i.e. not hardened) to molten to dry.

A thorough observation of furnace deposition patterns was performed on 25 March, 1992 after GR-SI operation. The first observation was completed after the boiler had cycled off during the preceding night allowing some ash to shed off the furnace wall tubes. Figure 5-30 shows the deposition patterns which were recorded during the first two hours of GR–SI operation following the nightly off-cycle. Most of the deposits below the nose elevation were small deposits of fine ash particles which most likely consisted of particles with a very low melting point. The small molten particles impinge on the tubes and tend to resolidify as they come in contact with the relatively cooler wall. At the economizer level, there were several scattered accumulations on the east, west, and north walls. The accumulations appeared to have a thickness of 1/2 to 2 inches (1 to 5 cm). Above the nose elevation there appeared to be additional deposits, notably on the north wall, which showed ash deposits of 3 to 4 inches (8 to 10 cm). The south, east, and west walls showed scattered ash deposits, of up to 1 inch (3 cm) in thickness.

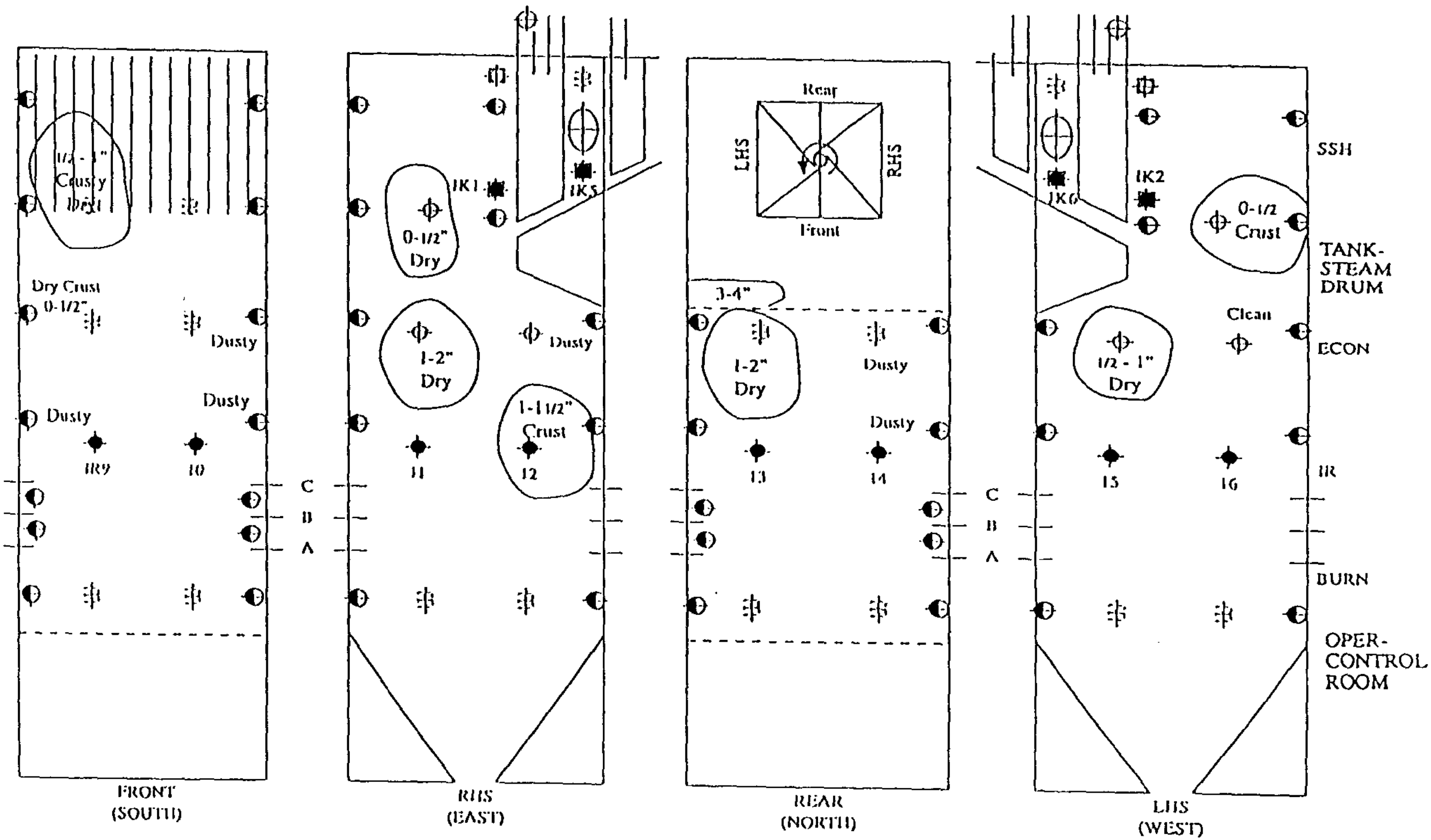


Figure 5-30. Furnace observations at 1130 hours on 25 March 1992

Figure 5-31 shows the deposition pattern observed after 3 hours of additional GR–SI operation. The dusty layers below the nose elevation, which were described earlier, were replaced with wet to crusty deposits of up to 2 1/2 inches (6 cm) in thickness extending from the burner elevation to the OFA elevation. Little change in the upper furnace slagging was observed, in comparison to earlier observations.

Some buildup of slag on GR injectors was observed; however periodic manual cleaning (nominally weekly) was sufficient to maintain normal GR operation. For the most part, the injectors in the southwest and southeast corners were reasonably clean. The injectors in the northwest and northeast corners were at times partially to completely blocked. This was especially the case for the northeast corner injectors. Ash accumulation at the port entrances may be attributed to the tempering caused by the injection of gas and FGR and the fuel-rich conditions in the reburning zone. Slag buildup on specific locations may be due to local air deficiency, optimum temperature for molten slag formation, or poor cleaning by wallblowers in that region. Blockage of gas injectors may affect the heat distribution in the furnace, and the mixing of the natural gas with the primary combustion products which can influence GR operation. Therefore, routine cleaning on a weekly basis (or as required) was adopted. During normal GR–SI operation, no unusual slagging in the area in and around the OFA penetrations was observed. An April 1992 inspection of the OFA ports, conducted immediately following 6 months of GR–SI operation, showed minor ash buildup in all of the port entrances. Some blockage occurred when the ports were out of service for extended periods. Observations made after 3 months of coal-only operation, with only cooling air supplied to the OFA ports, revealed some slag buildup around port entrances. The worst slag buildup blocked approximately 40% of the port in the northwest corner. Therefore, the ports should be cleaned after periods when the GR system is out of service.

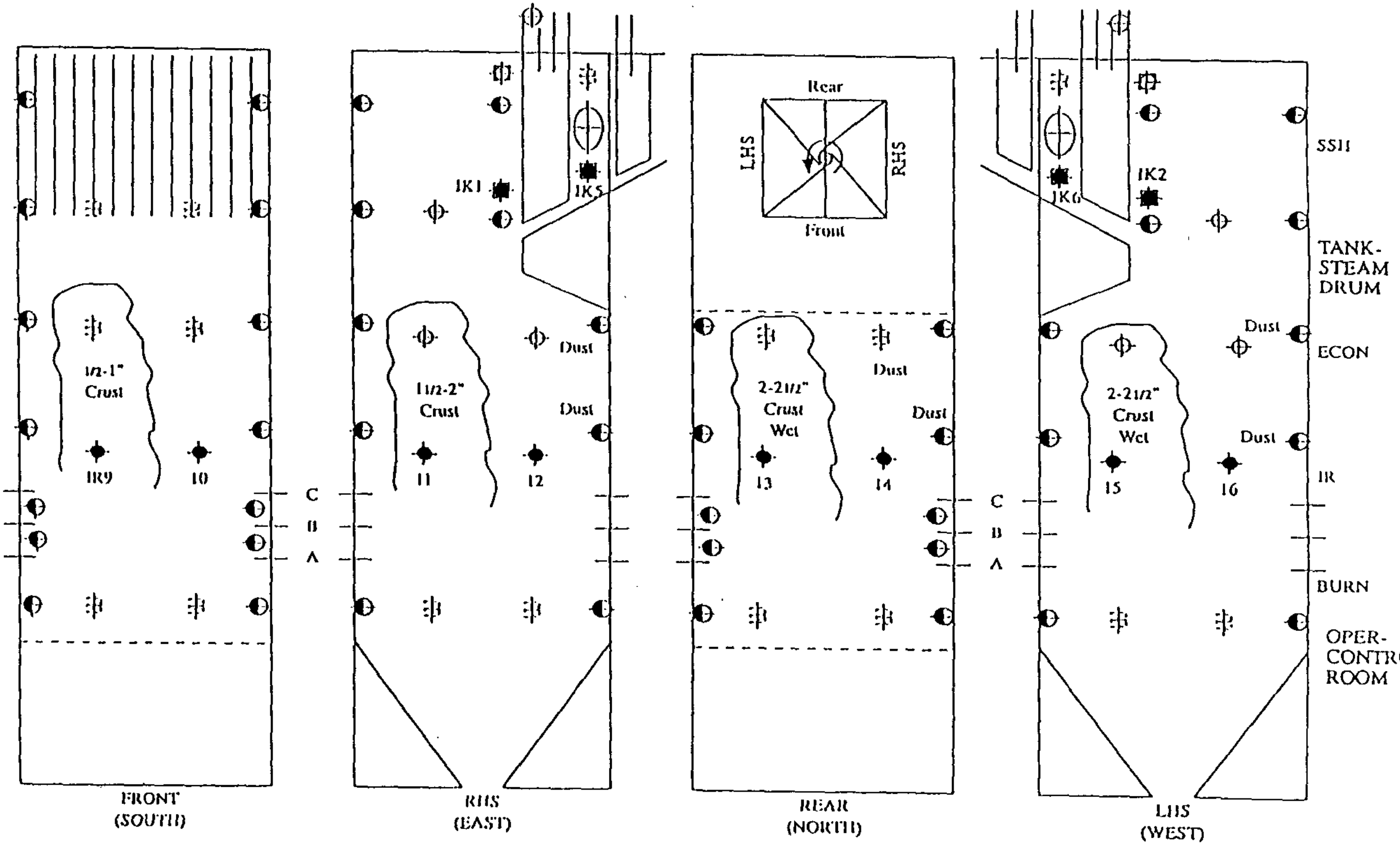
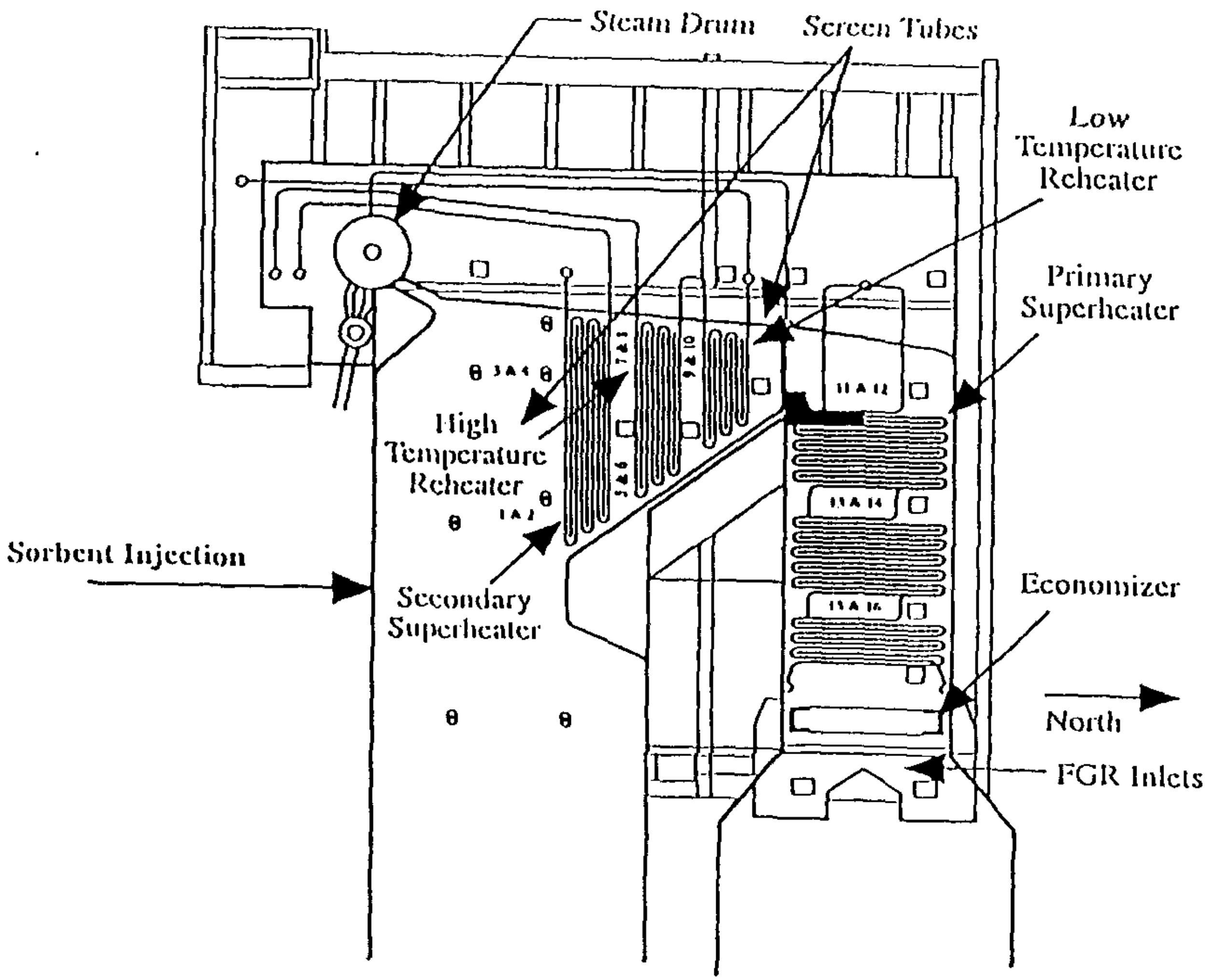


Figure 5-31. Furnace observations at 1430 hours on 25 March 1992

5.1.6.2 Convection Pass Fouling

SI increased the particulate loading in the convective pass. Ash deposition increased and sootblower operating time increased correspondingly to control the buildup. A visual inspection of the convection sections in March 1992 showed no evidence of scouring from sorbent erosion or from sootblower operation. Some accumulations were noted, particularly on the top surface of the primary superheater. To reduce the amount of accumulated material in this area, IK sootblowers Nos. 11 and 12 were used twice per shift. After two days, another inspection showed that much of the accumulation had been removed. Some evidence suggests that large chunks of hard ash deposits broke off the edges of the reheater and became lodged between the tube elements and along the leading edges of the primary superheater which initiate the accumulations. This kind of ash accumulation has been reported from baseline operation also. Figure 5-32 shows the convective pass arrangement for reference.

Cleanliness factors (CF) were calculated continuously during GR-SI testing to quantify the extent of fouling of convective pass heat exchangers. The cleanliness factors are ratios of the actual heat transfer coefficients (i.e. under GR-SI) to those under baseline operation. The heat transfer coefficient of each heat exchanger is the ratio of heat absorbed to the product of the heat exchanger surface area and the log mean temperature differential. A cleanliness factor above 1.0 indicates a relatively clean surface and cleanliness factors below 1.0 indicate surface fouling. This section presents the cleanliness factor data associated with the secondary superheater, reheater, and primary superheater during GR-SI operation and compares these with a baseline case. Another parameter used to evaluate heat absorption is the Heat Absorption Ratio (HAR), which is the ratio of the heat absorbed by the heat exchanger under GR-SI operation to that absorbed during baseline operation at the same load. Also presented are the operating parameters which impact heat absorption by the heat exchangers in the convective pass, including sorbent flow rate, burner tilt angle, and sootblower operation. The CF and HAR of the other heat exchangers (furnace, economizer, air heater) are not considered, since heat transfer in the furnace is



Note: 1 through 16 designates IK sootblower locations

Figure 5-32. Convection Pass Fouling Locations primarily by radiation, the temperature drop at the economizer is too small to yield consistent results, and air heater heat transfer is impacted by air leakage. The CF during baseline operation are shown in Figure 5-33. The data show that CF for the secondary superheater, reheater and primary superheater are held in a narrow range over several hours of baseline operation. Slight degradations of secondary superheat and reheat CF with time is evident, necessitating use of sootblowers. Sootblowing quickly improved the CF to unity.

The impacts of GR-SI operation on the heat transfer to the three heat exchangers are evident in two cases, considered in Figure 5-33 through 5-37. Both cases show several hours of GR-SI operation at full load, with sorbent flows of 5,000 to 8,800 lb/hr (0.63 to 1.11 kg/s). Both cases exhibit similar trends. SI results in fouling of each heat exchanger, as indicated by reduction in CF, but sootblowing effectively cleaned the secondary superheater and reheater, restoring the CF back to unity. The heat absorption of the secondary superheater was below the baseline level (i.e. HAR under 1.0), but reheat heat absorption was essentially unchanged and the primary superheat heat absorption increased over the baseline level.

A cyclic pattern resulted from sorbent fouling, coal burner tilt movement, and sootblowing. At full load, the coal burners were initially tilted downward. SI resulted in fouling of the secondary superheater and reheater, indicated by reductions in CF, resulting in an upward shift of the burners tilts. Superheater fouling triggers sootblowing, which cleans the secondary superheat and reheater surfaces and leads to a downward shift in coal burner tilts. The CF of the secondary and reheat superheaters were restored to unity (baseline level) by sootblowing. The HAR for these heat exchangers show similar fluctuations. The HAR for the secondary superheater varied most widely, but was generally below unity. The reheat HAR was held fairly constant. The primary superheater HAR was significantly above unity during the fouling of the upstream heat exchangers, which resulted in higher gas temperature at the primary superheater. Figures 5-35 and 5-37 show that the

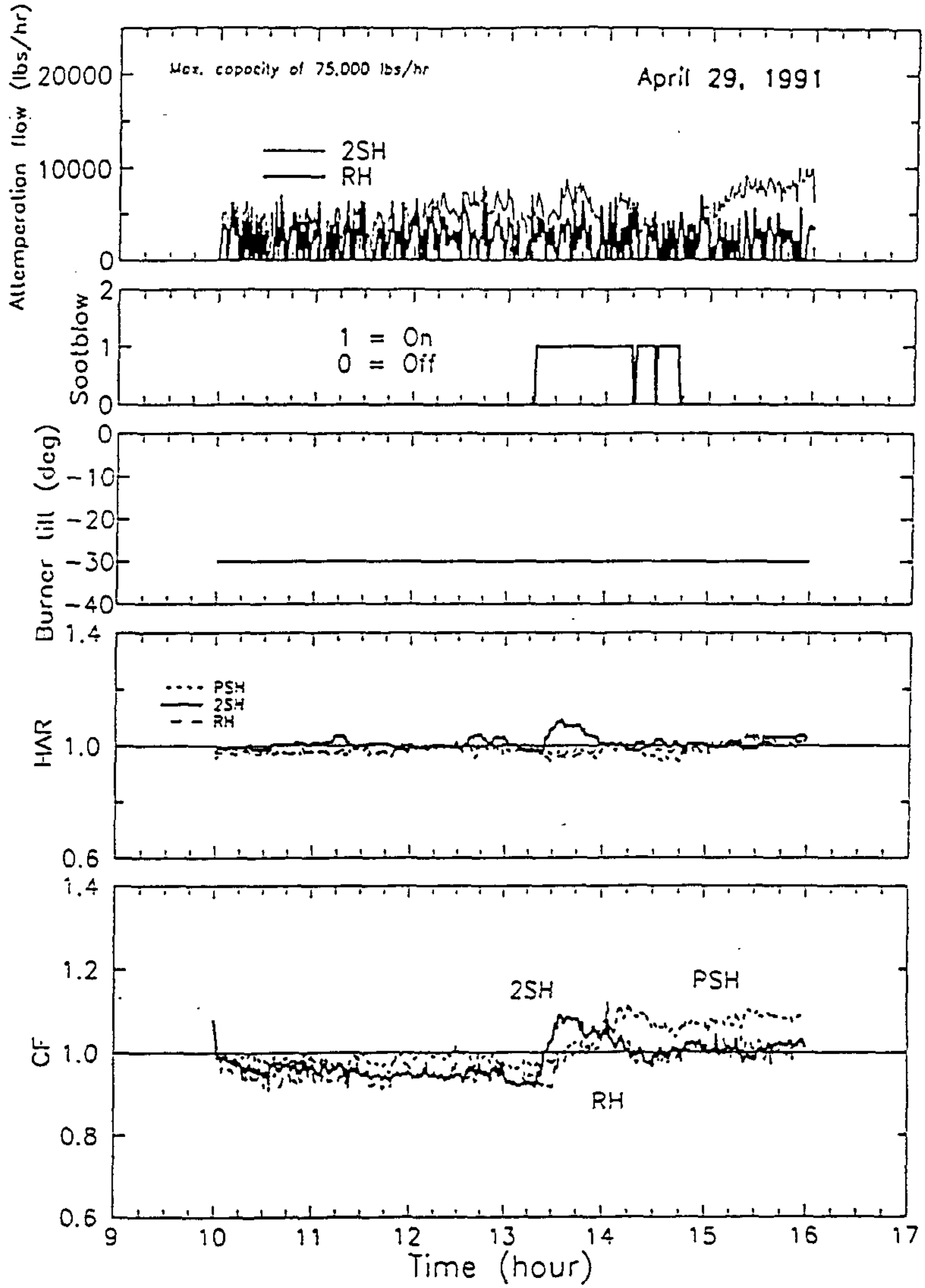


Figure 5-33. Cleanliness factors (CF) and heat absorption ratios (HAR) during baseline operation

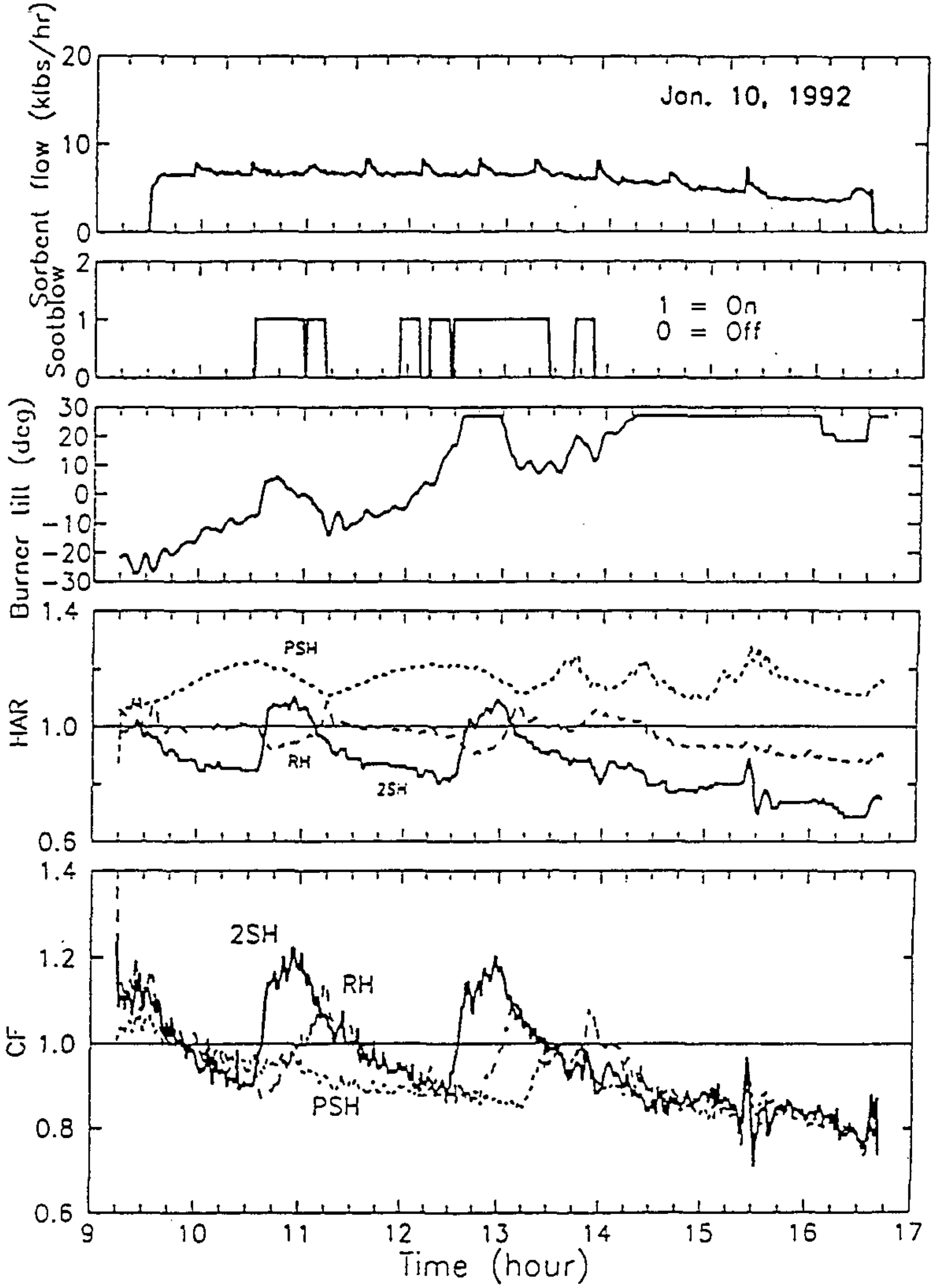


Figure 5-34. Cleanliness factors (CF) and heat absorption ratios (HAR) during GR-SI operation (case 1)

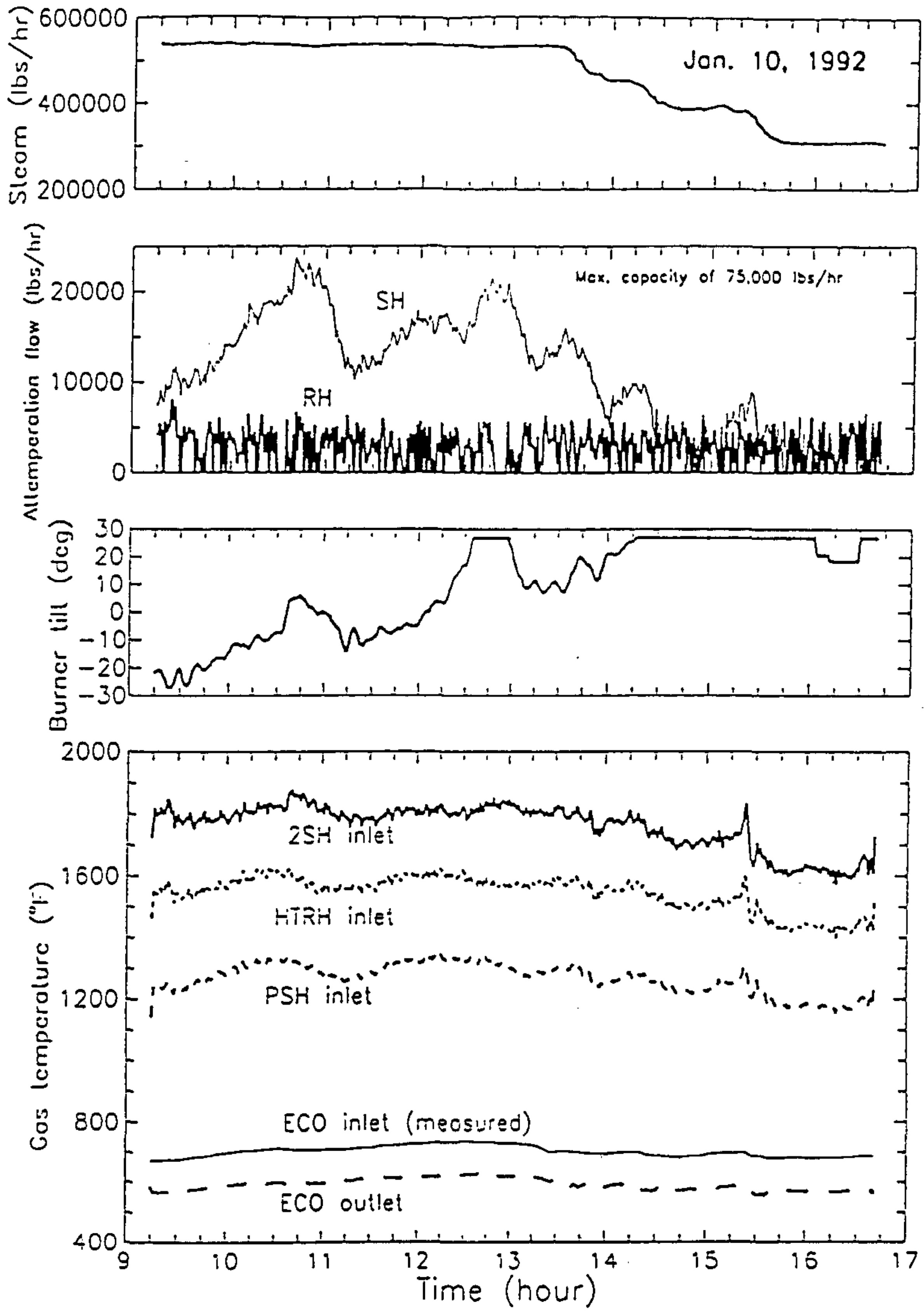


Figure 5-35. Mean Gas Temperature distribution (case 1)

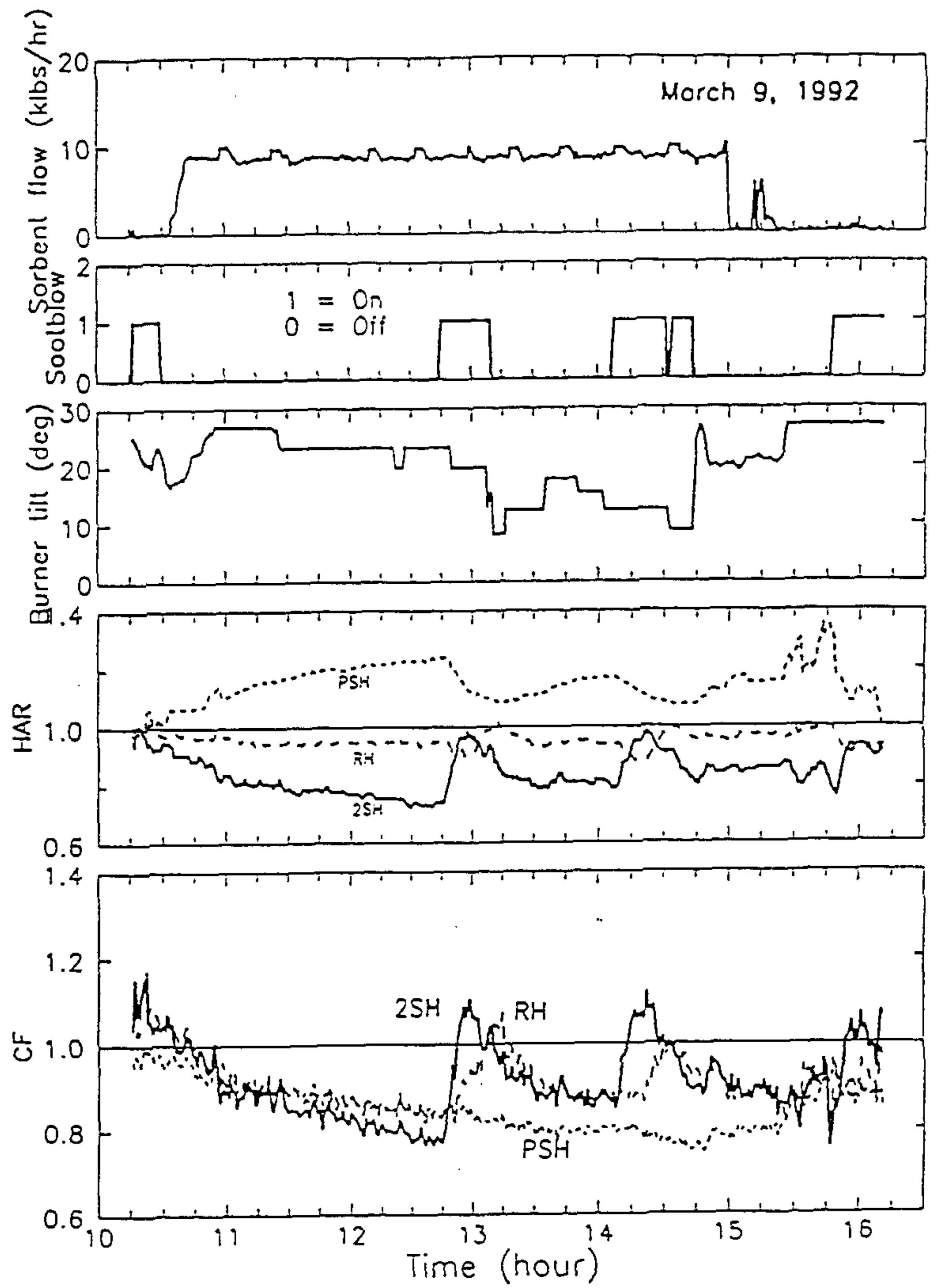


Figure 5-36. Cleanliness factors (CF) and heat absorption ratios (HAR) during GR-SI operation (case 2)

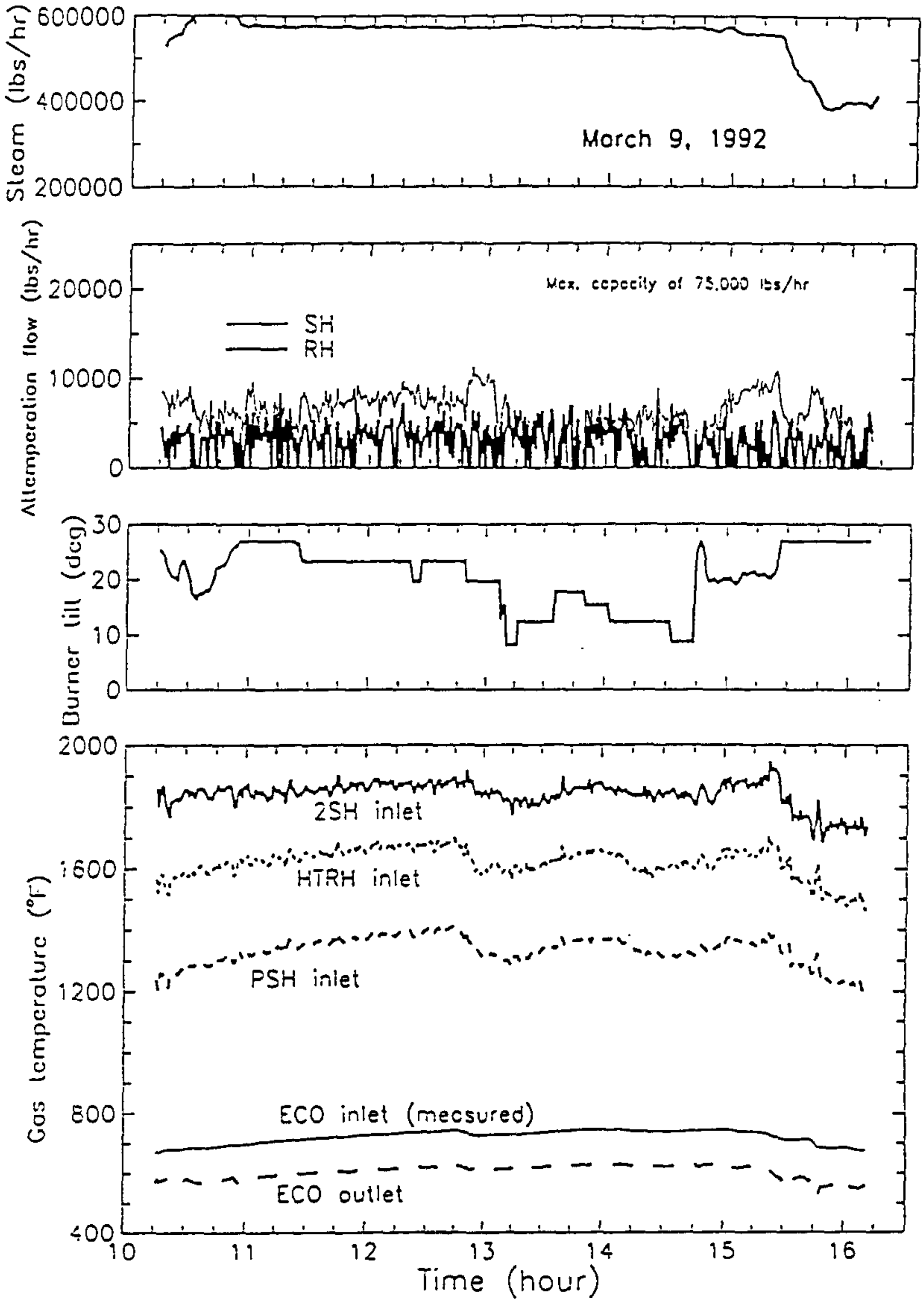


Figure 5-37. Mean Gas Temperature distribution (case 2)

superheater attemperation flow varied with burner tilt position, but was still far below its capacity. Similar shifts in the gas temperature profiles, with burner tilt fluctuations, are also evident.

5.1.6.3 ESP Performance

A summary of the ESP particulate loading test data is shown in Table 5-10 for the April and August/September 1992 ESP characterization tests. The particulate tests were conducted using EPA Method 17 at the ESP inlet and Method 5 at the ESP outlet duct. Hennepin Unit 1 is limited to particulate matter emissions of 0.1 $lb/10^6Btu$ (43 mg/MJ), which corresponds to an hourly limit of 76 lb (34 kg) at 70 MW_e. Electrostatic precipitator performance was evaluated during baseline, GR and GR-SI operation. The overall mass collection efficiency of the ESP ranged from 99.48 to 99.95%. During full load baseline operation, particulate emissions ranged from 0.018 to 0.035 $lb/10^6Btu$ (7.7 to 15.1 mg/MJ), while during full load GR the range was 0.025 to 0.033 $lb/10^6Btu$ (10.8 to 14.1 mg/MJ) and during full load GR-SI the range was 0.015 to 0.025 $lb/10^6Btu$ (6.5 to 10.8 mg/MJ). Humidification, used during SI operation, effectively limited particulate emissions to baseline levels. The mechanisms for ESP enhancement by humidification, was by reduction in the flue gas temperature thereby reducing fly ash resistivity and increasing the Specific Collection Area (SCA). Under SI the fly ash/sorbent mixture may have a resistivity two orders of magnitude higher than normal fly ash due to reduction in SO_3 concentration and increase in CaO (Case, 1985; Gartell, 1973).

Under normal short-term GR-SI operation with humidification, ESP performance was adequate to maintain particulate emissions below 0.1 $lb/10^6Btu$ (43 mg/MJ) and stack opacity levels below the 30% limit. However, the increased fouling during extended GR-SI operation at full load increased the boiler exhaust temperature beyond the capabilities of the humidification system. As a result, the stack opacity increased over time. This was usually not a problem since Hennepin Unit 1 operates in cycling

TABLE 5-10. SUMMARY OF ESP PERFORMANCE DATA

Date 1992	Run #	Boiler Load (MWe)	Coal Flow (lb/min)	Gas Heat (%)	Ca/S Molar Ratio	Humid H_2O (gpm)	ESP Inlet Loading (lb/hr)	ESP Inlet Gas Flow (dscfm)	ESP Inlet Partic. Conc. (gr/dscf)	ESP Outlet Loading (lb/hr)	ESP Outlet Gas Flow (dscfm)	ESP Outlet Partic. Conc. (gr/dscf)	ESP Outlet Emission (lb/MBtu)	SCA (ft^2 /1000 acfm)	ESP Collection Efficiency (%)
13-Apr	1	70-GRSI	969	19.1	1.89	25.1	12,003	169,824	8.246	11.49	175,483	0.008	0.015	267	99.90
13-Apr	2	70-GRSI	971	19.0	1.87	27.6	8,957	171,702	6.086	16.34	182,442	0.010	0.021	259	99.82
14-Apr	1	60-GRSI	817	18.9	1.85	24.0	8,802	154,774	6.635	10.80	157,539	0.008	0.017	294	99.88
14-Apr	2	60-GRSI	826	18.6	1.78	29.0	10,832	159,213	7.937	13.40	162,307	0.010	0.021	286	99.88
15-Apr	1	70-GR	962	19.2	0	0.0	5,152	174,307	3.449	22.09	184,174	0.014	0.029	245	99.57
15-Apr	2	70-GR	962	19.0	0	0.0	5,111	184,444	3.233	18.62	189,905	0.011	0.025	232	99.64
16-Apr	1	45-GRSI	622	18.6	1.81	15.7	3,928	121,427	3.774	6.45	123,695	0.006	0.013	380	99.84
16-Apr	2	45-GRSI	634	18.3	1.79	21.6	4,571	120,891	4.411	6.02	129,095	0.005	0.012	370	99.87
17-Apr	1	70-Base	1167	0.0	0	0.0	6,845	169,014	4.725	13.04	178,952	0.009	0.018	251	99.81
17-Apr	2	70-Base	1168	0.0	0	0.0	5,405	167,864	3.756	16.34	184,509	0.010	0.022	249	99.70
26-Aug	1	45-GRSI	626	18.7	1.66	20.9	5,591	134,382	4.855	10.66	113,163	0.011	0.022	376	99.81
26-Aug	2	45-GRSI	626	18.7	1.66	20.9	5,382	132,116	4.753	2.75	117,334	0.003	0.006	368	99.95
27-Aug	1	60-GRSI	828	18.6	1.64	22.7	8,604	138,758	7.235	12.53	155,423	0.009	0.019	311	99.85
27-Aug	2	60-GRSI	826	18.6	1.64	22.7	7,810	142,615	6.390	10.89	153,547	0.008	0.017	311	99.86
28-Aug	1	60-GR	1171	18.7	0	0.0	7,425	138,236	6.268	10.62	151,162	0.008	0.016	300	99.86
31-Aug	1	70-Base	1171	0.0	0	0.0	7,562	171,351	5.149	21.28	178,405	0.014	0.028	248	99.72
31-Aug	2	70-Base	948	0.0	0	0.0	6,286	170,083	4.312	26.22	188,180	0.016	0.035	241	99.58
1-Sep	1	70-GR	948	19.0	0	0.0	5,120	158,883	3.760	19.80	180,642	0.013	0.027	255	99.61
1-Sep	2	70-GR	964	19.0	0	0.0	4,685	165,563	3.302	24.20	186,302	0.015	0.033	245	99.48
2-Sep	1	70-GRSI	964	18.7	1.71	24.9	8,183	167,188	5.711	18.62	181,596	0.012	0.025	261	99.77
2-Sep	2	70-GRSI	964	18.7	1.71	24.9	8,966	165,055	6.339	15.58	179,694	0.010	0.021	262	99.83
3-Sep	1	70-GRSI					8,346	169,103	5.759	18.08	185,797	0.011	0.024	255	99.78

dscfm: dry standard cubic feet per minute
gr/dscf: grains per dry standard cubic foot

service. ESP performance was satisfactory during a 55 hour long-term GR-SI test at reduced load. Operation was limited to 32 hours at full load.

Data were taken to compare ash characteristics that are believed to effect ESP performance. These include particulate matter size and loading, fly ash resistivity, ESP inlet gas temperature distribution, and coal mill fineness measurements. In addition, internal and external inspections of the ESP helped to isolate electrical and mechanical problems that may have limited GR-SI operation. See Figures 5-38 through 5-43.

Inspections of the ESP were conducted by contractors to determine condition prior to initiation and after completion of the GR-SI testing.

5.1.6.4 GR-SI System Auxiliary Power

The GR-SI system auxiliary power usage during long-term testing is found in Table 5-11. Data were taken on a monthly basis and are shown with the hours of Baseline,

TABLE 5-11. GR-SI AUXILIARY POWER

Month/Yr	Auxiliary Power (KWH)	Testing Hours Baseline	GR	SI	GR-SI	Total
Jan/92		88,800	161.03	29.28	504.58	244.90
Feb/92	79,200	51.72	8.28	2.53	47.77	110.30
Mar/92	122,400	24.05	18.28	17.72	92.58	152.63
Apr/92	91,200	25.40	19.14	19.17	84.26	147.97
Sept/92	139,200	16.54	6.58	0	124.31	147.43
Oct/92	52,800	1.23	27.72	0	100.13	129.08

GR, SI, and GR-SI operation. These are hours over which emissions data were averaged; therefore, they are lower than the actual hours of the GR-SI system

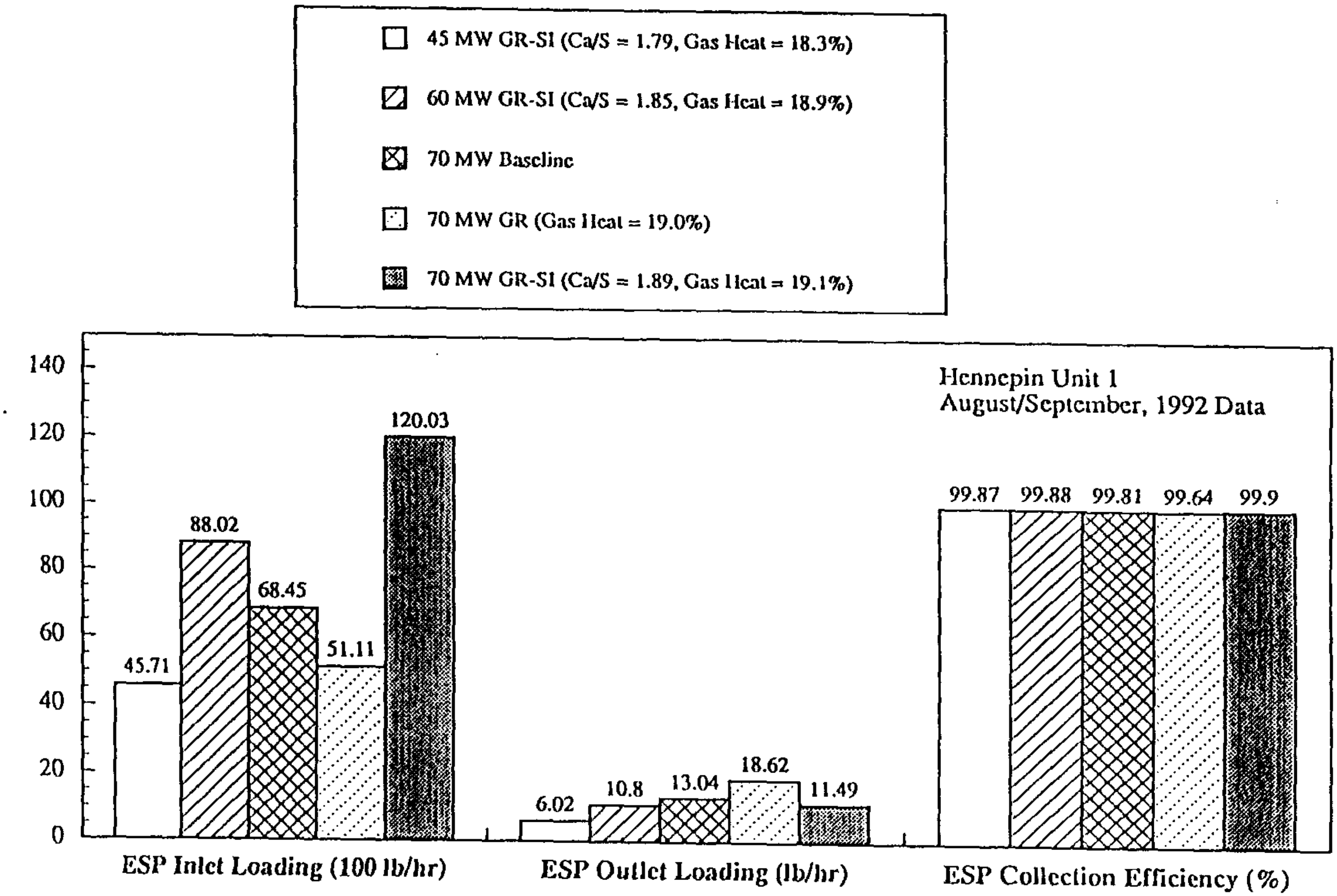


Figure 5-38. Particulate loading at the ESP inlet and outlet and collection efficiency (April, 1992 Data)

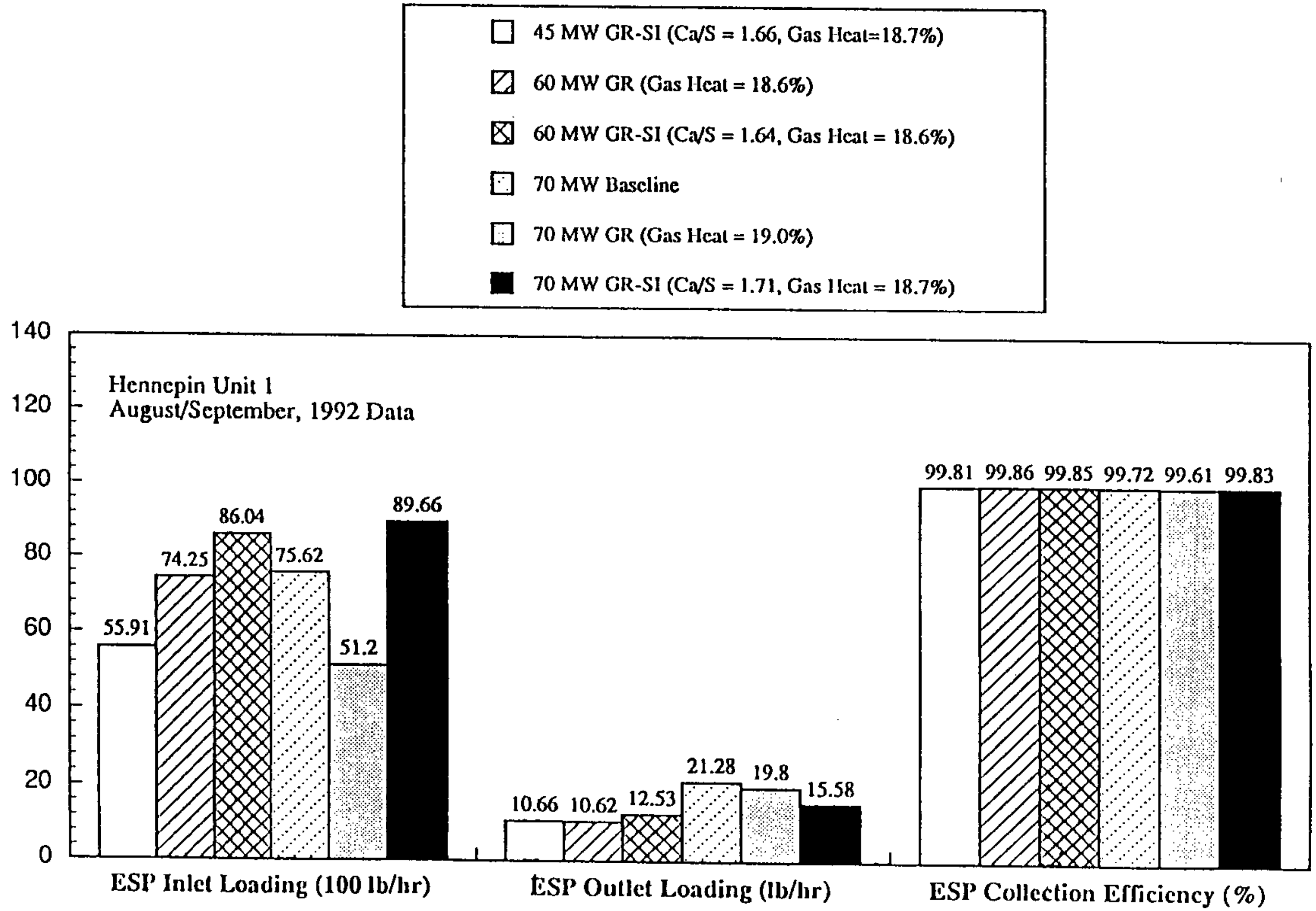


Figure 5-39. Particulate loading at the ESP inlet and outlet and collection efficiency (August/September, 1992 Data)

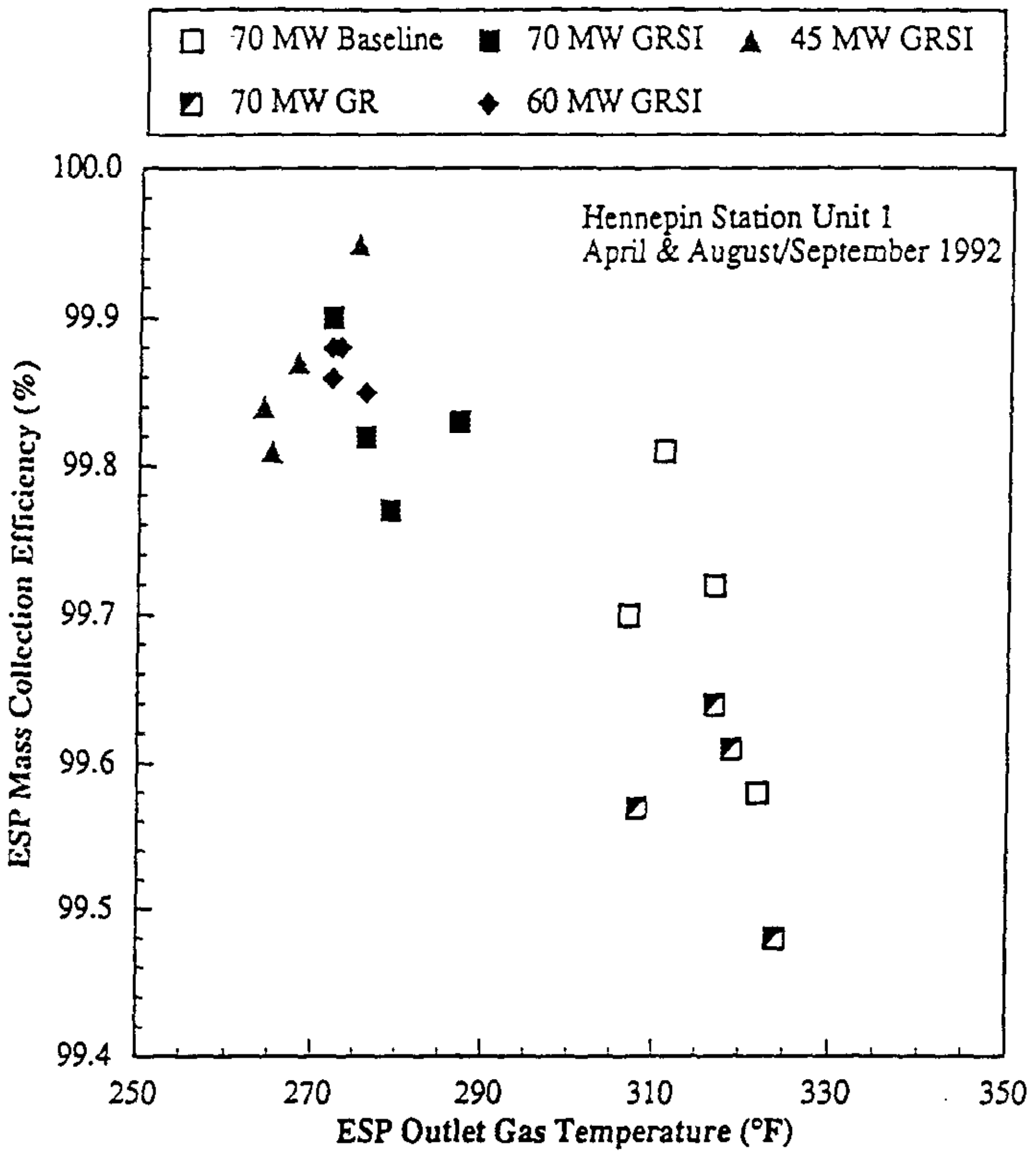


Figure 5-40. ESP mass collection efficiency as a function of flue gas temperature

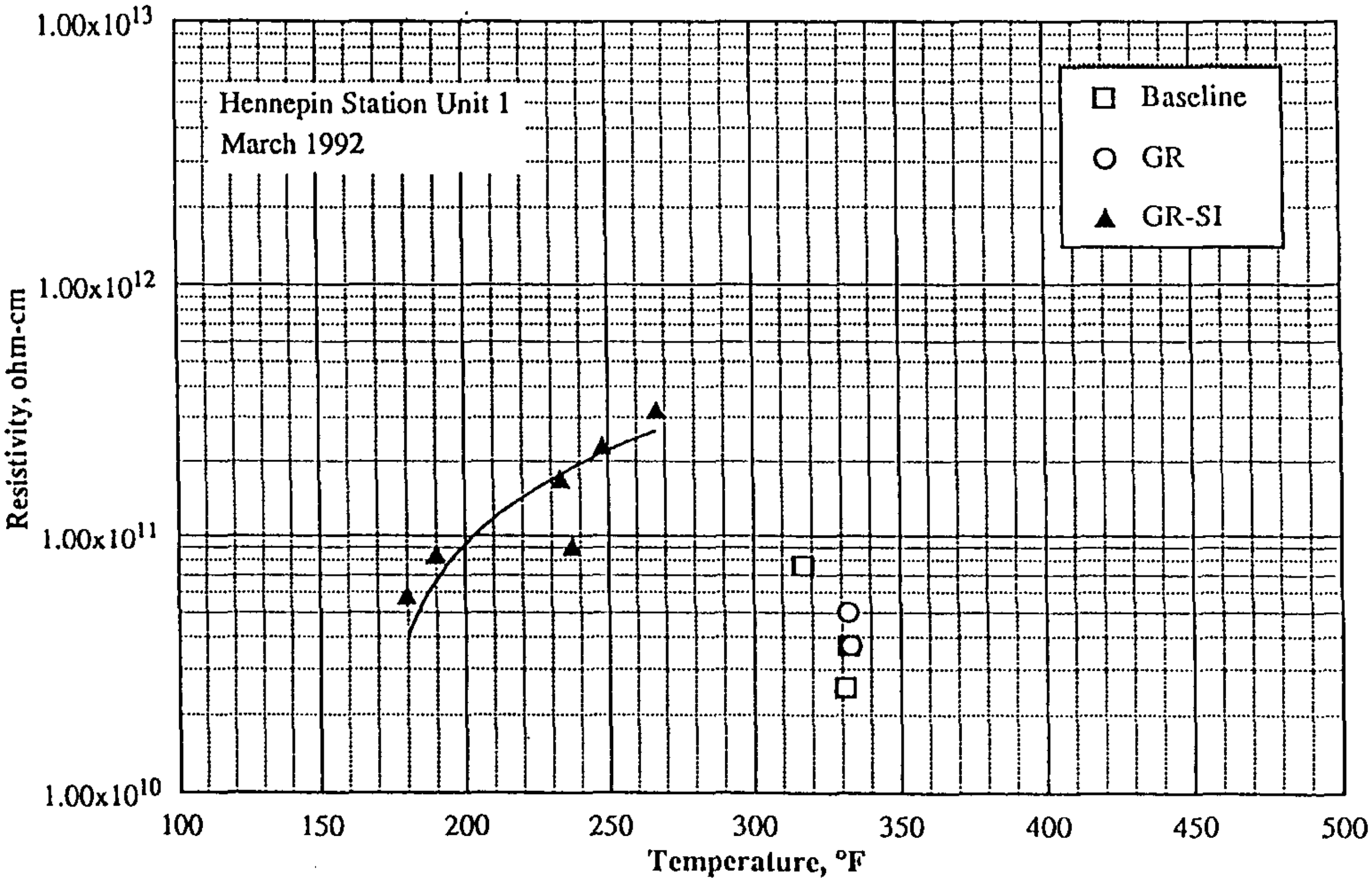
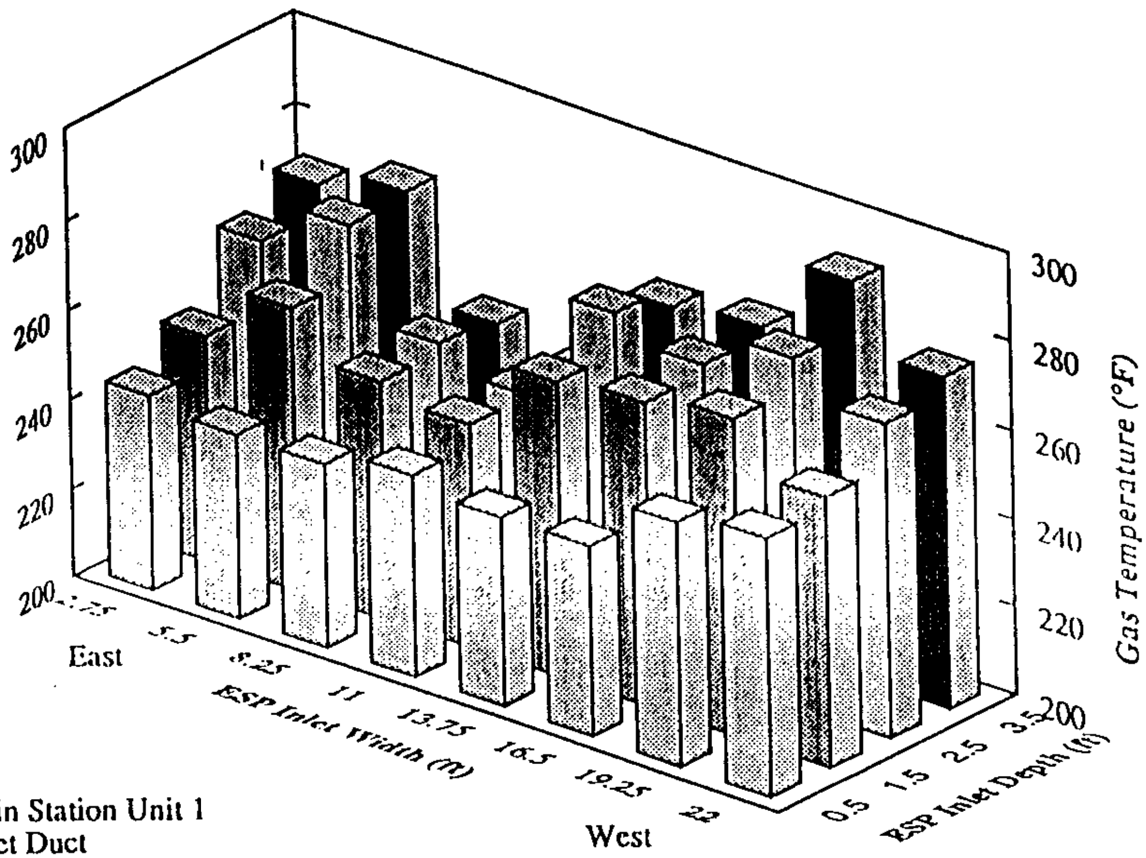
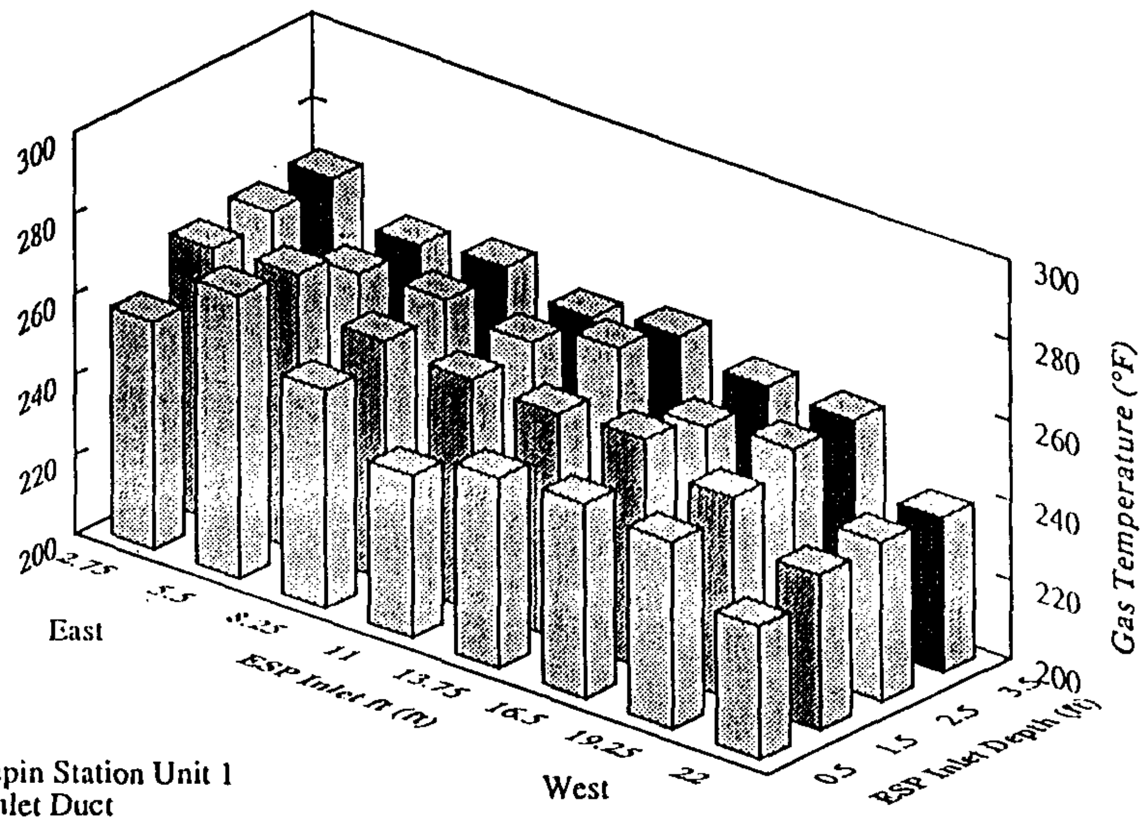


Figure 5-41. In–situ resistivity measurements during sorbent injection by the V–I method



Hennepin Station Unit 1
ESP Inlet Duct
Dimensions: 25' Wide x 4' Deep
GR-SI Operation
Load: 60 MWe
Average Temperature: 262°F
26 August 1992: Run #2

Figure 5-42. ESP inlet duct temperature profile for a 60 MWe test



Hennepin Station Unit 1
ESP Inlet Duct
Dimensions: 25' Wide x 4' Deep
GR-SI Operation
Load: 45 MWe
Average Temperature: 256°F
26 August 1992: Run #1

Figure 5-43. ESP inlet duct temperature profile for a 45 MWe test operation. A fraction of the power metered by the GR-SI system watt-hour meter is used for lighting and other purposes. A maximum power usage of 800 kW was calculated for GR-SI, during the design of the system. GR, SI and GR-SI operation also affect power utilization by other plant equipment. A small reduction in coal mill power and a small increase in ESP power are expected. The changes in power consumption by coal mills, ID and FD fans, and the ESP are considered for three full load tests conducted under baseline, GR, and GR-SI in Table 5-12. Fan power did not change appreciably, but reduction in mill power consumption and increase in ESP power of approximately 10% in each are evident. The total auxiliary power under the different operating modes is shown in Figure 5-44. Total auxiliary power consumed by Hennepin Unit 1 increased by approximately 300 kW, under GR-SI. GR operation resulted in a negligible increase in auxiliary power, while SI resulted in an increase of 100 to 300 kW.

5.1.7 GR-SI Design and Equipment Changes

The final GR-SI system had few changes from the original design. The changes were in the following areas: the reburning fuel injector size, reburning fuel injector tilting, number of humidification nozzles in use, the humidification duct configuration, and sorbent injectors in use. The reburning fuel injectors required modification after they were received from the manufacturer. The nozzles were approximately twice the size specified, requiring modification so that the final design had approximately 75% of the original cross-sectional area. The original design specified tilting capability of the reburning fuel injectors to follow the angle of the coal burners. During the optimization/parametric testing evaluation the tilting of the injectors was found to have little impact on the emissions reduction performance. Therefore, the tilting capability of these injectors was removed and the reburning fuel is injected horizontally.

The humidification system required modification in two areas: the number of nozzles in use and the duct configuration. The humidification duct was originally installed with

TABLE 5-12. PLANT EQUIPMENT POWER CHANGE DUE TO GR AND GR-SI

Condition	Full Load Baseline	Full Load GR	Full Load GR-SI
Date	1/7/92	1/8/92	1/9/92
Gross Load (MWe)	71	72	70
Coal Flow (klb/hr)	68.7	58.4	56.6
Gas Heat Input (%)	0.0	17.9	17.7
Ca/S Molar Ratio	0.00	0.00	1.75
BFP-B (Amps)	360	380	360
BFP Power Change (% of Base)	******	5.6	0.0
ID-1A (Amps)	115	130	130
ID-1B (Amps)	140	140	135
ID Fan Power Change (% of Base)	******	5.9	3.9
FD-1A (Amps)	45	45	45
FD-1B (Amps)	50	55	50
FD Fan Power Change (% of Base)	******	5.3	0.0
A-Mill (Amps)	65	60	60
B-Mill (Amps)	70	65	60
C-Mill (Amps)	65	60	60
Mill Power Change (% of Base)	******	-7.5	-10.0
Precip-A-Primary Current (Amp-AC)	121	124	136
Precip-A-Primary Voltage (Vlt-AC)	381	383	383
Precip-A-Power (kW)	46	47	52
Precip-B-Primary Current (Amp-AC)	105	106	118
Precip-B-Primary Voltage (Vlt-AC)	383	381	383
Precip-B-Power (kW)	40	40	45
Precip-C-Primary Current (Amp-AC)	78	82	87
Precip-C-Primary Voltage (Vlt-AC)	381	383	381
Precip-C-Power (kW)	30	31	33
Precip-D-Primary Current (Amp-AC)	75	82	77
Precip-D-Primary Voltage (Vlt-AC)	383	382	382
Precip-D-Power (kW)	29	31	29
Total Precipitator Power (kW)	145	151	160
Precipitator Power Change (% of base)	******	4.1	10.5

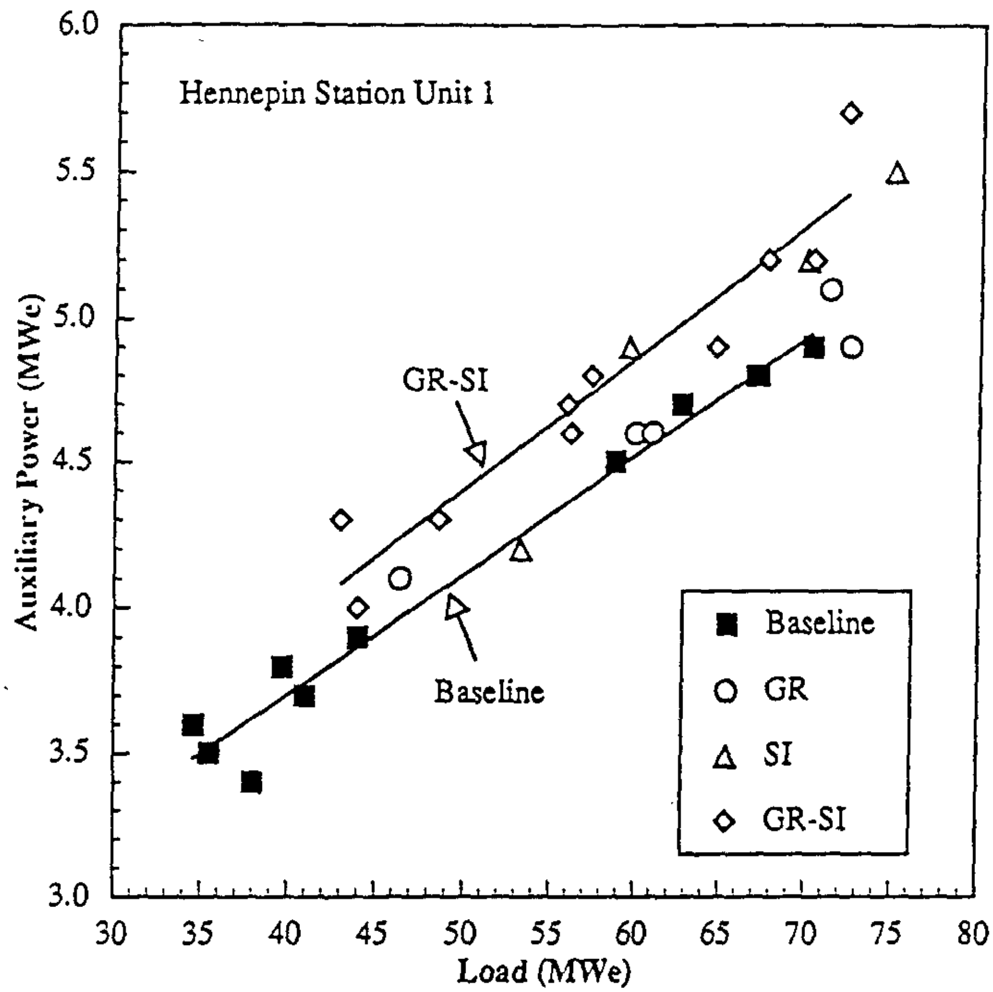


Figure 5-44. Total auxiliary power under GR, SI and GR-SI operation

34 nozzles mounted to six horizontal lances in two parallel ducts. The system was designed to cool the flue gas to 274°F (within 70°F of saturation temperature). In practice, the ESP performance was acceptable at higher reduced temperatures (except for some extended operation). During preliminary testing it was determined that water from the lower two lances (12 nozzles) did not evaporate rapidly enough causing water droplets to enter the ESP. Therefore, the configuration was modified to discontinue use of the two lower lances, thereby injecting the humidification water through 22 nozzles affixed to the upper four lances. However, the actual water flow required for ESP enhancement was maintained.

Several changes to the humidification duct configuration were required to enhance water vaporization and ash collection. These included installation of a perforated plate and turning vanes at the humidification duct entrance, plus two additional hoppers for collection of accumulated ash. One change from the original design was not in the GR-SI system configuration, but in the operation of that system at low loads. The GR-SI system design specified switching of SI from the upper furnace to the OFA port position at 50% load, due to a shift in the furnace gas temperature profile.

5.2 Lakeside

5.2.1 Coal Analyses and Sorbent Composition

Proximate and ultimate analyses of coal fired at the Lakeside Station during Phase I baseline testing and the GR-SI demonstration are compared with a design composition in Table 5-13. The coal fired during the demonstration had a lower heating value, reduced fixed carbon/volatile matter and higher moisture content than that fired previously. The average coal sulfur content of 3.03% and carbon content of 55.75% correspond to a theoretical SO_2 level of 6.01 lb/10^6Btu (2580 mg/MJ) and CO_2 level of 203 lb/10^6Btu (85.3 g/MJ). The coal has a stoichiometric air requirement of 5.58 lb air/lb coal on the basis of 21% O_2 requirement. It is a slagging type coal, i.e. it has

TABLE 5-13. SUMMARY OF PREVIOUS AND CURRENT COAL COMPOSITIONS

Component	Unit	Design Coal	1988 Baseline Testing Average	1991 Baseline Testing Average	1993 - 1994 GR-SI Demonstration Average
Proximate Analysis					
Fixed Carbon	%	43.70	39.38	38.66	38.53
Volatile Matter	%	32.30	34.04	33.62	32.56
Moisture	%	13.70	17.80	17.78	19.24
Ash	%	10.30	8.78	9.94	9.67
Higher Heating Value	Btu/lb	10,606	10,406	10,250	10,077
Ultimate Analysis					
Carbon	%	59.40	57.76	56.96	55.75
Hydrogen	%	3.90	3.99	4.01	3.88
Oxygen	%	8.00	7.51	7.24	7.34
Nitrogen	%	1.10	1.16	1.06	1.09
Sulfur	%	3.60	3.00	3.00	3.03
Theoretical Emissions					
SO2	lb/MBtu	6.79	5.77	5.85	6.01
CO2	lb/MBtu	205	204	204	203

relatively low ash fusion temperatures, suitable for firing in cyclone furnaces.
The makeup of Linwood Hydrated Lime sorbent, i.e. $Ca(OH)_2$ and free H_2O content, was determined by the supplier. Table 5-14 lists these constituents. The average $Ca(OH)_2$ content was 93.0%, with a high of 94.7% and a low of 91.0%, while the average free moisture content was 0.8%, with a high of 1.3% and a low of 0.3%.

5.2.2 Gas Reburning Results

The performance of the GR system in controlling NO_x and its impacts on other gaseous emissions including CO, CO_2, and SO_2 are presented in this section. The program goal for Lakeside Unit 7 was to reduce NO_x by 60% at full load. GR operation was expected to modestly reduce CO_2 and SO_2, with no change in CO achieved, through judicious design of the OFA system. CO_2 is a major product of fossil fuel combustion and has been associated with the greenhouse global warming effect; SO_2 is precursor for acidic compounds associated with acid rain and CO is used as an indicator of combustion completion. To evaluate the GR system, parametric tests typically lasting one to two hours were conducted, with as many as seven completed in a day. Each process parameter was varied individually in order to evaluate its impact independent of the others.

5.2.2.1 NO_x Control

The process parameters relevant to NO_x control by GR include the stoichiometric ratio of each zone (coal, reburning, and exit), the gas heat input, reburning fuel injection details, and the FGR flow. These are discussed in the following paragraphs.

5.2.2.1.1 Gas Heat Input

Gas heat inputs in the range 10 to 26% were evaluated. Figure 5-45 shows NO_x emissions at full load as a function of gas heat input. The measurements indicate that

TABLE 5-14. ANALYSES OF LINWOOD HYDRATED LIME

Shipment Date	Trialer #	Ca(OH)2 (%, weight)	Free H2O (%, weight)
4/18/93	220	91.0	1.2
4/18/93	211	92.3	1.1
4/18/93	234	90.5	1.3
4/18/93	234	91.7	1.1
4/18/93	221	91.3	1.1
5/14/93	219	94.2	0.6
5/14/93	275	93.6	0.6
5/26/93		93.1	0.7
9/14/93	274	94.4	0.8
9/14/93	221	94.1	0.8
9/24/93	256	92.4	1.0
9/24/93	253	92.9	0.5
9/24/93	274	92.8	0.6
9/24/93	221	92.4	0.9
10/8/93	274	94.6	0.3
10/8/94	253	94.7	0.3
10/8/93	211	93.9	0.4
10/8/93	222	94.0	0.6
Average		**93.0**	**0.8**

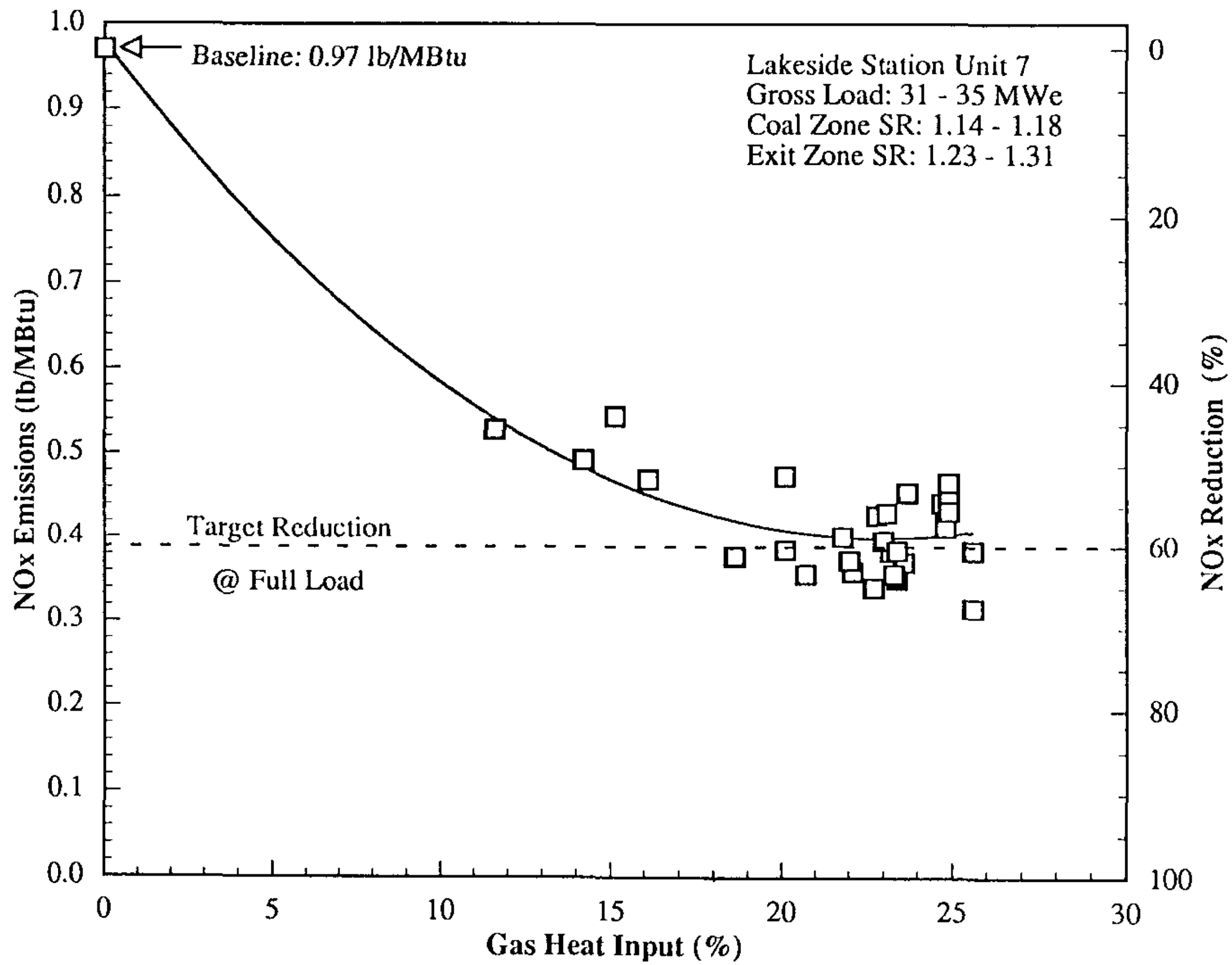


Figure 5-45. NO_x emissions as a function of gas heat input at full load

60% reduction, 0.39 lb/10^6Btu (167 mg/MJ) at full load, was met under some conditions at gas inputs of 20 to 26%. The variations in NO_x are due to ranges in coal (cyclone), reburning and exit zone stoichiometric ratios and other parameters tested. Figure 5-46 shows NO_x data at mid/low load as a function of gas heat input. In these cases, 60% reductions to 0.34 lb/10^6Btu (146 mg/MJ) at mid load and 0.32 lb/10^6Btu (138 mg/MJ) low load, were achieved at gas inputs of 20 to 25%. Improved NO_x reductions were measured at low load (19 to 20 MW_e), relative to that at other loads. This is likely due to enhanced mixing of reburning fuel with the primary combustion gas under this condition to form a more uniform reducing zone. At full load the maximum NO_x reduction was 69%, at a gas heat input of 25%, while at mid and low loads NO_x reduction as high as 71% was measured at gas heat inputs of 23 to 26%. In some of these cases, CO emissions were higher than generally acceptable, i.e. above 200 ppm, as will be discussed below. The maximum NO_x reductions achieved with adequate fuel burnout were 65% at full load and 71% at mid load.

5.2.2.1.2 Furnace Zone Stoichiometric Ratios

The stoichiometric ratios of the three zones significantly impact the NO_x control process. Limiting the coal zone stoichiometric ratio limits the formation of NO_x in this high temperature zone. Low coal zone stoichiometric ratio also result in a reduction in the O_2 level in the reburning zone, and therefore lower reburning zone stoichiometric ratios. The impacts of coal and reburning zone stoichiometric ratios at full load are shown in Figure 5-47. The data show that operation at coal stoichiometric ratio of 1.08 and reburning zone stoichiometric ratio of 0.83 resulted in the highest NO_x reduction at full load (67% for the conditions indicated), while operation at a coal zone *stoichiometric ratio of* 1.15 *and reburning zone stoichiometric ratio of* 0.9 *achieved* the target NO_x reduction of 60%.

The impacts of exit zone stoichiometric ratio on NO_x and CO emissions at full and reduced loads are shown in Figures 5-48 and 5-49, respectively. Burnout air is used

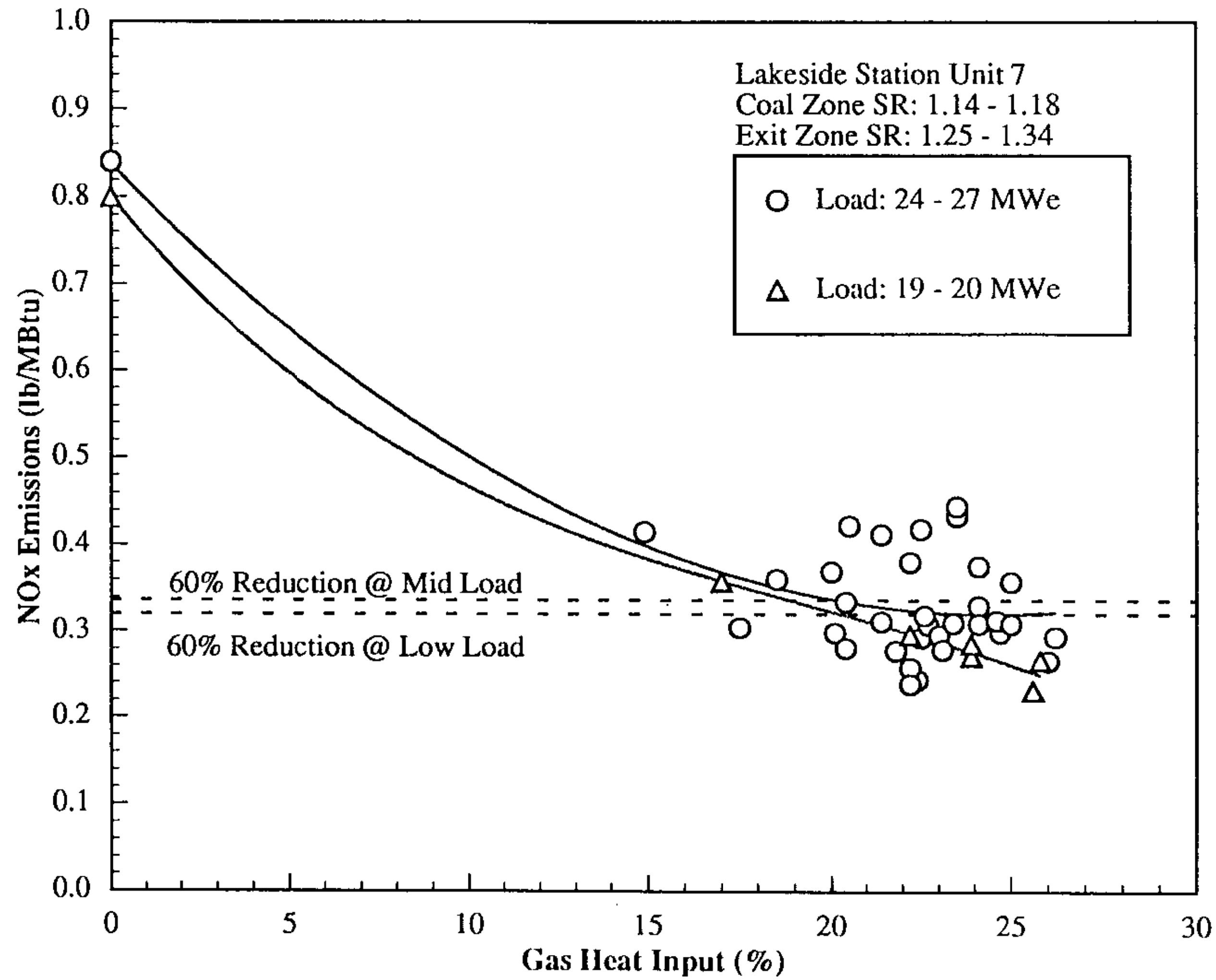


Figure 5-46. NO_x emissions as a function of gas heat input for mid and low load operation

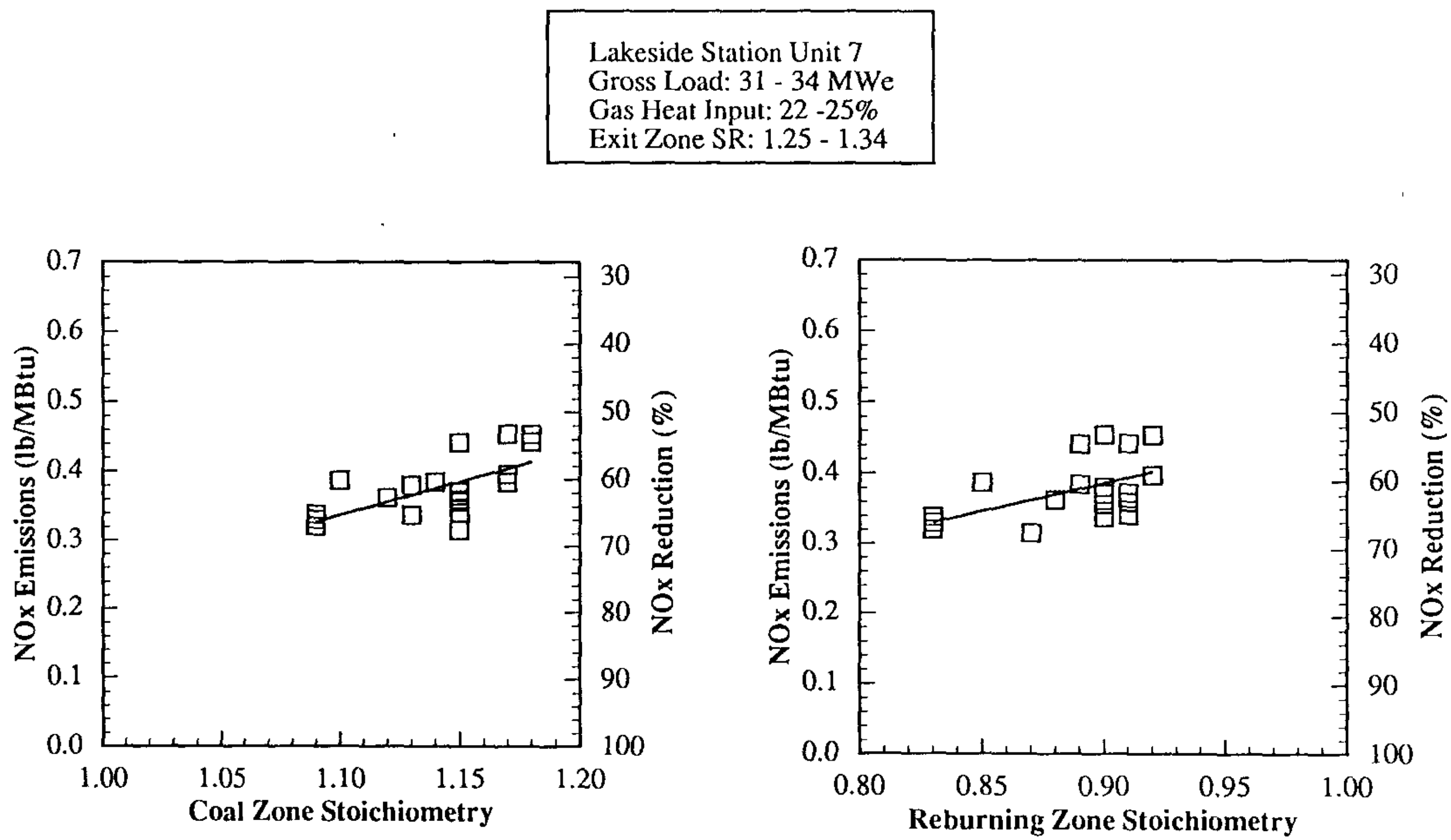


Figure 5-47. NO_x emissions as a function of coal and reburning zone stoichiometries at full load

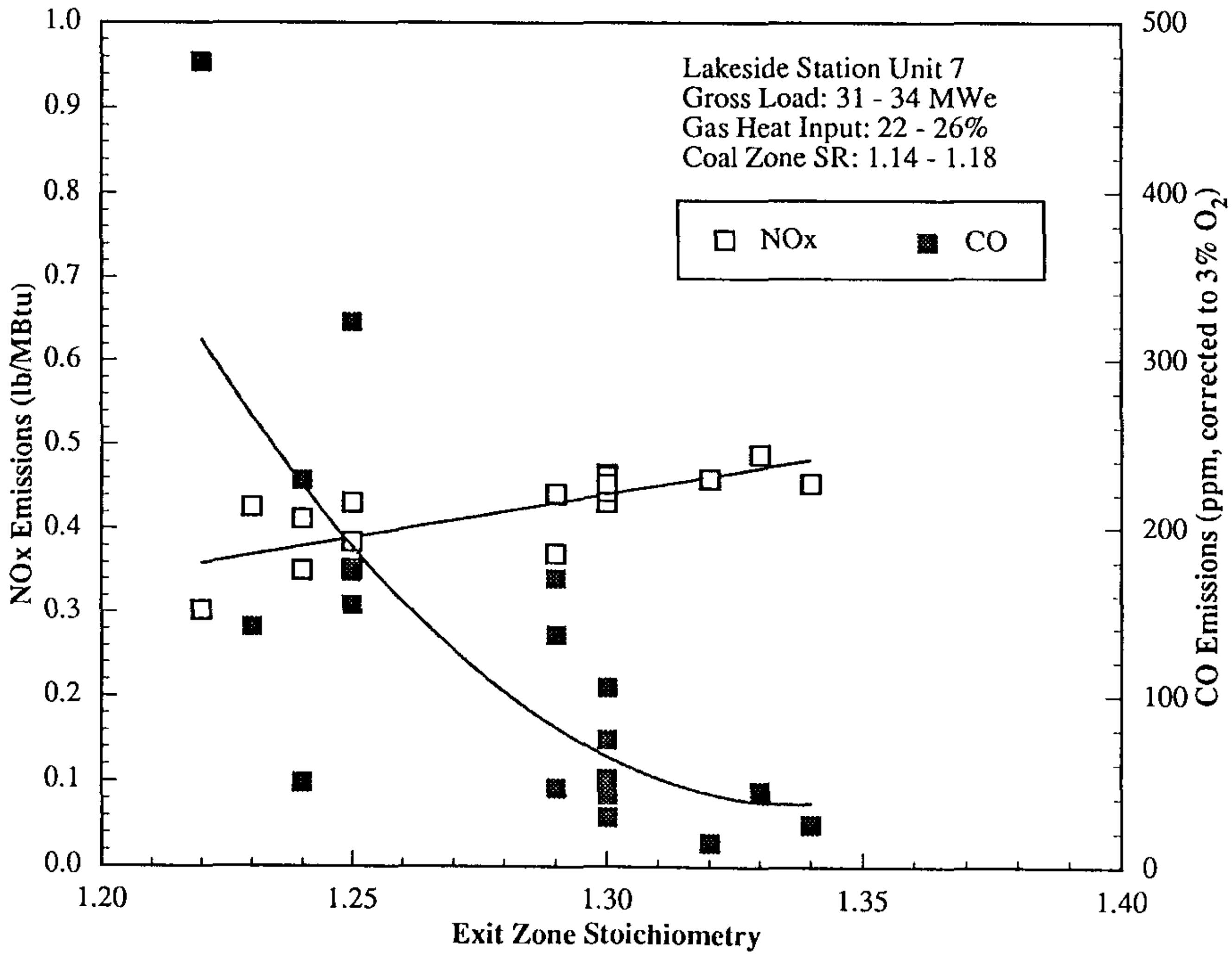


Figure 5-48. NO_x and CO emissions as a function of exit zone stoichiometry at full load

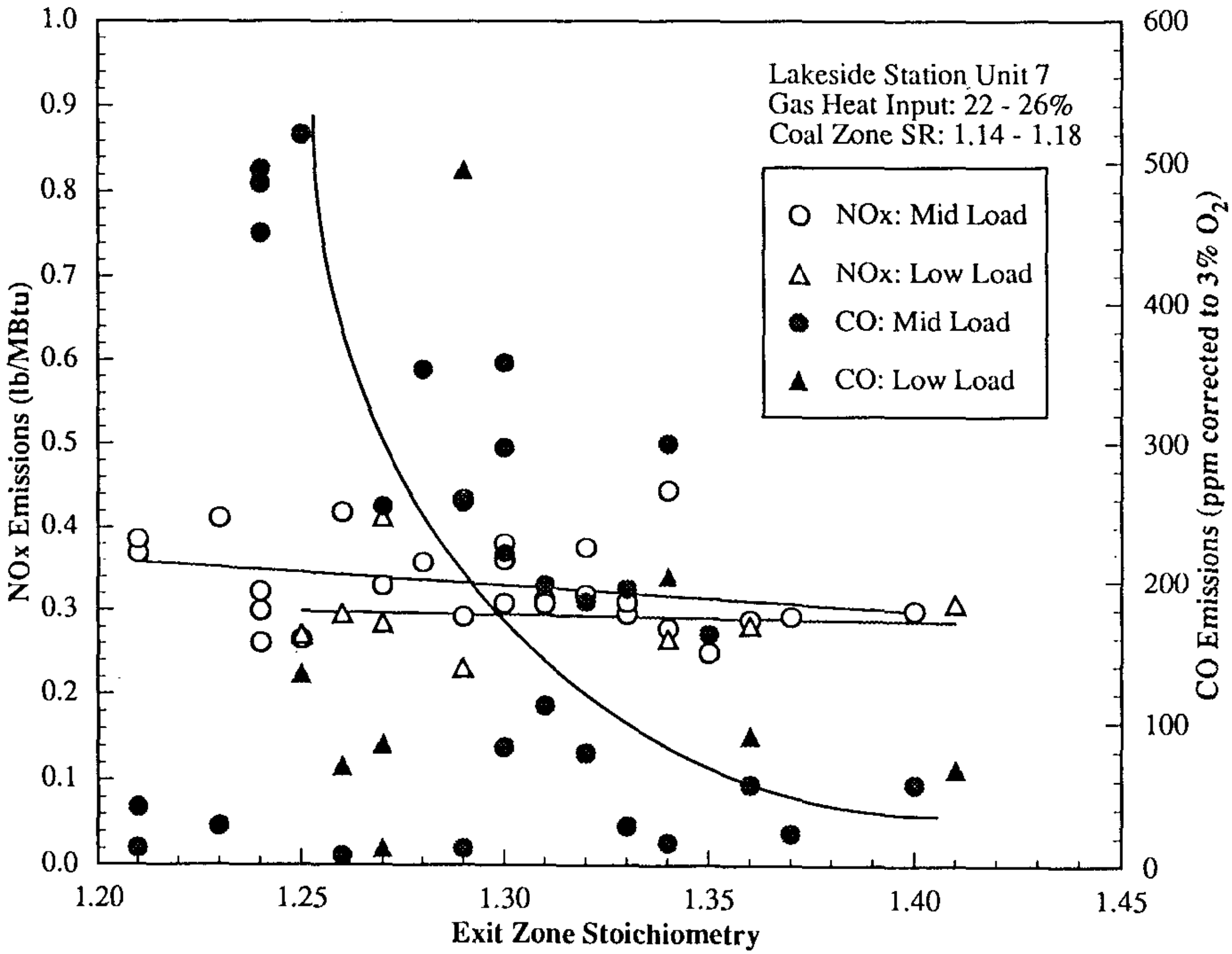


Figure 5-49. NO_x and CO emissions as a function of exit zone stoichiometry for mid and low load operation

to complete combustion; therefore, lower CO levels are expected at higher exit zone stoichiometric ratios. At full load, an exit zone stoichiometric ratio of 1.20 was expected to achieve fuel burnout. However, in practice an exit zone stoichiometric ratio of 1.30 was needed to maintain CO emissions below 200 ppm. At mid and low loads, an exit zone stoichiometric ratio of 1.35 was needed. The exit zone stoichiometric ratio has a relatively minor impact on the final NO_x level since the gas temperature at the point of OFA addition is relatively low. At mid and low load, there was essentially no change in NO_x with excess air.

5.2.2.1.3 Reburning Fuel Injector Size

In the Lakeside GR-SI demonstration, two sizes of reburning fuel injectors were tested. The early tests were conducted with relatively large injectors, which had relatively low injection velocity. These were larger than originally specified by the process design studies. At the completion of several parametric tests, an evaluation of test data was undertaken which included furnace flow modeling. This evaluation showed that improved NO_x reductions may be attained with smaller diameter injectors. The smaller injectors were installed and used throughout the long-term GR-SI demonstration.

The impacts of injector optimization on NO_x emissions at full and mid load are shown in Figure 5-50. In both cases, the smaller injectors improved NO_x reduction. This is due to improved reburning fuel jet mixing with primary (cyclone) combustion products. The final (optimized) injectors had a velocity near to that originally specified by the process design studies. On average, NO_x reductions improved by 3 to 5% with the smaller reburning fuel injectors.

5.2.2.1.4 Recirculated Flue Gas

The FGR flow was varied widely, from 3000 to 6000 scfm (1.42 to 2.83 Nm^3/s). FGR was used as a carrier gas to improve the mass flux of the reburning fuel jets and

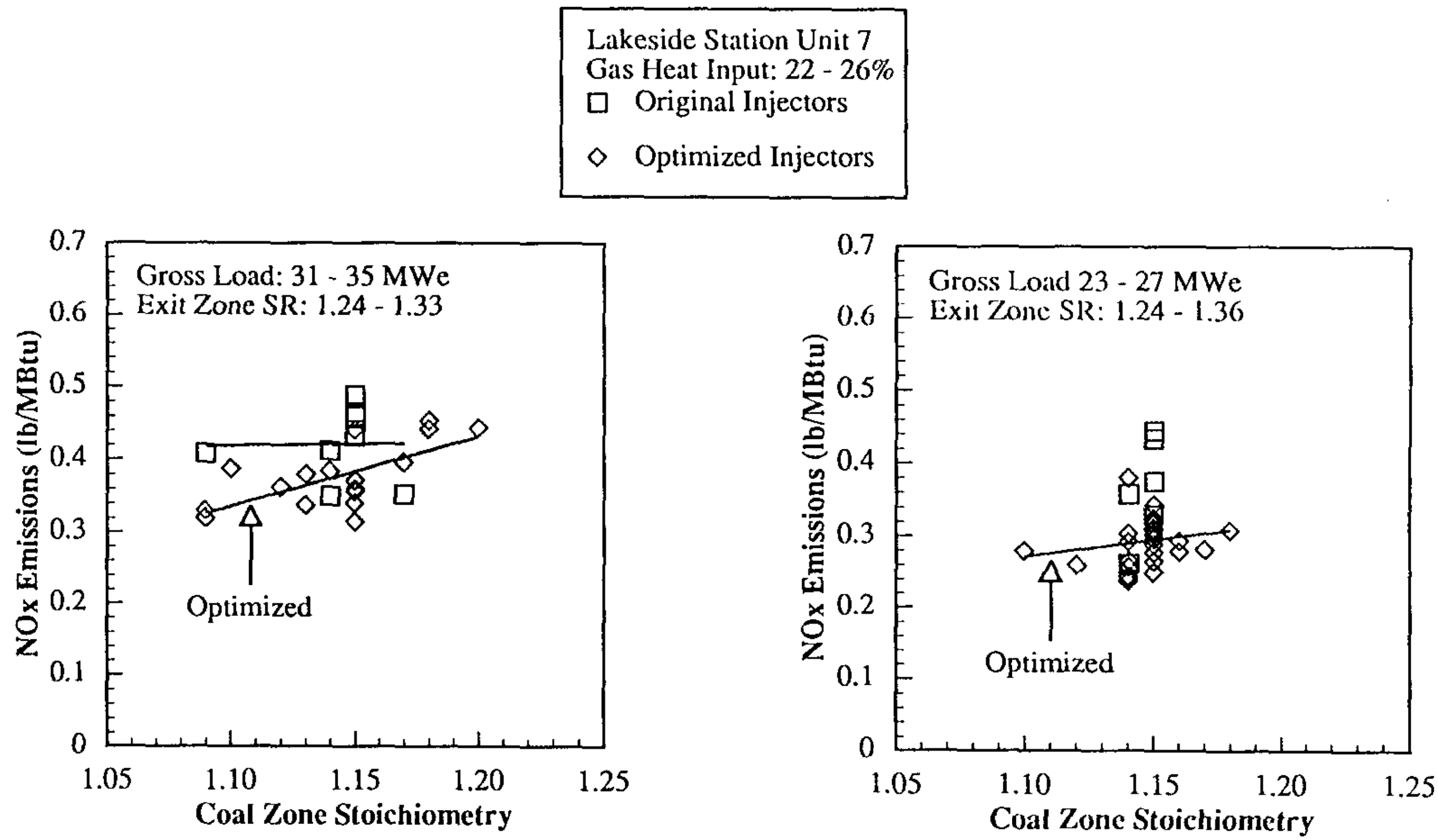


Figure 5-50. Impacts of reburning fuel injector optimization on NO_x emissions at full and mid loads

thereby reduce the mixing time. As expected, higher flows of FGR helped achieve the lowest NO_x level. This was most clearly the case at low load (19 to 20 MW_e). The impacts of FGR, expressed as a percentage of total flue gas, at full, mid, and low loads are shown in Figures 5-51 and 5-52. At full load, FGR of 6 to 7% achieved optimum results, while at mid load 8 to 9% achieved highest NO_x reduction, and at minimum load 9 to 10% was optimum.

5.2.2.1.5 SO_2 and CO_2 Emissions

Emissions of SO_2 and CO_2 were modestly reduced in GR-only operation. This resulted from the differences in composition of coal and natural gas, since natural gas is essentially sulfur free and has a higher hydrogen/carbon ratio than coal. Emissions of SO_2 as a function of gas heat input are shown in Figure 5-53. A reduction in SO_2 equivalent to the gas heat input was observed. Therefore, SO_2 reductions were generally 20 to 25%, which is the range of gas heat input most commonly evaluated.

Emissions of CO_2 were also moderately reduced by GR. The CO_2 concentration was reduced from 15.4% to 14.2% at a gas heat input of 25%. Under baseline coal-only operation, the theoretical CO_2 level was 203 lb/10^6Btu (85.3 g/MJ). The natural gas composition indicated a CO_2 level of 120 lb/10^6Btu (51.5 g/MJ). Therefore, replacement of 25% of the coal heat input with natural gas theoretically resulted in CO_2 reduction of 10%. The reduction based on the measured volume percentage stated above was 8%. This modest reduction in CO_2 was evident in Figure 5-54, which shows the CO_2 concentration as a function of gas input.

5.2.3 Sorbent Injection Results

The performance of the SI system was initially evaluated with parametric SI-only tests. This was followed by a co-application of both GR and SI technologies over the long-term testing period. The parameters which impact SO_2 capture in SI are the Ca/S

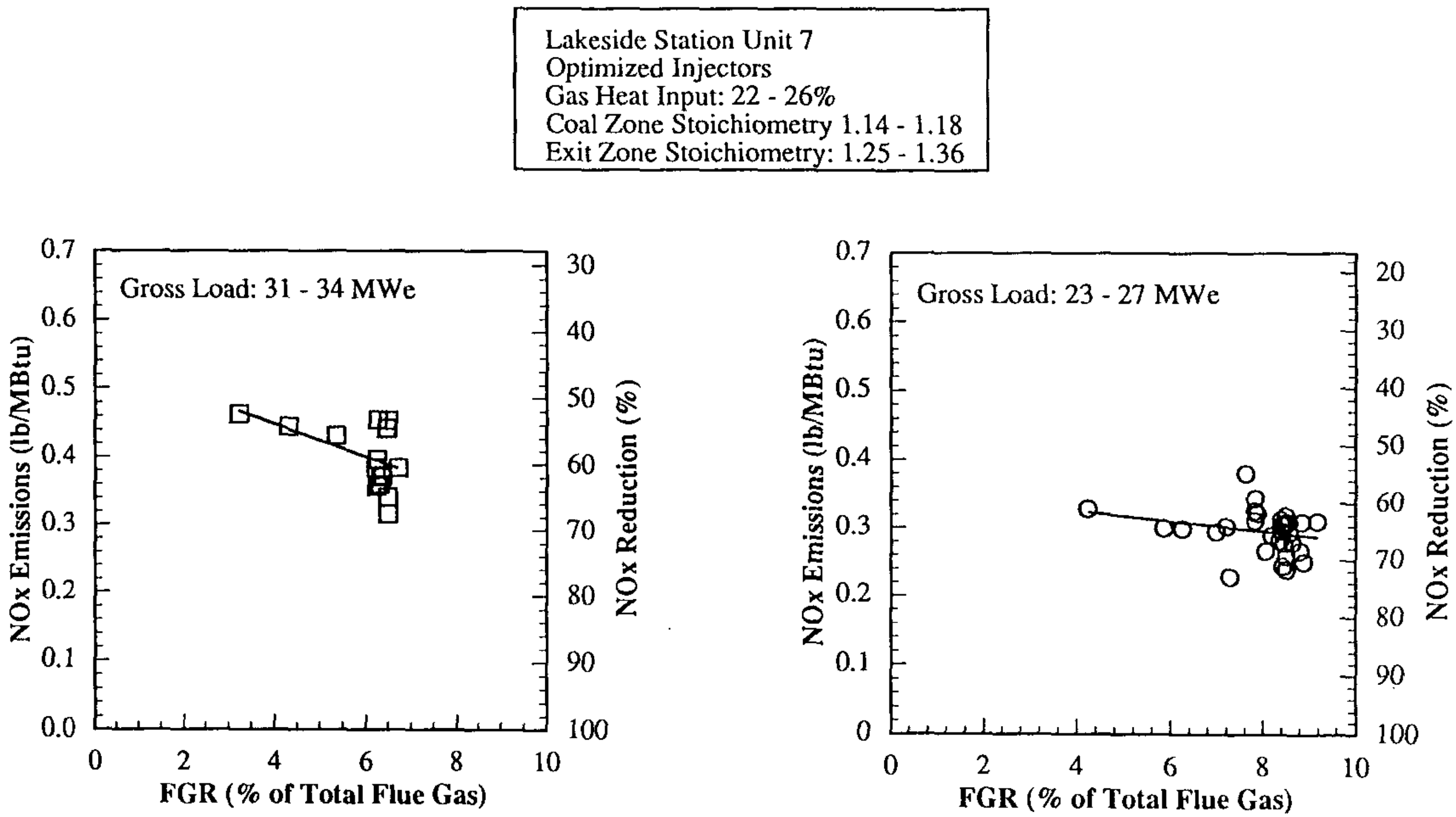


Figure 5-51. Impacts of recirculated flue gas at full and mid loads

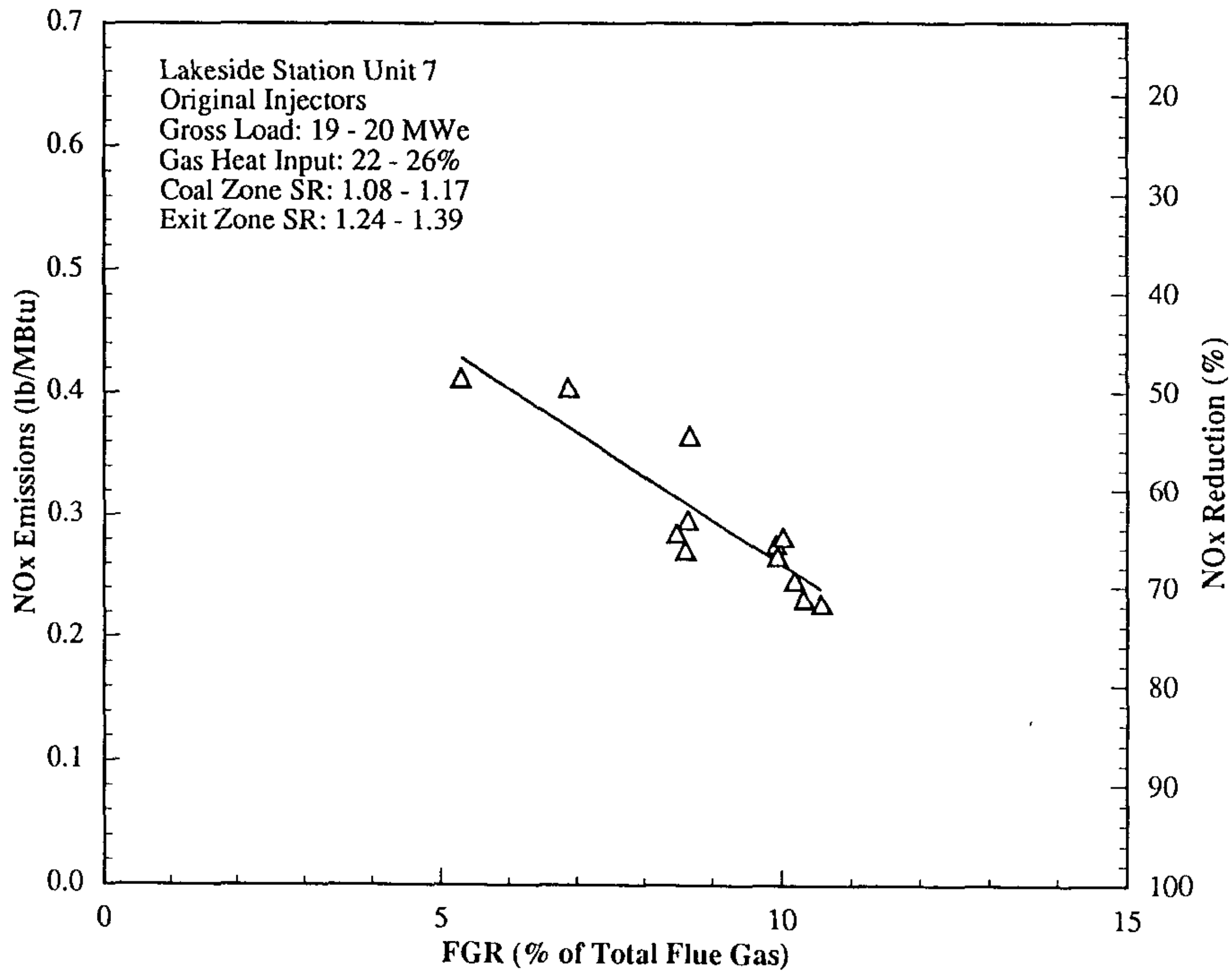


Figure 5-52. Impact on recirulcated flue gas on NO_x emissions

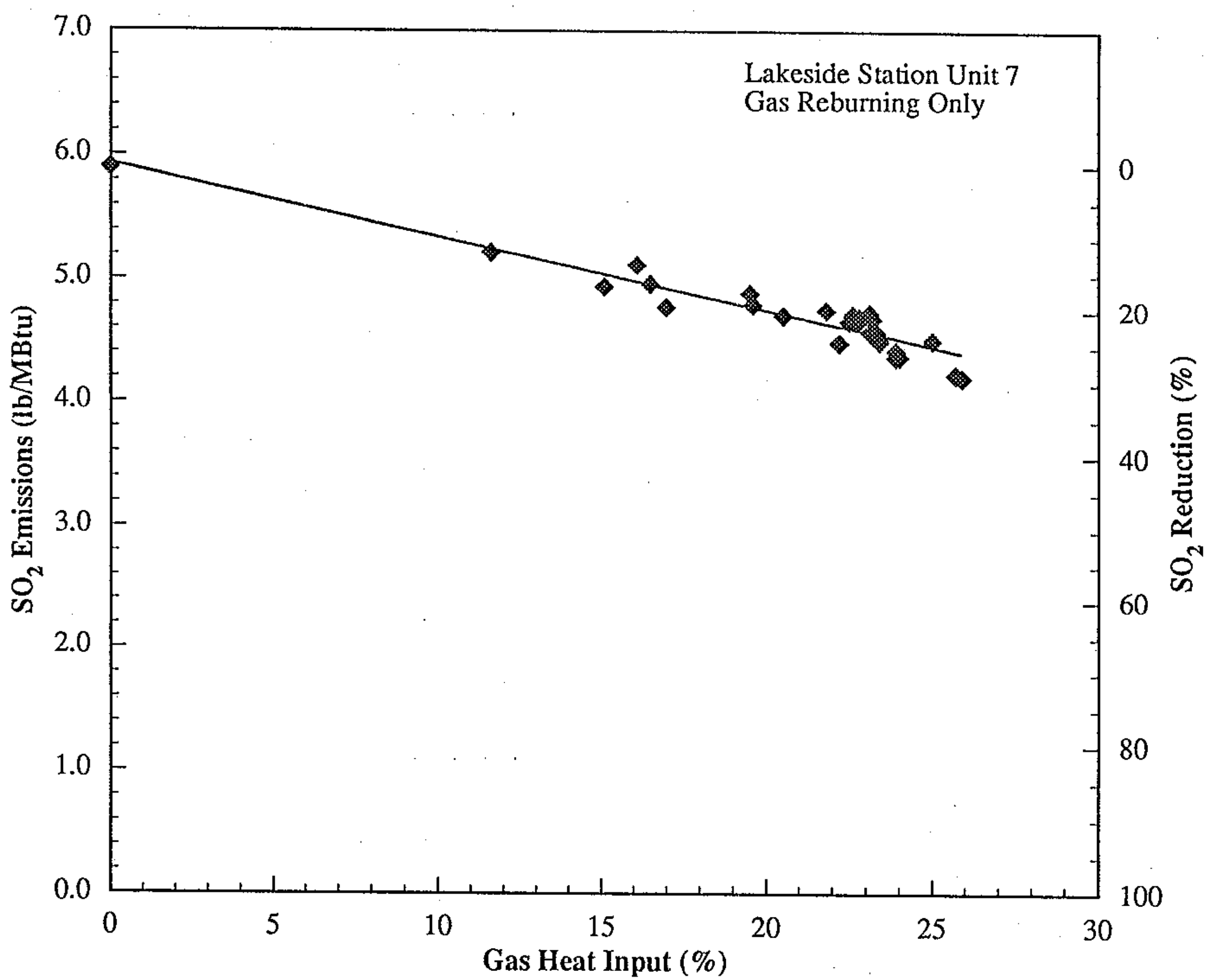


Figure 5-53. SO_2 emissions as a function of gas heat input (sorbent injection: off)

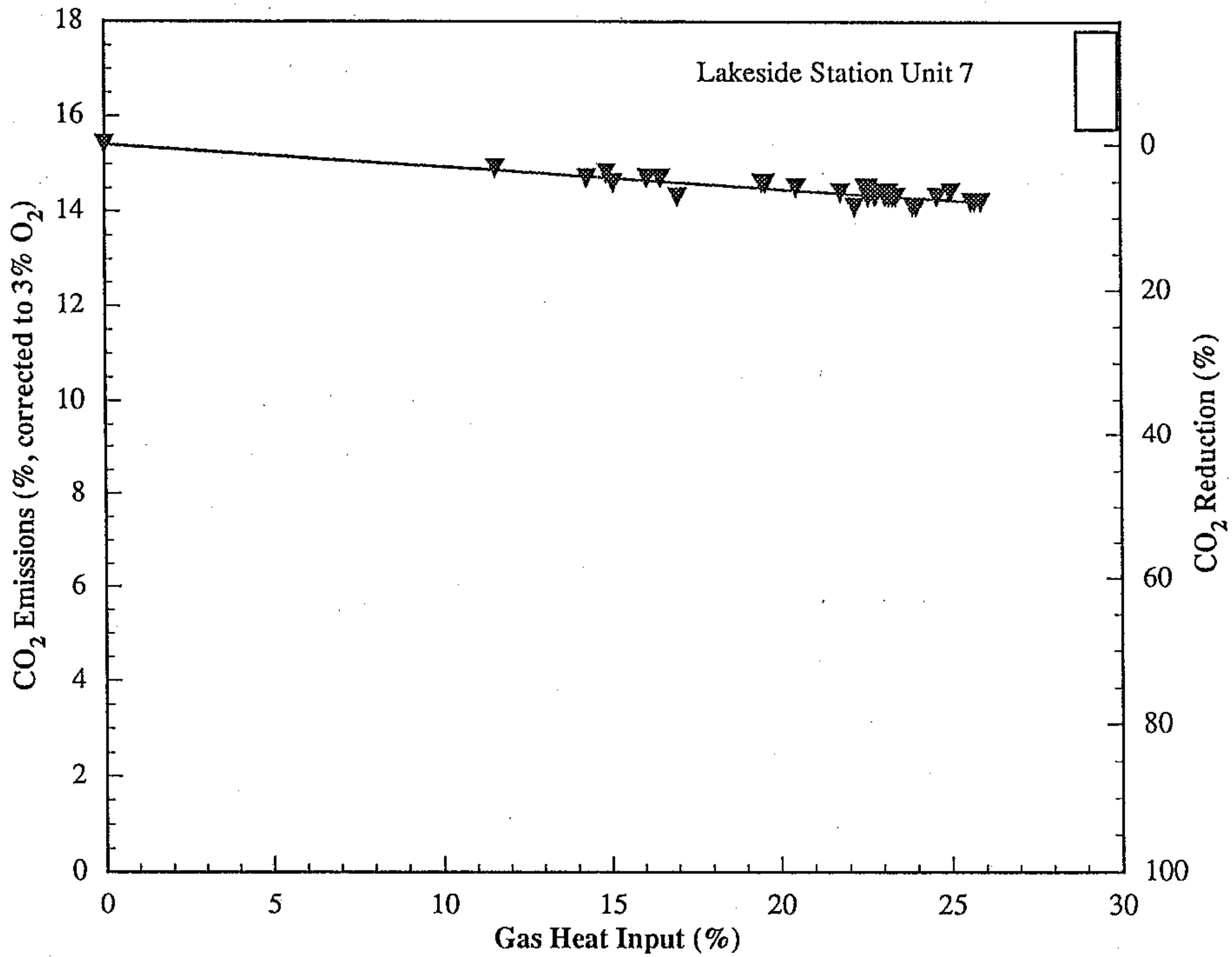


Figure 5-54. CO_2 emissions as a function of gas heat input

molar ratio, the SI air flow, and the injection temperature (and indirectly the load). Sorbent characteristics, such as type (hydrate or carbonate) and fineness also impact SO_2 capture. Linwood hydrated lime was the baseline sorbent during the long-term GR-SI evaluation. In addition, two sorbents supplied by NovaCon Energy Systems of Bedford, N.Y. were tested at the conclusion of the field test. Appendix 4, Volume 4 - GR-SI at Lakeside Unit 7, presents results of the alternate sorbents test.

5.2.3.1 SO_2 Control

Furnace SI has been developed for SO_2 reductions in the 25 to 50% range. When combined with GR, higher SO_2 reductions can occur due to coal replacement. Limited SI-only testing was characterized to optimize the process. The process was evaluated over the full load range with Ca/S molar ratios from 1.0 to 3.0. SI air flows were evaluated in the range 1800 to 4600 scfm (0.85 to 2.17 Nm^3/s). Reductions in SO_2 were calculated from the 5.9 $lb/10^6Btu$ (2540 mg/MJ) baseline.

5.2.3.1.1 Ca/S Molar Ratio

The SO_2 emissions/reductions under SI operation, for the range of load 19 to 34 MW_e, are shown in Figure 5-55. While succeeding figures differentiate data at different loads, on average the SO_2 reductions were 25% at a Ca/S of 1.1 and 42% at a Ca/S of 2.1. Figure 5-56 shows the SO_2 levels under GR-SI operation with gas heat inputs of 22 to 25%. On average, the SO_2 reductions were 51% at a Ca/S of 1.1 and 61% at a Ca/S of 2.1. In the majority of GR-SI cases with 22 to 25% gas heat input the design level of 50% SO_2 reduction, corresponding to 2.95 $lb/10^6Btu$ (1270 mg/MJ), was achieved. The maximum SO_2 reduction measured under GR-SI was 68% at a Ca/S of 2.09 and gas heat input of 23%.

The injection temperature and indirectly the operating load had strong impacts on SO_2 reduction and calcium utilization. Figure 5-57 shows full load data for two operating

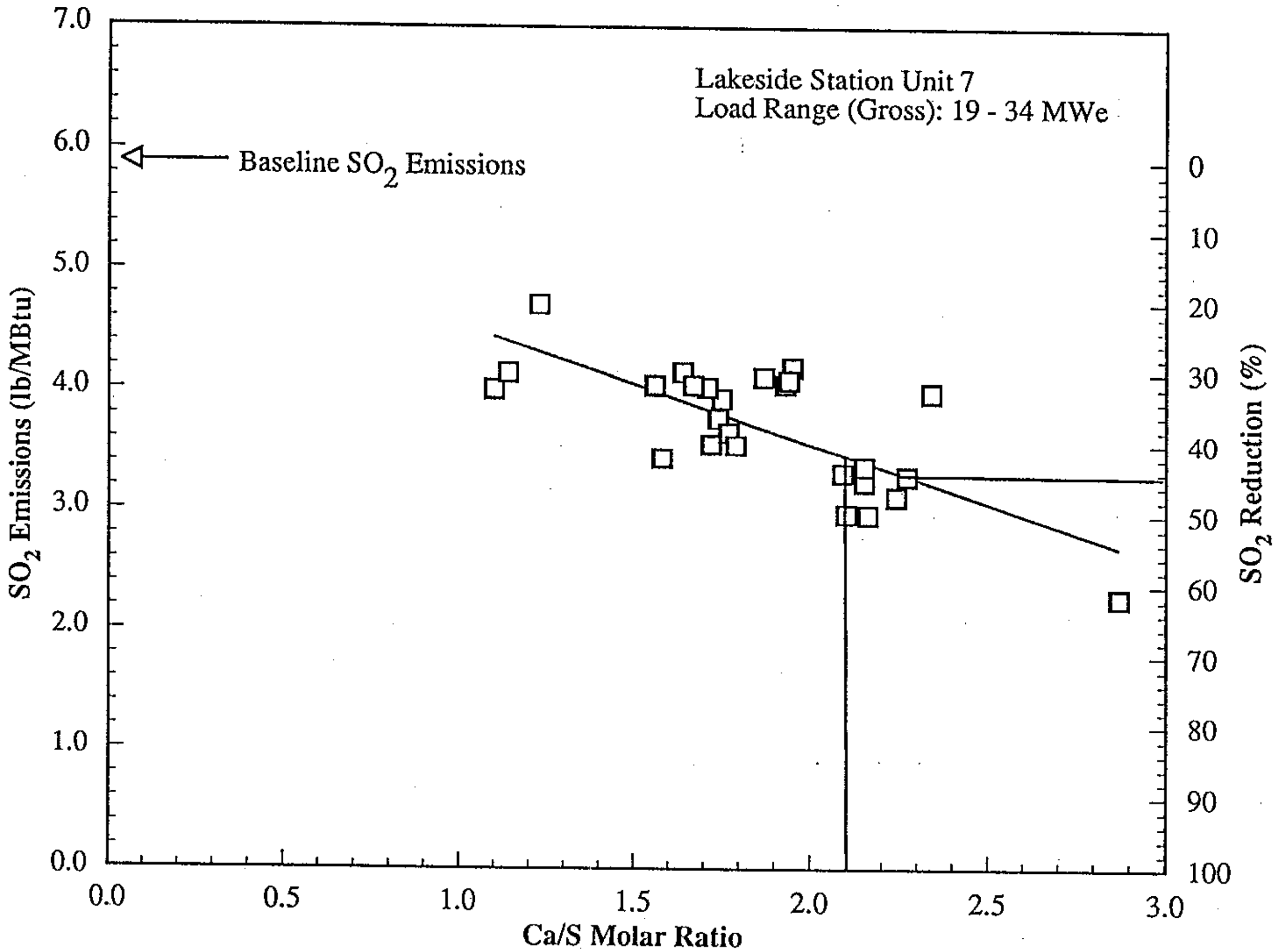


Figure 5-55. SO_2 emissions under SI-only operation

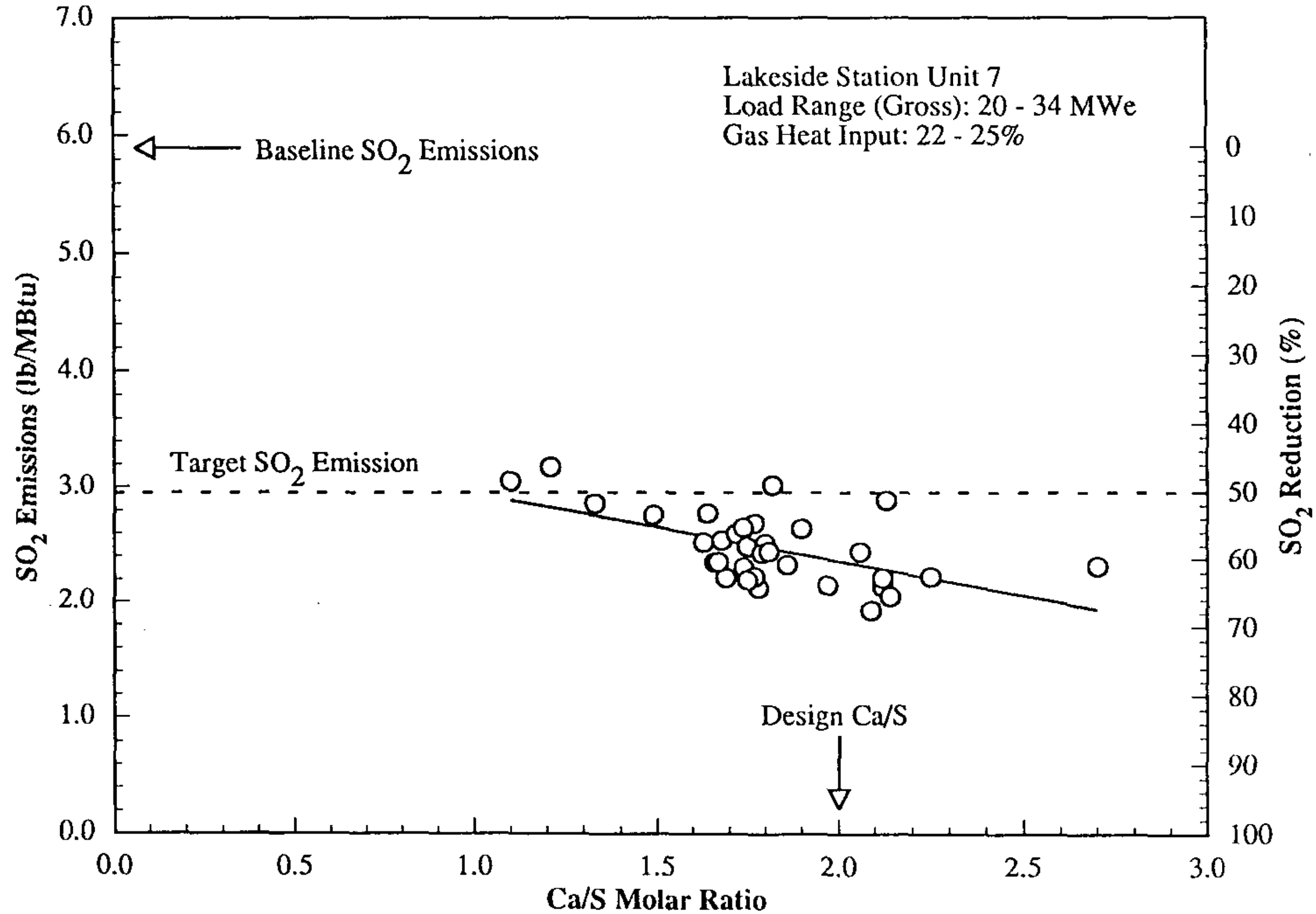


Figure 5-56. SO_2 emissions under GR-SI operation.

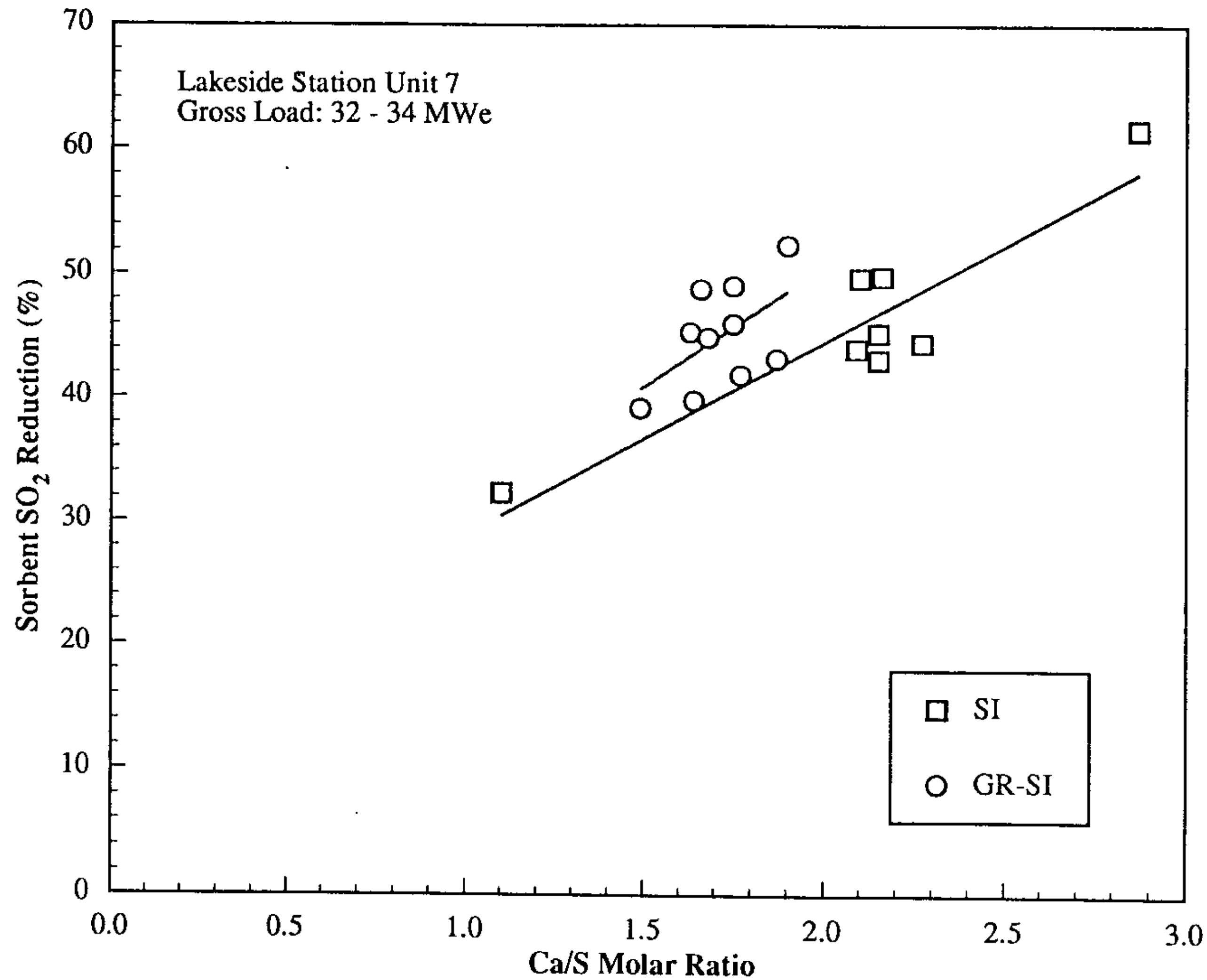


Figure 5-57. Reductions in SO_2 emissions due to sorbent capture.

conditions, SI-only and GR-SI, over a range of Ca/S molar ratio. While SI was evaluated with parametric tests over a wide range of Ca/S molar ratio, full load GR-SI operation was generally conducted with Ca/S in the 1.5 to 2.0 range. The data show that sorbent SO_2 capture was 4 to 6% higher when GR was applied with SI. GR resulted in an upward shift in the gas temperature at the SI planes, to a more suitable temperature for SO_2 capture. The corresponding Ca utilizations are shown in Figure 5-58. SI, with hydrated lime, generally results in a Ca utilization in the 20 to 30% range. That was the case in this application. On average, a 1.5 to 2.5% increase in Ca utilization resulted from GR-SI operation over levels for SI-only operation under full load. However, at reduced loads the impact of GR on the SO_2 capture process was more significant. Figure 5-59 shows calcium utilizations for Ca/S molar ratios of 1.9 to 2.2 over the load range. With GR-SI, calcium utilization increased by as much as 7% at 20 MW_e to 3% at 33 MW_e.

5.2.3.1.2 Sorbent Injection Air Flow

SI air was used to increase the mass flux of sorbent jets and thereby enhance mixing. Since the process is temperature dependent, rapid mixing with the flue gases at the exit of the furnace must take place, otherwise a loss in process efficiency results. Figure 5-60 shows SO_2 emissions under GR-SI and SI-only operation at full load, for a range of SI air flows. Modest reductions in SO_2 emissions were measured at high SI air flows. Under GR-SI, the SI air flow of 3700 scfm (1.75 Nm^3/s) was commonly used and optimum results were achieved with 4600 scfm (2.17 Nm^3/s).

5.2.4 GR-SI Long-Term Results

Data for long-term GR-SI demonstration were recorded from October 4, 1993 to June 3, 1994. This period includes scheduled months of relatively heavy use of the unit. Generally, GR and SI systems were both in operation; however, at times only GR was in operation.

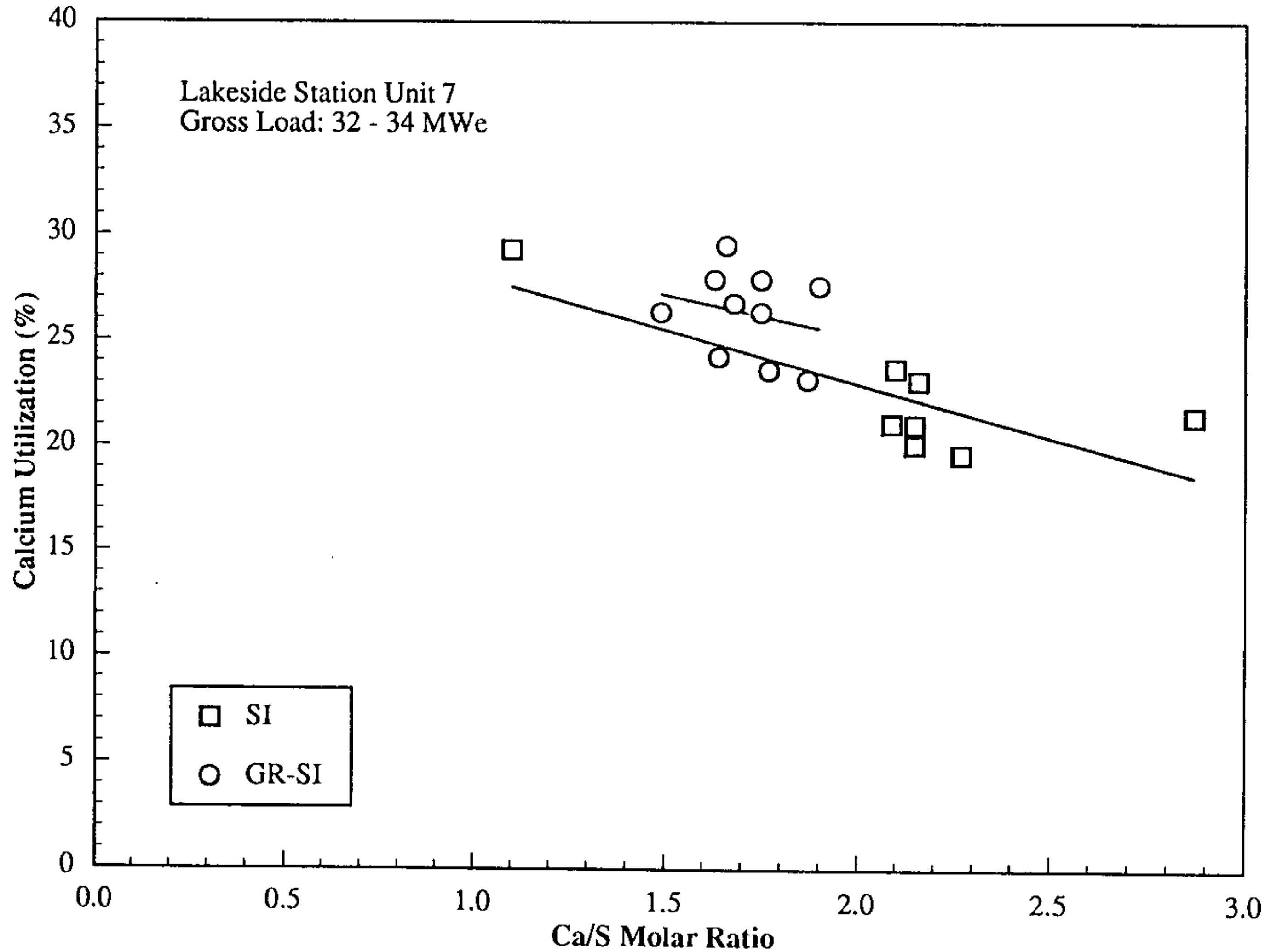


Figure 5-58. Calcium utilization as a function of Ca/S molar ratio.

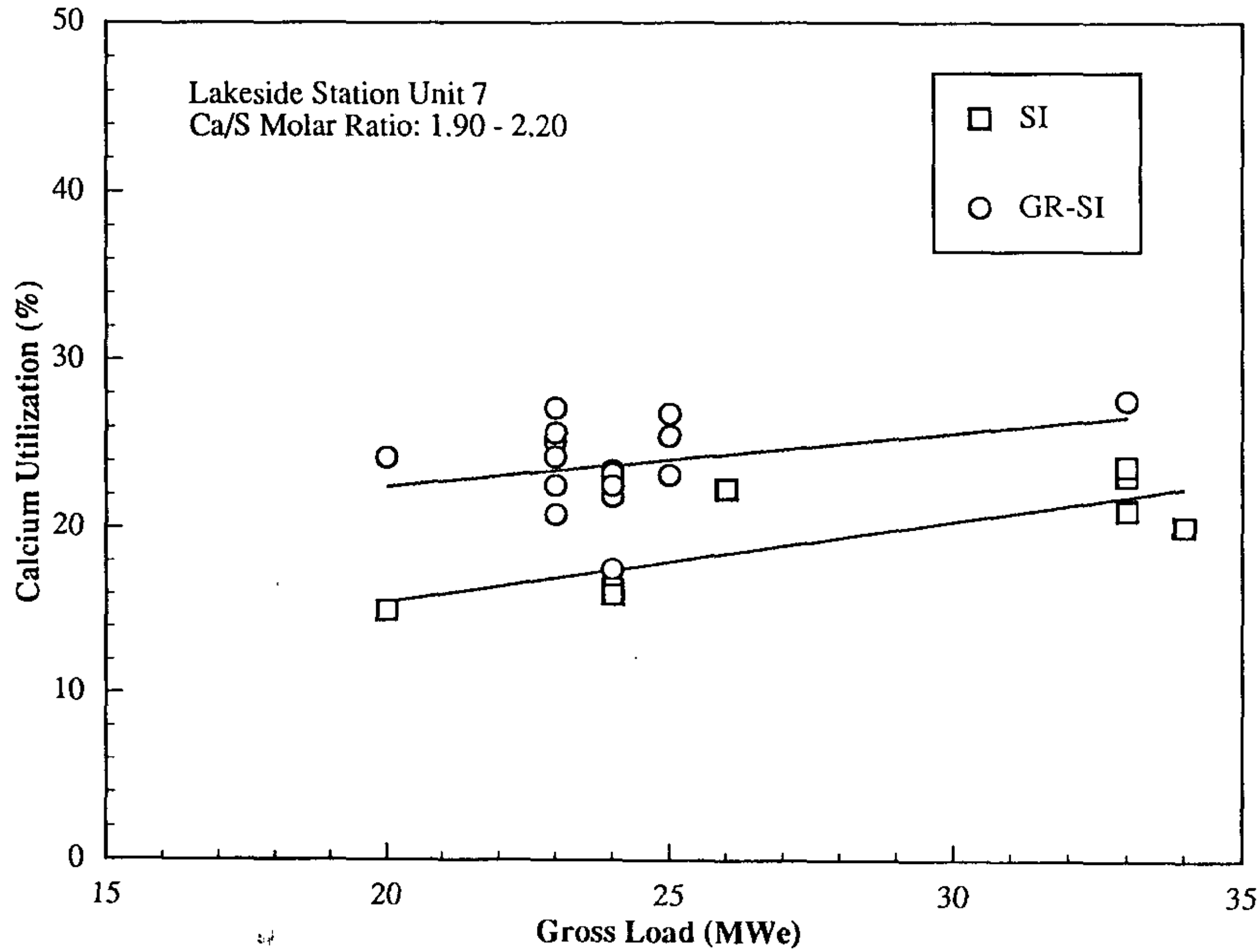


Figure 5-59. Calcium utilization as a function of electric load.

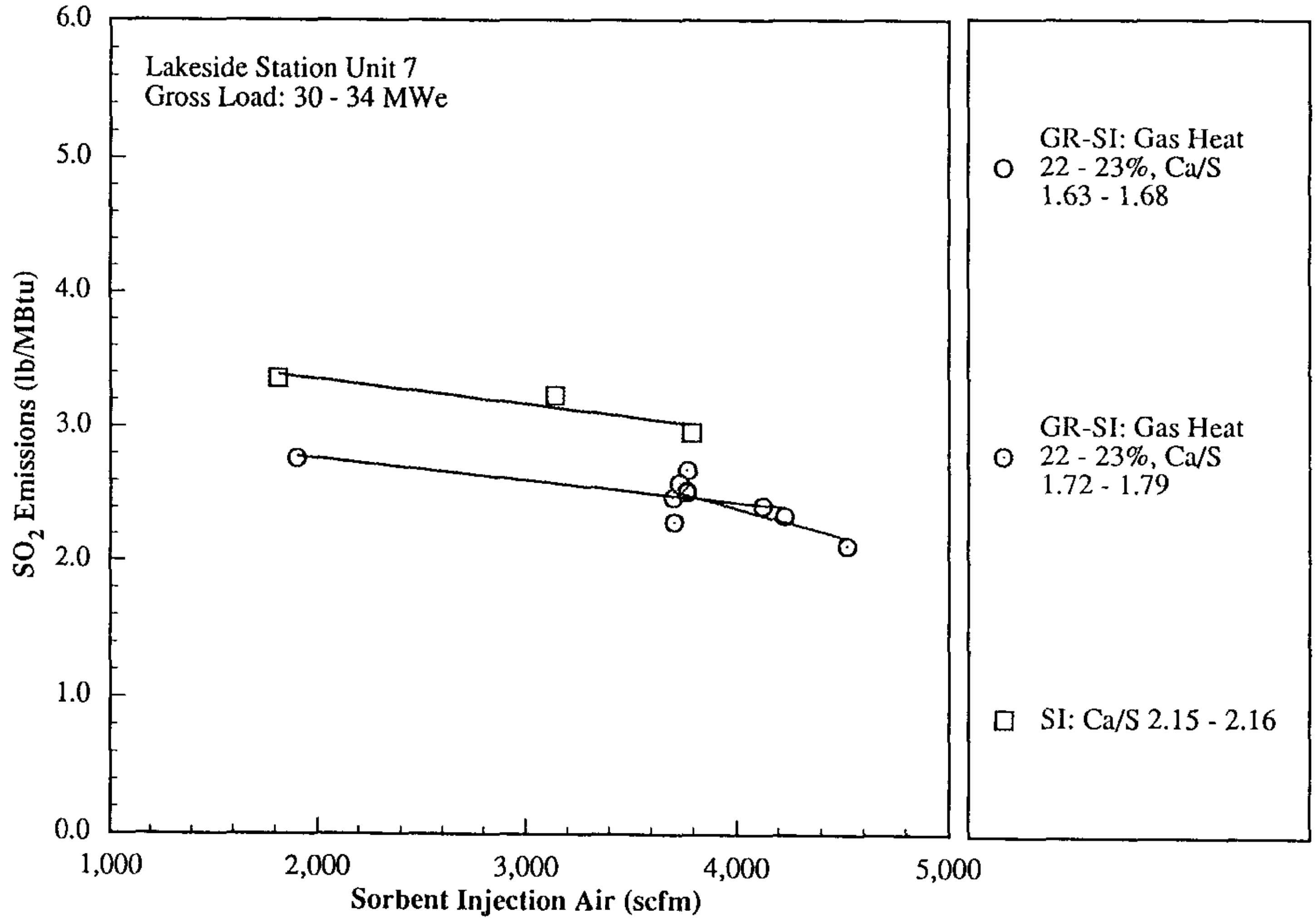


Figure 5-60. SO_2 emissions as a function of sorbent injection air flow

5.2.4.1 NO_x and SO_2 Control

The NO_x and SO_2 reductions measured over this period are shown in Figure 5-61a and 5-61b. The target reductions of 60% for NO_x and 50% for SO_2 are also shown. Generally, gas heat inputs of 22 to 24% were used, which approximate the design level of 24%, and Ca/S was in the range of 1.5 to 1.9 at full load and 1.9 to 2.1 at reduced load. On average, the Ca/S during the long-term testing period was below the design level of 2.0. Over the long-term testing period, NO_x reduction averaged 63% and SO_2 reduction averaged 58%.

5.2.5 Impacts of GR, SI, and GR-SI on Boiler Thermal Performance

In this section the impacts of GR, SI, and GR-SI operation on boiler thermal performance are discussed. In steam generating units, the heat released from combustion of fuels must be absorbed by heat exchangers with high efficiency. These include the furnace waterwall, the secondary superheater, primary superheater, generating bank, and air heater. Lakeside Unit 7 is not equipped with either a reheat cycle or an economizer. The unit must generate steam at conditions (temperature and pressure) near to the design point to drive the steam turbine and generator. The design final steam conditions are a temperature of 910°F (488°C) and pressure of 875 psig (6030 kPa). Elevated steam temperature and pressure are preferred since they result in the lowest heat rate. The unit must operate with minimum deposition of ash on the furnace waterwall and convective heat exchangers.

The thermal performance of Lakeside Unit 7 under baseline, GR, SI, and GR-SI operation are summarized in Table 5-15 through 5-18. Averages of steam temperatures, gas temperatures, heat absorptions by each heat exchanger, Heat Absorption Ratios (HAR), and heat losses are presented for full (33 MW_e), mid (25 MW_e), and low (20 MW_e) loads. The HAR relate the quantity of heat absorbed to that absorbed under a specific baseline case. Under full load baseline operation the boiler

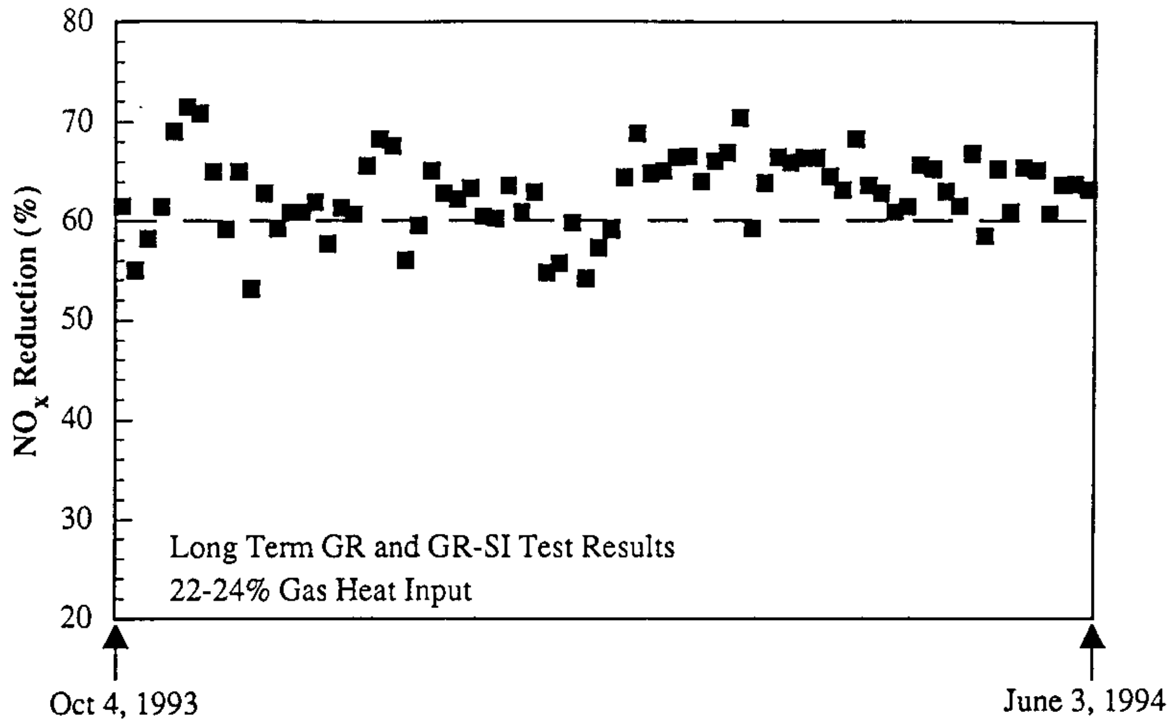


Figure 5-61a. Long-term operation results for NO_x reduction

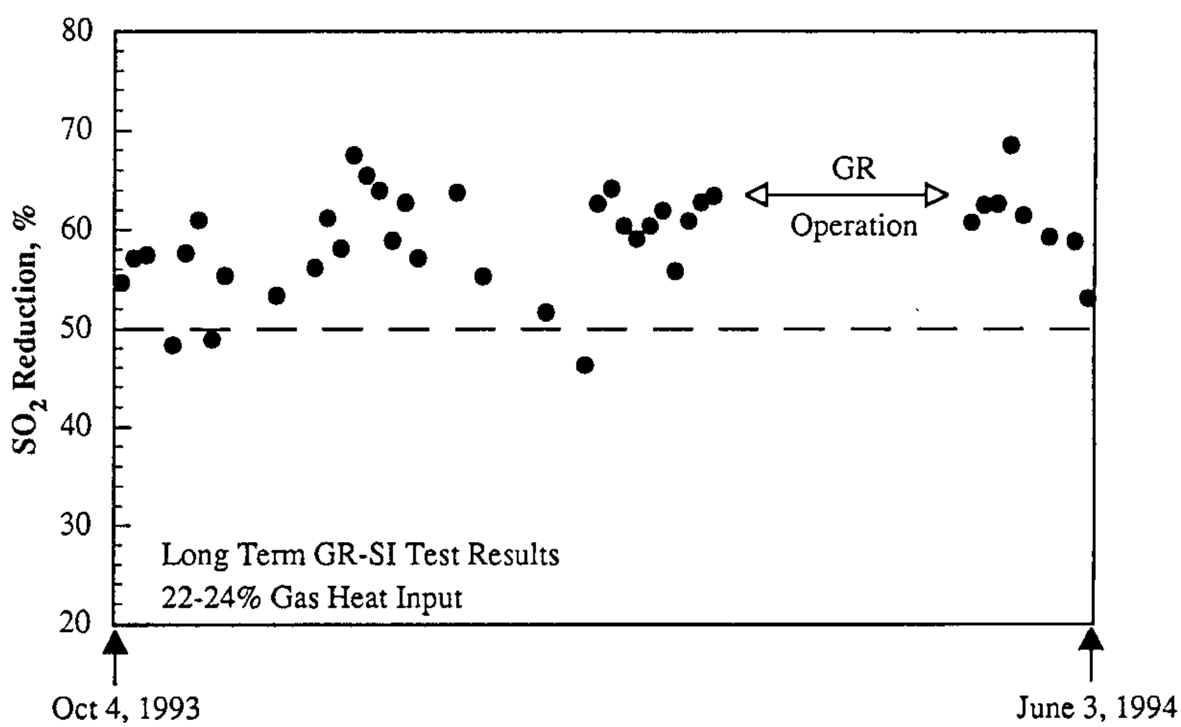


Figure 5-61b. Long-term operation results for SO_2 reduction.

TABLE 5-15. THERMAL PERFORMANCE UNDER BASELINE WITH OFA STAGING

Gross Load (MWe)	20	25	33
Coal (Cyclone) Zone SR	1.16	1.15	1.18
Exit Zone SR	1.30	1.27	1.28
OFA (% of Combustion Air)	9.12	9.03	9.32
Boiler O2 (%, dry)	4.31	3.59	3.54
Secondary Superheater Outlet Temperature (°F)	895	892	891
Secondary Superheater Outlet Pressure (psig)	884	880	881
Primary Superheater Outlet Temperature (°F)	771	782	811
Drum Attemperator Outlet Temperature (°F)	723	712	701
Boiler Drum Pressure (psig)	897	906	934
Boiler Bank Gas Outlet Temperature (°F)	609	641	674
Air Heater Gas Outlet Temperature (°F)	304	322	336
Heat Absorption (MBtu/hr)			
Furnace	152	175	215
Secondary Superheater	20	26	36
Primary Superheater	37	47	67
Generating Bank	13	18	26
Attemperation	6	10	21
Air Heater	25	30	40
Heat Absorption Ratio			
Furnace	1.02	1.02	1.01
Secondary Superheater	0.97	0.96	0.95
Primary Superheater	0.98	0.97	1.00
Generating Bank	0.91	0.94	0.93
Drum Attemperator	0.86	0.86	0.98
Air Heater	1.16	1.10	1.07
Heat Loss (%)			
Dry Gas	5.21	5.67	5.95
Moisture In Fuel	1.93	1.94	1.95
Moisture From Combustion	4.06	4.09	4.11
Combustible Matter in Refuse	0.81	0.81	0.81
Radiation	0.87	0.72	0.55
Unmeasured	1.50	1.50	1.50
Total Losses (%)	14.38	14.73	14.87
Boiler Efficiency (%)	85.62	85.27	85.13

TABLE 5-16. THERMAL PERFORMANCE UNDER GAS REBURNING

Gross Load (MWe)	20	25	33
Gas Heat Input (%)	23	23	24
Coal (Cyclone) Zone SR	1.17	1.15	1.18
Reburning Zone SR	0.93	0.91	0.91
Exit Zone SR	1.34	1.30	1.29
Boiler O2 (%, dry)	4.63	4.33	4.02
Secondary Superheater Outlet Temperature (°F)	896	892	890
Secondary Superheater Outlet Pressure (psig)	881	881	882
Primary Superheater Outlet Temperature (°F)	785	812	837
Drum Attemperator Outlet Temperature (°F)	725	699	682
Boiler Drum Pressure (psig)	893	906	941
Boiler Bank Gas Outlet Temperature (°F)	620	645	677
Air Heater Gas Outlet Temperature (°F)	308	326	337
Heat Absorption (MBtu/hr)			
Furnace	146	168	204
Secondary Superheater	19	27	40
Primary Superheater	38	50	72
Generating Bank	16	20	29
Attemperation	7	16	30
Air Heater	24	27	42
Heat Absorption Ratio			
Furnace	0.99	1.00	0.95
Secondary Superheater	0.97	1.03	1.05
Primary Superheater	1.03	1.06	1.06
Generating Bank	1.20	1.13	1.01
Drum Attemperator	1.14	1.40	1.36
Air Heater	1.17	1.07	1.11
Heat Loss (%)			
Dry Gas	5.48	5.76	5.91
Moisture In Fuel	1.48	1.49	1.48
Moisture From Combustion	5.62	5.68	5.76
Combustible Matter in Refuse	0.62	0.62	0.61
Radiation	0.91	0.75	0.54
Unmeasured	1.50	1.50	1.50
Total Losses (%)	15.61	15.80	15.80
Boiler Efficiency (%)	84.39	84.20	84.20

TABLE 5-17. THERMAL PERFORMANCE UNDER SORBENT INJECTION

Gross Load (MWe)	20	25	33
Ca/S Molar Ratio	2.2	1.8	2.1
Coal (Cyclone) Zone SR	1.15	1.15	1.15
Exit Zone SR	1.36	1.26	1.29
Boiler O2 (%, dry)	5.74	5.01	4.06
Secondary Superheater Outlet Temperature (°F)	881	889	897
Secondary Superheater Outlet Pressure (psig)	884	881	885
Primary Superheater Outlet Temperature (°F)	753	815	801
Drum Attemperator Outlet Temperature (°F)	724	687	706
Boiler Drum Pressure (psig)	895	903	936
Boiler Bank Gas Outlet Temperature (°F)	661	658	741
Air Heater Gas Outlet Temperature (°F)	347	363	396
Heat Absorption (MBtu/hr)			
Furnace	152	181	224
Secondary Superheater	18	28	36
Primary Superheater	34	50	66
Generating Bank	13	17	22
Attemperation	4	18	19
Air Heater	26	30	44
Heat Absorption Ratio			
Furnace	1.02	1.07	1.04
Secondary Superheater	0.90	1.09	0.95
Primary Superheater	0.93	1.07	0.97
Generating Bank	0.97	0.94	0.77
Drum Attemperator	0.54	1.55	0.84
Air Heater	1.25	1.19	1.17
Heat Loss (%)			
Dry Gas	6.71	6.66	7.52
Moisture In Fuel	1.96	1.97	1.99
Moisture From Combustion	4.13	4.16	4.21
Combustible Matter in Refuse	0.81	0.81	0.81
Radiation	0.90	0.77	0.54
Unmeasured	1.50	1.50	1.50
Total Losses (%)	16.01	15.87	16.57
Boiler Efficiency (%)	83.99	84.13	83.43

TABLE 5-18. THERMAL PERFORMANCE UNDER GAS REBURNING-SORBENT INJECTION

Gross Load (MWe)	20	25	33
Gas Heat Input (%)	23	22	21
Ca/S Molar Ratio	2.1	1.6	1.7
Coal (Cyclone) Zone SR	1.16	1.15	1.15
Reburning Zone SR	0.93	0.92	0.92
Exit Zone SR	1.42	1.33	1.31
Boiler O2 (%, dry)	5.67	4.63	3.79
Secondary Superheater Outlet Temperature (°F)	885	890	894
Secondary Superheater Outlet Pressure (psig)	881	881	881
Primary Superheater Outlet Temperature (°F)	799	815	833
Drum Attemperator Outlet Temperature (°F)	702	684	682
Boiler Drum Pressure (psig)	891	905	929
Boiler Bank Gas Outlet Temperature (°F)	655	673	686
Air Heater Gas Outlet Temperature (°F)	351	361	343
Heat Absorption (MBtu/hr)			
Furnace	154	172	212
Secondary Superheater	21	29	39
Primary Superheater	40	51	68
Generating Bank	14	18	26
Attemperation	12	19	28
Air Heater	25	29	38
Heat Absorption Ratio			
Furnace	1.03	1.00	1.04
Secondary Superheater	1.06	1.10	1.09
Primary Superheater	1.08	1.06	1.06
Generating Bank	1.05	0.95	1.04
Drum Attemperator	1.81	1.59	1.41
Air Heater	1.31	1.12	1.12
Heat Loss (%)			
Dry Gas	6.85	6.67	5.96
Moisture In Fuel	1.52	1.54	1.52
Moisture From Combustion	5.67	5.65	5.65
Combustible Matter in Refuse	0.62	0.63	0.62
Radiation	0.99	0.76	0.60
Unmeasured	1.50	1.50	1.50
Total Losses (%)	17.15	16.75	15.85
Boiler Efficiency (%)	82.85	83.25	84.15

was operated with an average O_2 level of 3.54%. The final steam temperature was 891 °F (477 °C) at a pressure of 881 psig (6074 kPa). The boiler bank gas outlet temperature was 674 °F (357 °C) and the air heater gas outlet temperature was 336 °F (169 °C). The attemperation heat absorption was 21 10^6Btu/hr (6.2 MW_t). The heat absorption ratios for the furnace, secondary superheater, primary superheater, and generating bank were 1.01, 0.95, 1.00, and 0.93, respectively. The boiler efficiency, calculated by the heat loss method, was 85.13%, with dry gas heat loss accounting for 5.95%, and moisture from combustion of H_2 in the fuel resulting in a 4.11% loss. Under GR at full load with 24% gas heat input the average boiler O_2 level was 4.02%. The final steam temperature under GR was 890 °F (477 °C) at a pressure of 882 psig (6081 kPa). The flue gas temperatures increased slightly over baseline to 677 °F (358 °C) at the boiler bank exit and 337 °F (169 °C) at the air heater exit. The steam attemperation rate rose slightly to 30 10^6Btu/hr (8.8 MW_t). The HAR for the furnace, secondary superheater, primary superheater and generating bank were 0.95, 1.05, 1.06, and 1.01, respectively. This reflects a shift in heat absorption with a reduction in the furnace and an increase by the convective heat absorbers. The boiler efficiency was reduced by less than 1%, to 84.20%. The change in efficiency resulted from a reduction in the heat loss from moisture in the fuel and an increase in heat loss due to moisture formed in combustion. A higher flue gas moisture content results from firing natural gas which has a higher hydrogen-to-carbon ratio than coal.

Under SI at full load and at a Ca/S molar ratio of 2.1, the unit was operated at a boiler O_2 of 4.06%. Under this condition the average final steam temperature was 897 °F (481 °C) at a pressure of 885 psig (6102 kPa). The temperature is higher than under either of the previous two cases, which is likely due to operating at a higher control-room set-point. Flue gas temperatures increased to 741 °F (394 °C) at the exit of the boiler bank and to 396 °F (202 °C) at the air heater exit. The attemperation heat absorption was 19 10^6Btu/hr (5.6 MW_t). The HAR of the furnace, secondary superheater, primary superheater, and boiler bank were 1.04, 0.95, 0.97, and 0.77, respectively. These reflect an increase in heat absorbed by the furnace and reductions in convective heat absorption due to sorbent fouling, especially in the generating bank. The IK sootblowers were used almost continuously in order to maintain steam temperatures near the design point and limit upward excursions of flue gas temperature. The boiler efficiency was 83.43%, with the dry gas heat loss increasing to 7.52% of the heat input due to the rise in boiler exit gas temperature.

At full load, GR-SI operation was tested at an average gas heat input of 21%, Ca/S molar ratio of 1.7, and a boiler O_2 level of 3.79%. The final steam conditions were a temperature of 894°F (479°C) and a pressure of 881 psig (6074 kPa). The gas temperature increase was not as significant as in the SI case, with a boiler bank exit temperature of 686°F (363°C) and an air heater gas exit temperature of 343°F (173°C). The heat absorbed by the drum attemperator averaged 28 10^6Btu/hr (8.2 MW_t). The HAR of the furnace, secondary superheater, primary superheater, and generating bank were 1.04, 1.09, 1.06 and 1.04, respectively. This indicates that sootblowing was effective in maintaining cleanliness of the convective heat exchangers with enhanced heat transfer. The boiler efficiency was 1% less than the baseline case, at 84.15% on average. While the dry gas heat loss was essentially at the baseline level, the loss due to moisture in fuel dropped by 0.43% and the moisture from combustion of H_2 in the fuel increased by 1.54%.

The impacts of the three operating modes are compared to baseline impacts in Figures 5-62 through 5-73. Figures 5-62 through 5-65 show full load impacts, while Figures 5-66 through 5-69 considers mid load (25 MW_e) impacts, and 5-70 through 5-73 show low load (20 MW_e) impacts. Figure 5-62 shows that at full load, GR and GR-SI resulted in roughly a 1% decrease in boiler efficiency, while SI resulted in a 1.7% reduction due mainly to a significant increase in boiler exit gas temperature. The impacts on final steam conditions were minor, as shown in Figure 5-63. GR and GR-SI resulted in relatively small increases in steam attemperation rates, and corresponding reductions in the drum attemperator outlet temperature. These modes also resulted in increases in the steam temperature exiting the primary superheater, due to the

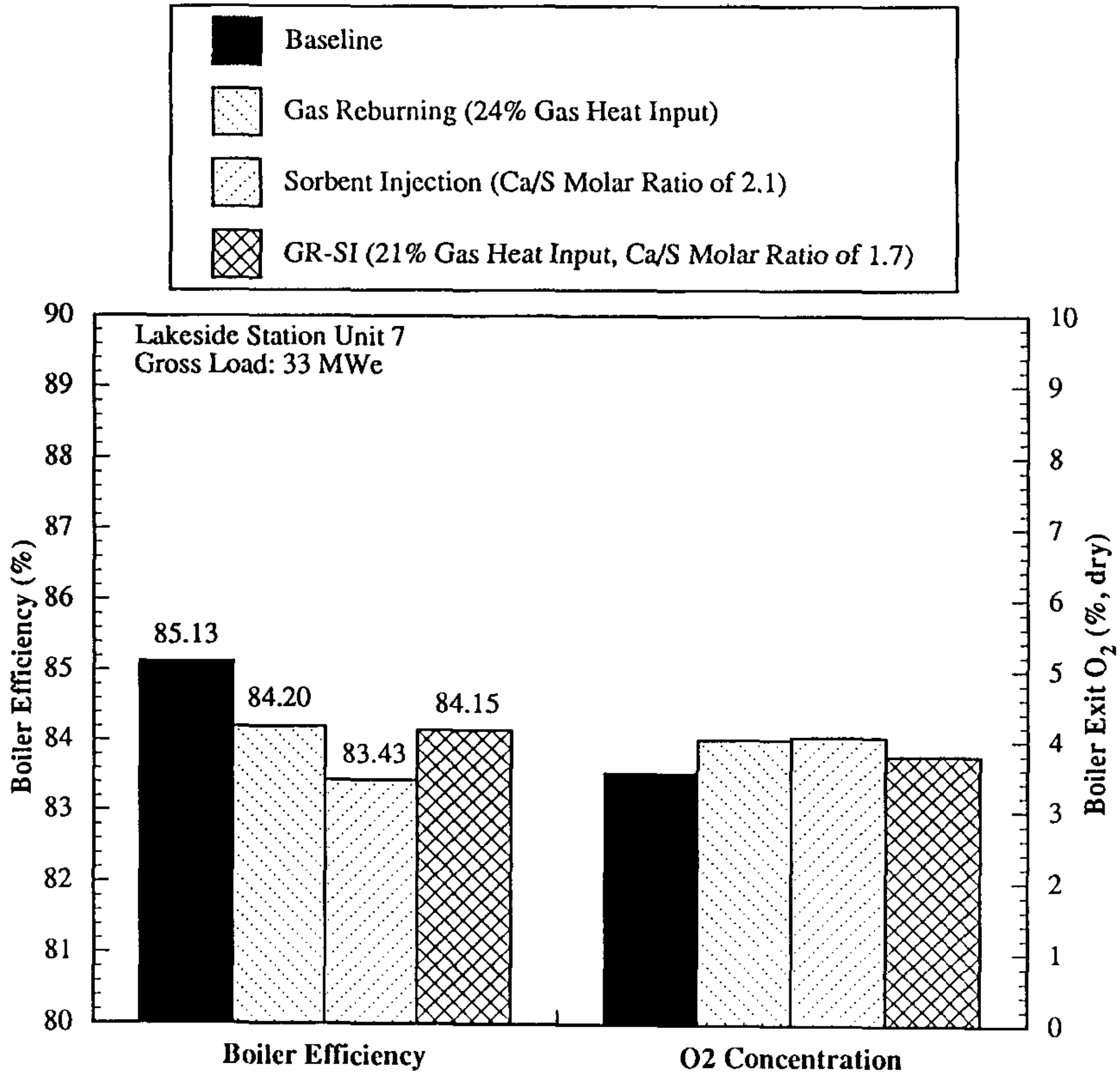


Figure 5-62. Boiler efficiency under full load Baseline, GR, SI, and GR-SI

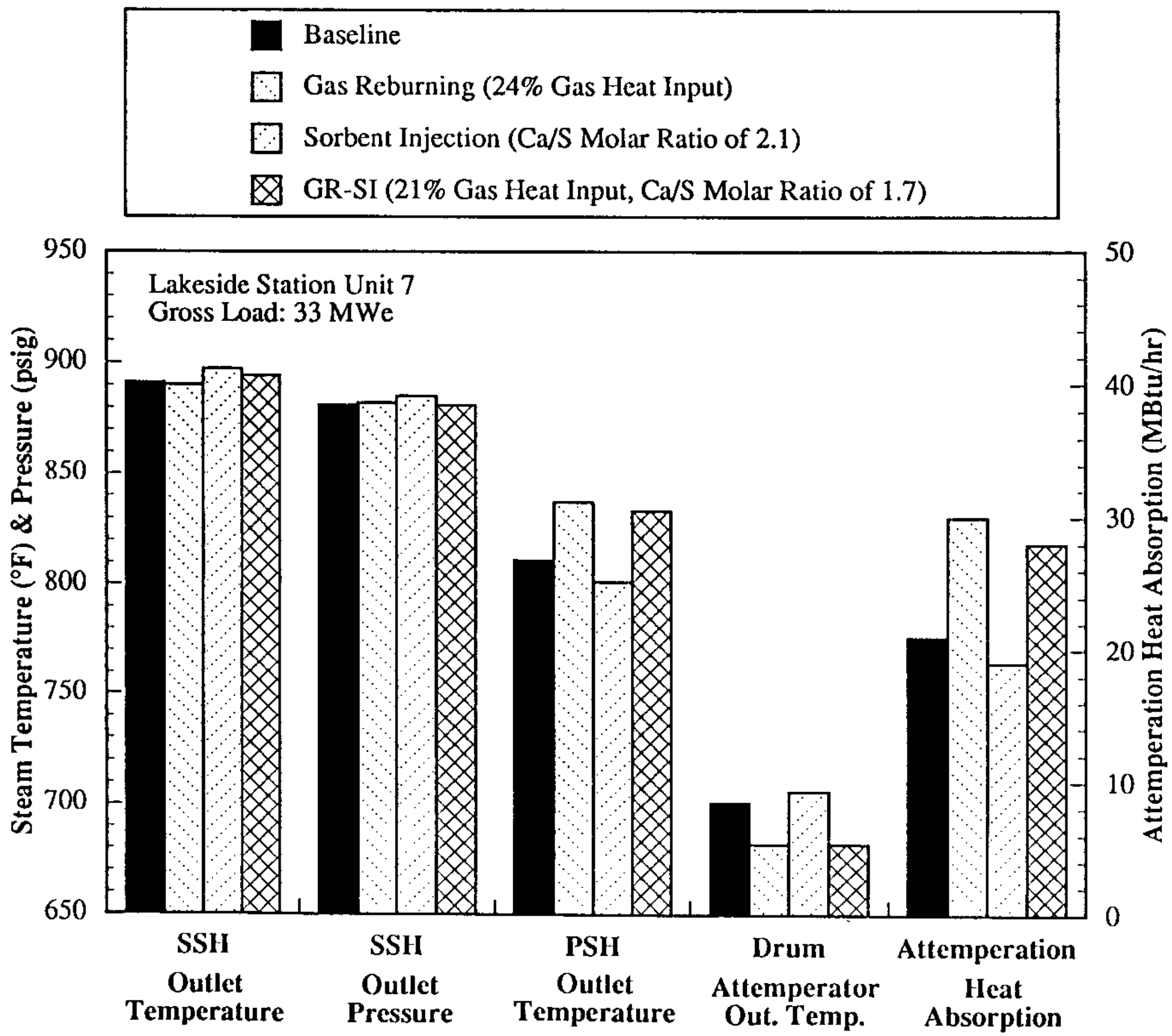


Figure 5-63. Steam conditions under full load Baseline, GR, SI, and GR-SI

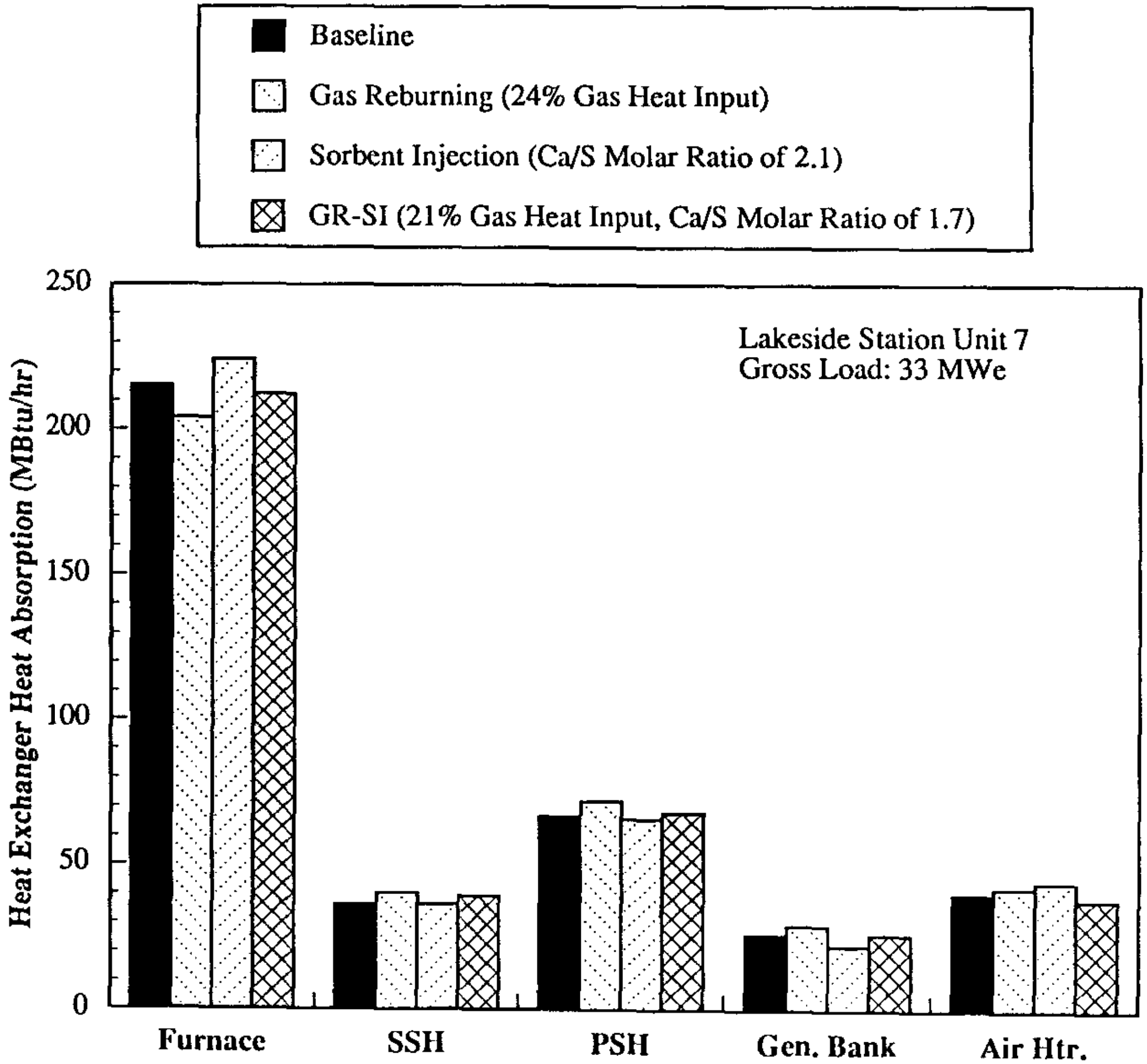


Figure 5-64. Heat absorption profiles under full load Baseline, GR, SI, and GR-SI

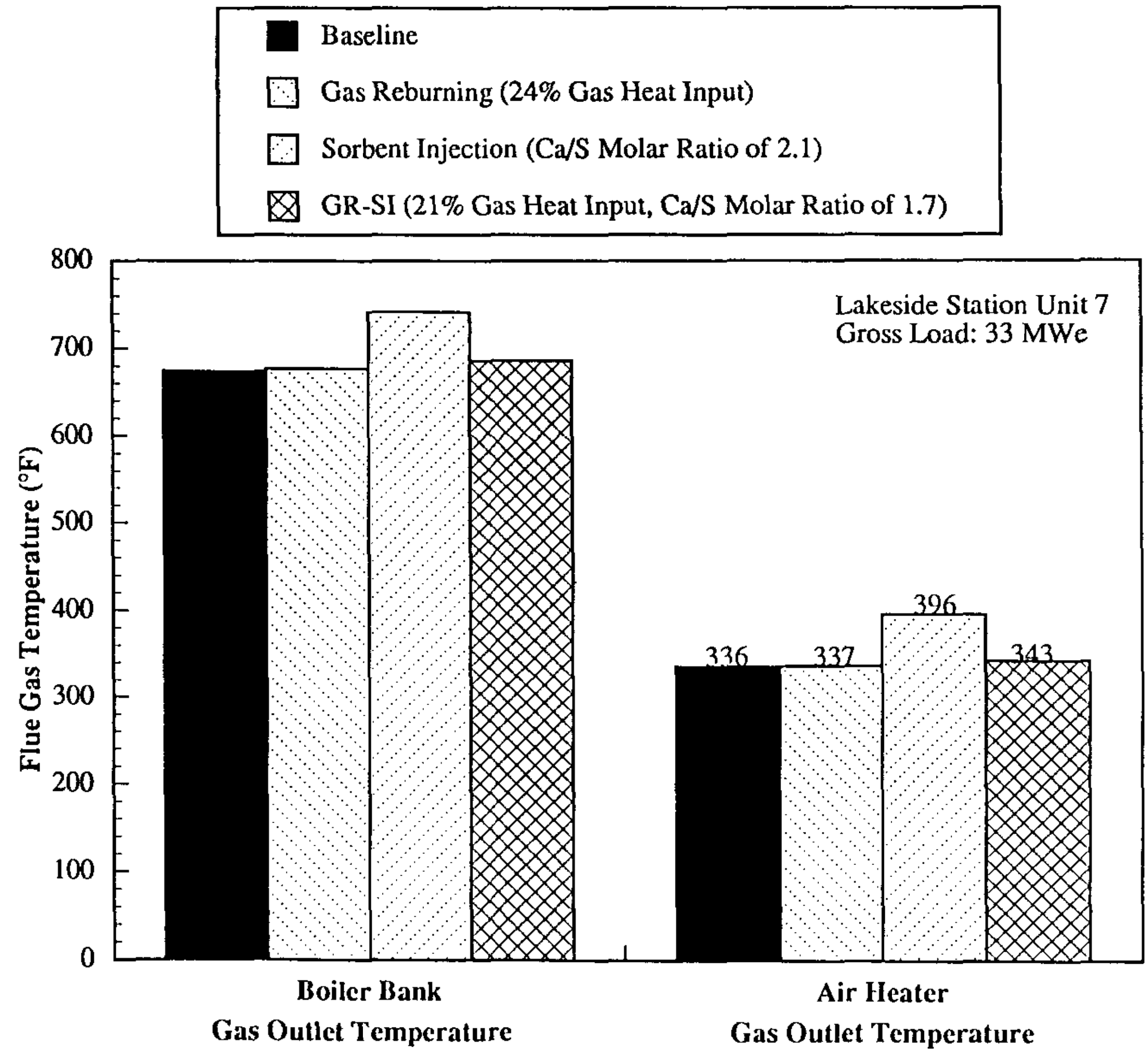


Figure 5-65. Flue gas temperatures under full load Baseline, GR, SI, and GR-SI

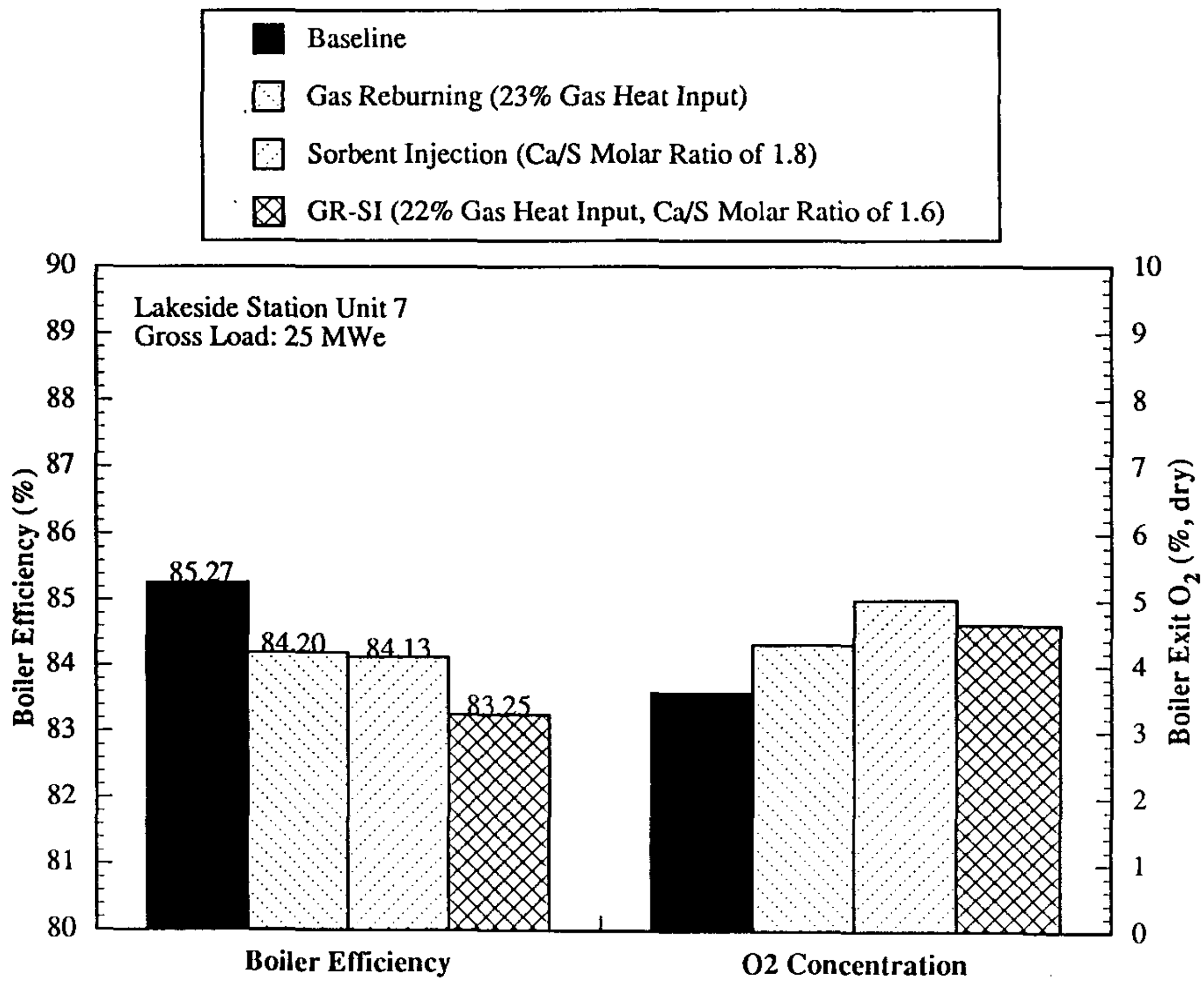


Figure 5-66. Boiler efficiency under mid load Baseline, GR, SI, and GR-SI

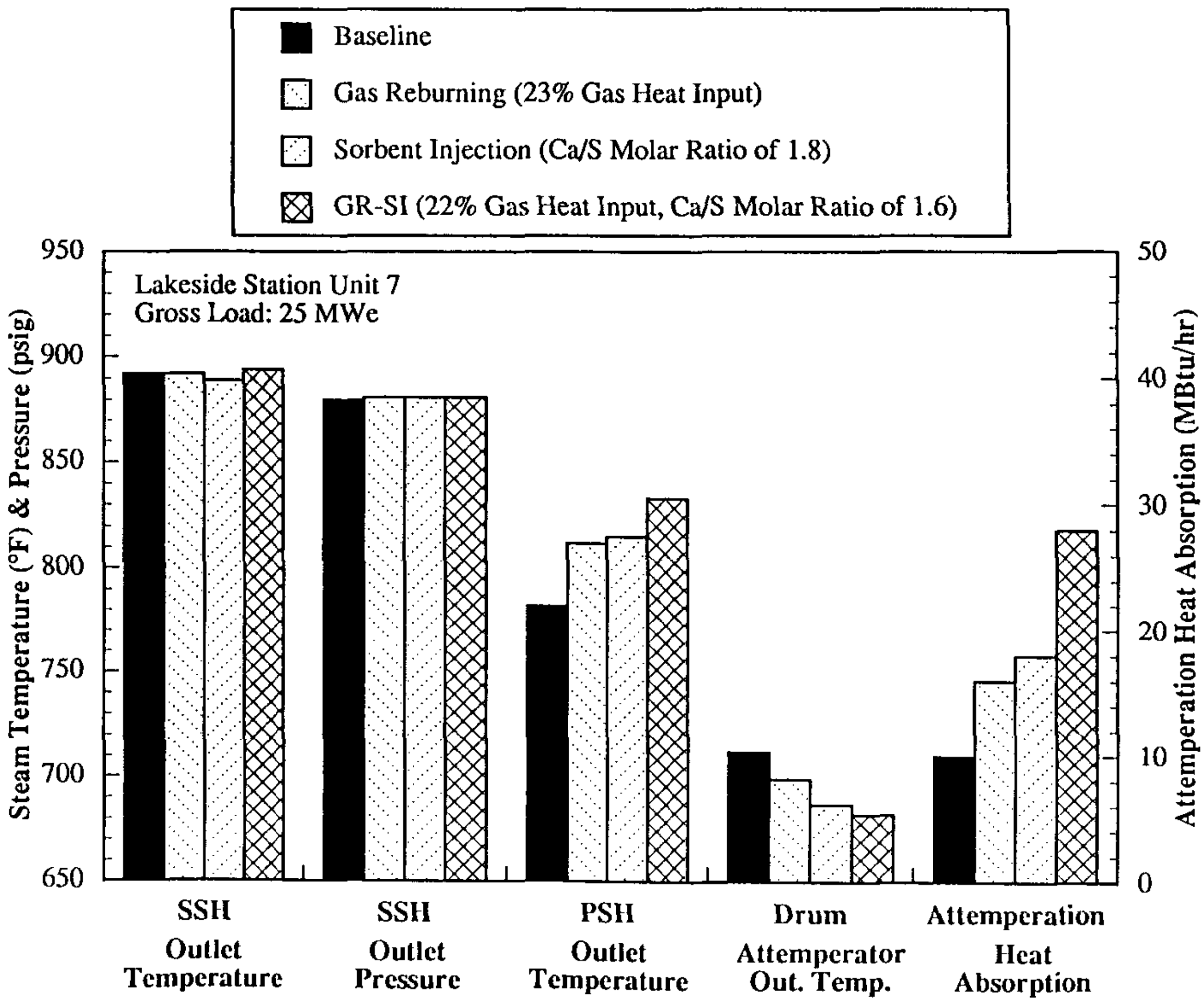


Figure 5-67. Steam conditions under mid load Baseline, GR, SI, and GR-SI

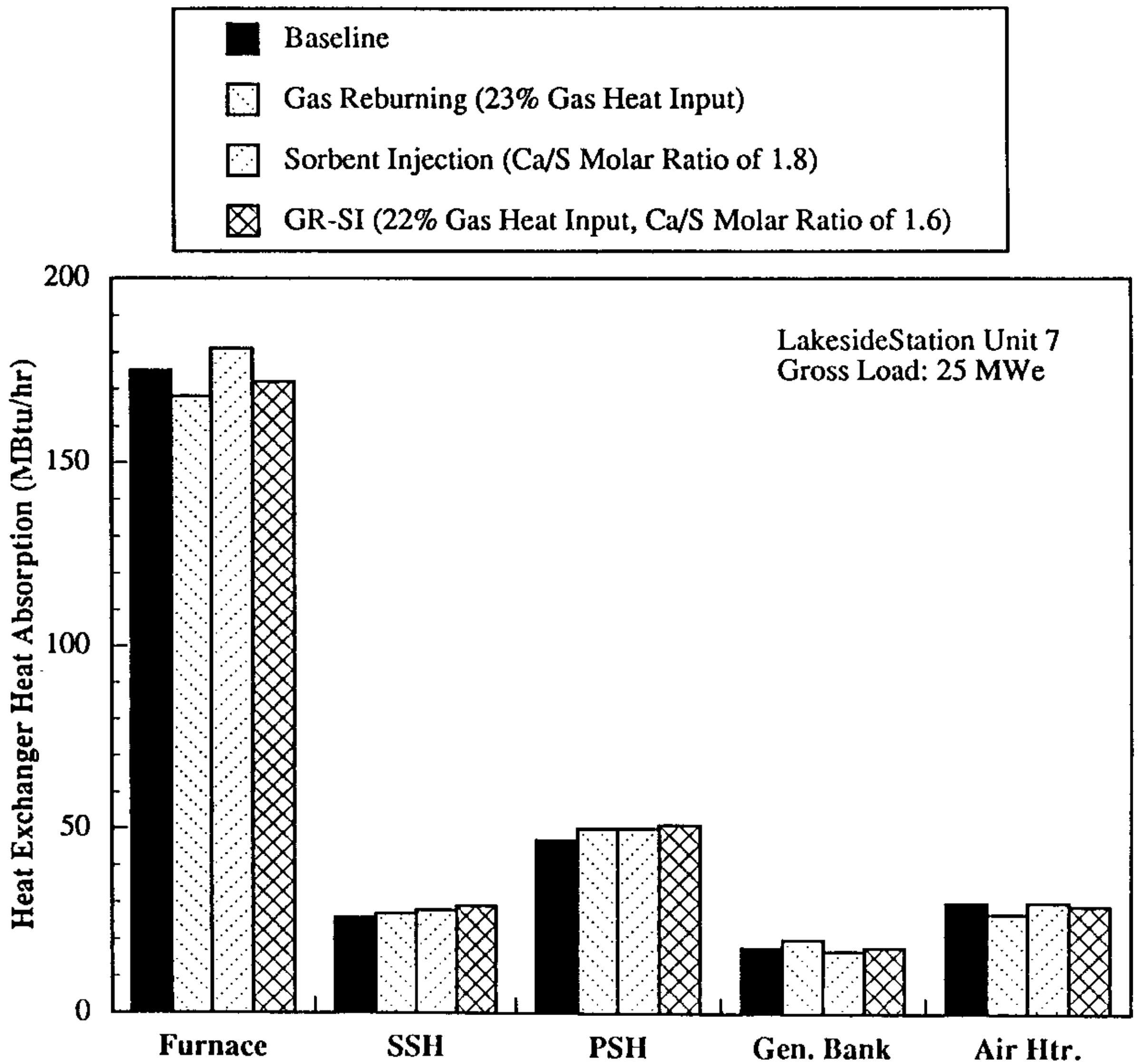


Figure 5-68. Heat absorption profiles under mid load Baseline, GR, SI, and GR-SI

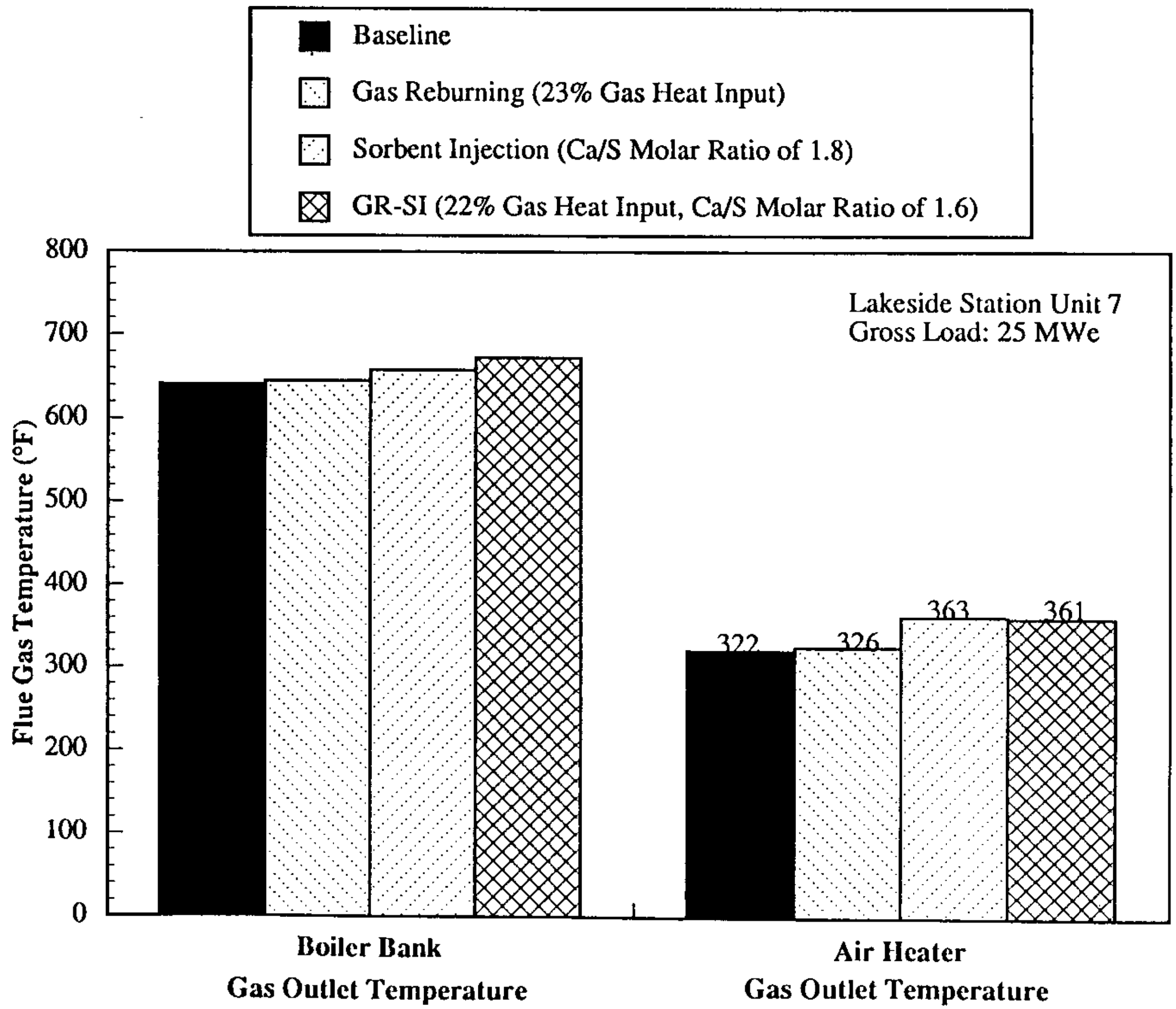


Figure 5-69. Flue gas temperatures under mid load Baseline, GR, SI, and GR-SI

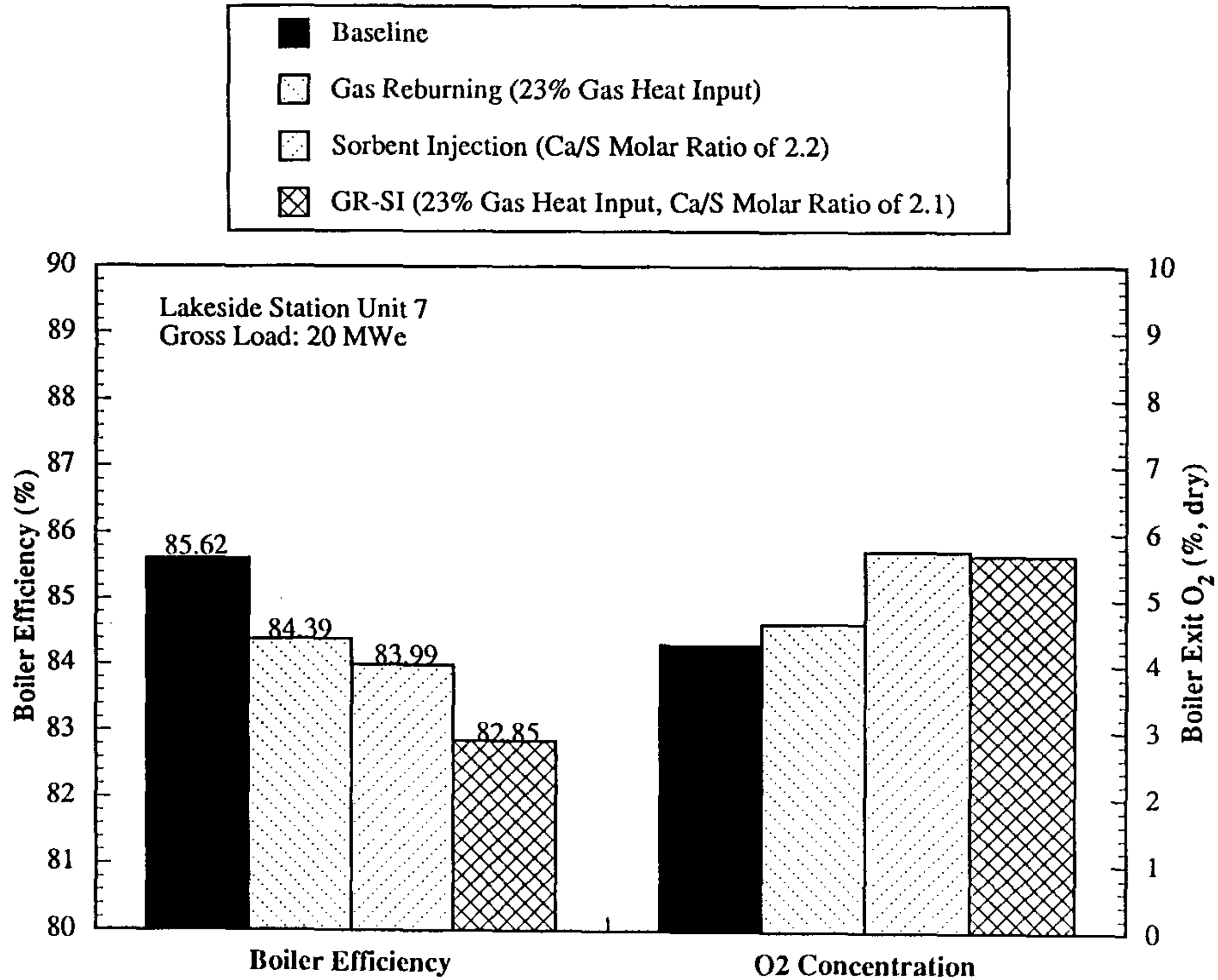


Figure 5-70. Boiler efficiency under low load Baseline, GR, SI, and GR-SI

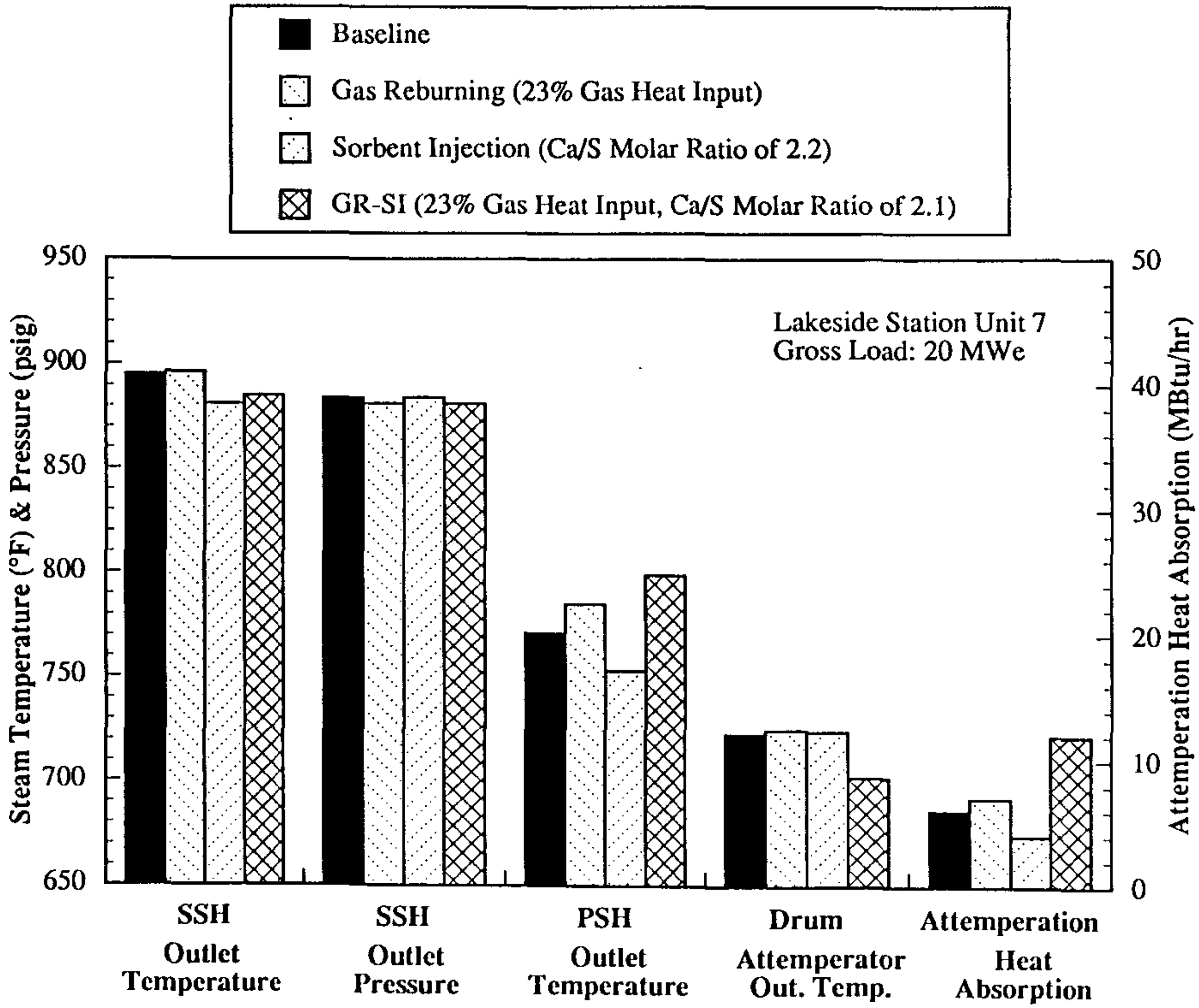


Figure 5-71. Steam conditions under low load Baseline, GR, SI, and GR-SI

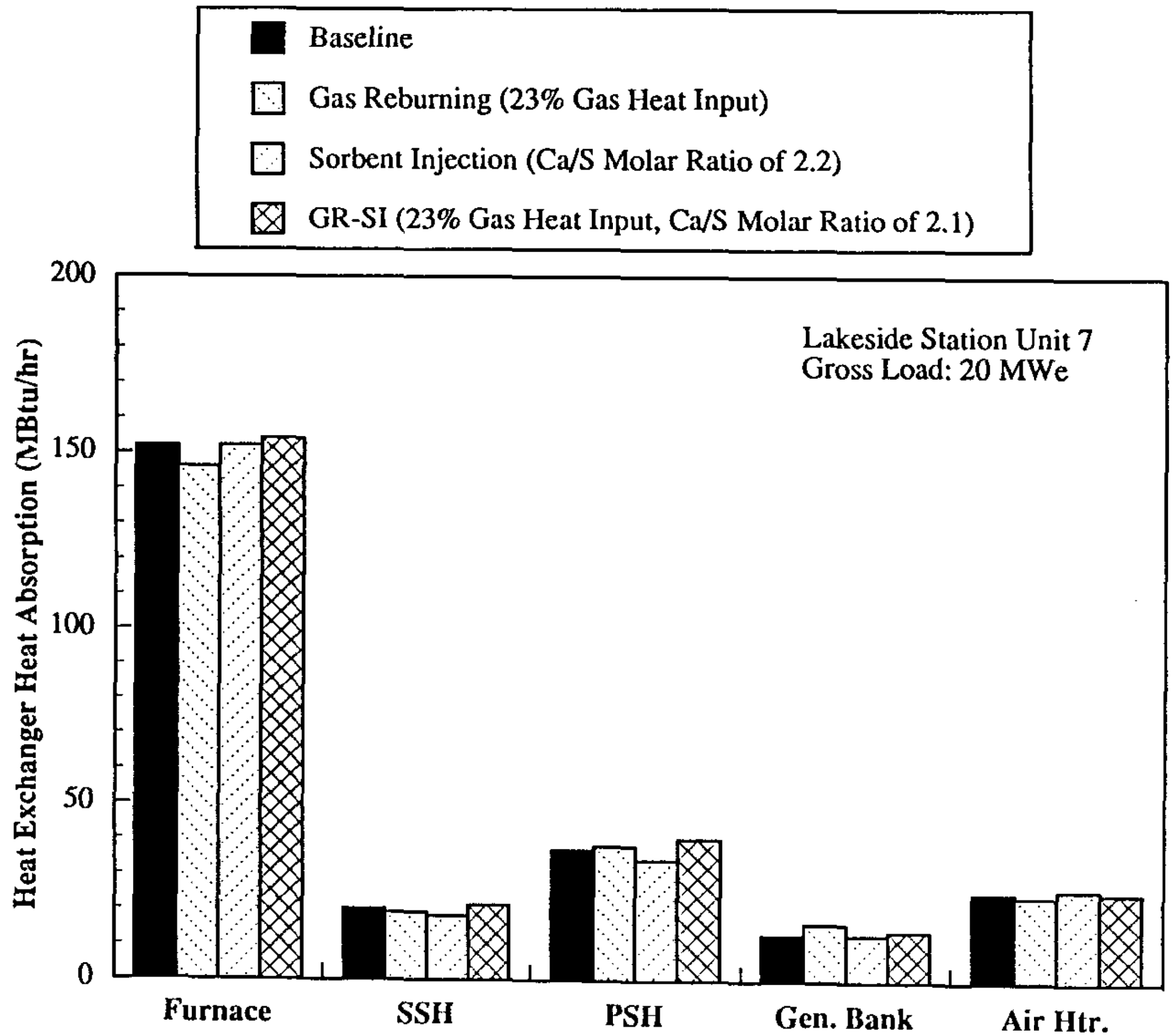


Figure 5-72. Heat absorption profiles under low load Baseline, GR, SI, and GR-SI

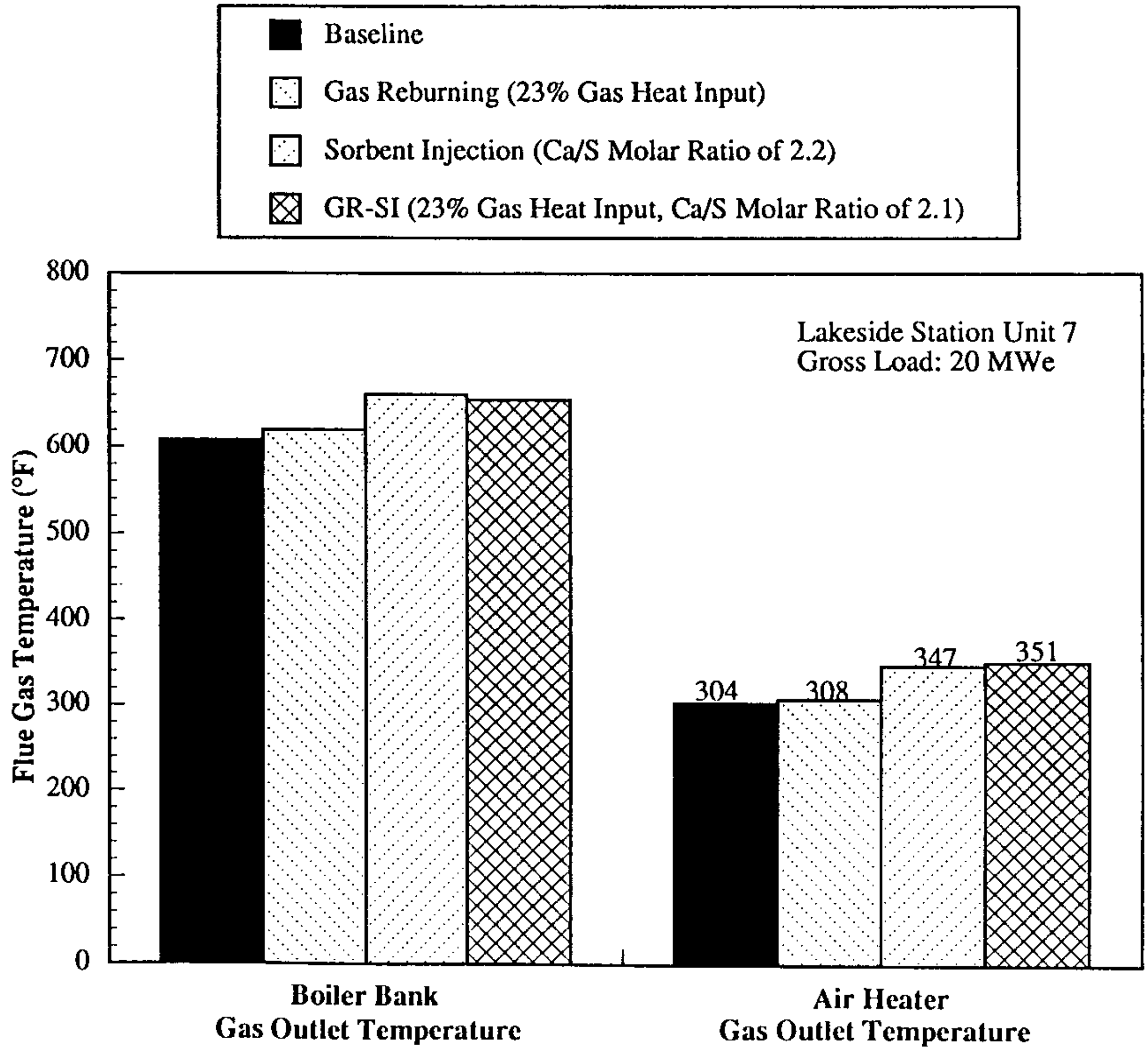


Figure 5-73. Flue gas temperatures under low load Baseline, GR, SI, and GR-SI

upward shift in the gas temperatures. Minor changes in the heat absorptions by the heat exchangers were measured, with GR resulting in a reduction in furnace heat absorption and an increase in convective pass absorption, while SI resulted in the opposite, an increase in furnace heat absorption and reduction in convective pass absorption. Figure 5-65 shows that the gas temperature at the exit of the air heater was most significantly increased by SI at a Ca/S of 2.1, while the impacts of GR and GR-SI (at a Ca/S of 1.7) were very minor.

Figure 5-66 shows the boiler efficiencies and O_2 levels at mid load. GR and SI resulted in efficiency reductions of 1.1 and 1.2%, respectively, while GR-SI resulted in a 2.0% reduction from the baseline. At mid load, the final steam conditions did not change significantly. However, as shown in Figure 5-67, increases in the steam temperature from the primary superheater and attemperation rate were measured for GR, SI, and GR-SI. Changes in heat absorption profiles were very minor, with GR resulting in a reduction in furnace heat absorption and SI resulting in an increase. Under SI and GR-SI, the gas temperature at the air heater exit increased by approximately 40°F (22°C), from a baseline of 322°F (161°C) to 363°F (184°C) and 361°F (183°C), respectively.

The thermal performance impacts at low load (20 MW_e) are shown in Figures 5-70 through 5-73. The thermal efficiency dropped more sharply in the higher load cases, due to more significant increases in boiler O_2 level under SI and GR-SI. The baseline efficiency of 85.62% was reduced to 84.39% under GR, 83.99% under SI, and to 82.85% under GR-SI. The baseline boiler O_2 concentration of 4.31% increased to 4.63% under GR, 5.74% under SI, and 5.67% under GR-SI. Final steam temperatures were higher under baseline and GR at 895°F (479°C) and 896°F (480°C) respectively, compared to 881°F (472°C) and 885°F (474°C) under SI and GR-SI respectively. Steam attemperation rates were low at this load, with a maximum at 12 10^6Btu/hr (3.5 MW_t) under GR-SI. This indicates that higher steam temperature could have been achieved under this condition by adjustment of steam temperature controls.

The gas temperature exiting the air heater increased when injecting sorbent, from a baseline to 304°F (151°C) to 347°F (175°C) under SI and 351°F (177°C) under GR-SI.

Limited evaluation of fly ash combustible matter was undertaken during the test program. In cyclone-fired units, roughly 20% of the ash input to the unit is converted to fly ash, with the majority of the ash tapped through the slag tap. Therefore, the combustible matter in ash corresponds to a much smaller heat loss than in pulverized coal-fired units. The fly ash combustible matter content for baseline and GR operation are shown in Figure 5-74 for three loads. The baseline data, obtained during the 1991 baseline test, indicated a range of 2% to 8%. Under GR, the fly ash carbon content increased from 12 to 14% over the range of gas heat inputs of 15 to 25%. At full load, GR had a smaller effect, with fly ash carbon content increasing from 7 to 10%. While in pulverized coal-fired units an increase of 5% in carbon-in-fly ash results in a 1% increase in heat loss, for cyclone-fired units an increase of 20% in carbon-in-fly ash results in a 1% increase in heat loss.

5.2.6 Impacts of GR, SI, and GR-SI on Other Areas of Boiler Operation

In this section the impacts of the co-application of GR and SI on boiler performance areas other than heat transfer efficiency are discussed. These include furnace slagging, convective pass fouling, and ESP performance.

In order to assess the impact of gas GR-SI on the boiler, a series of inspections were performed both prior to and following the GR-SI testing. EER established the baseline condition of the unit and determined the existence and rate of both degradation and equipment failures. The following areas were evaluated:

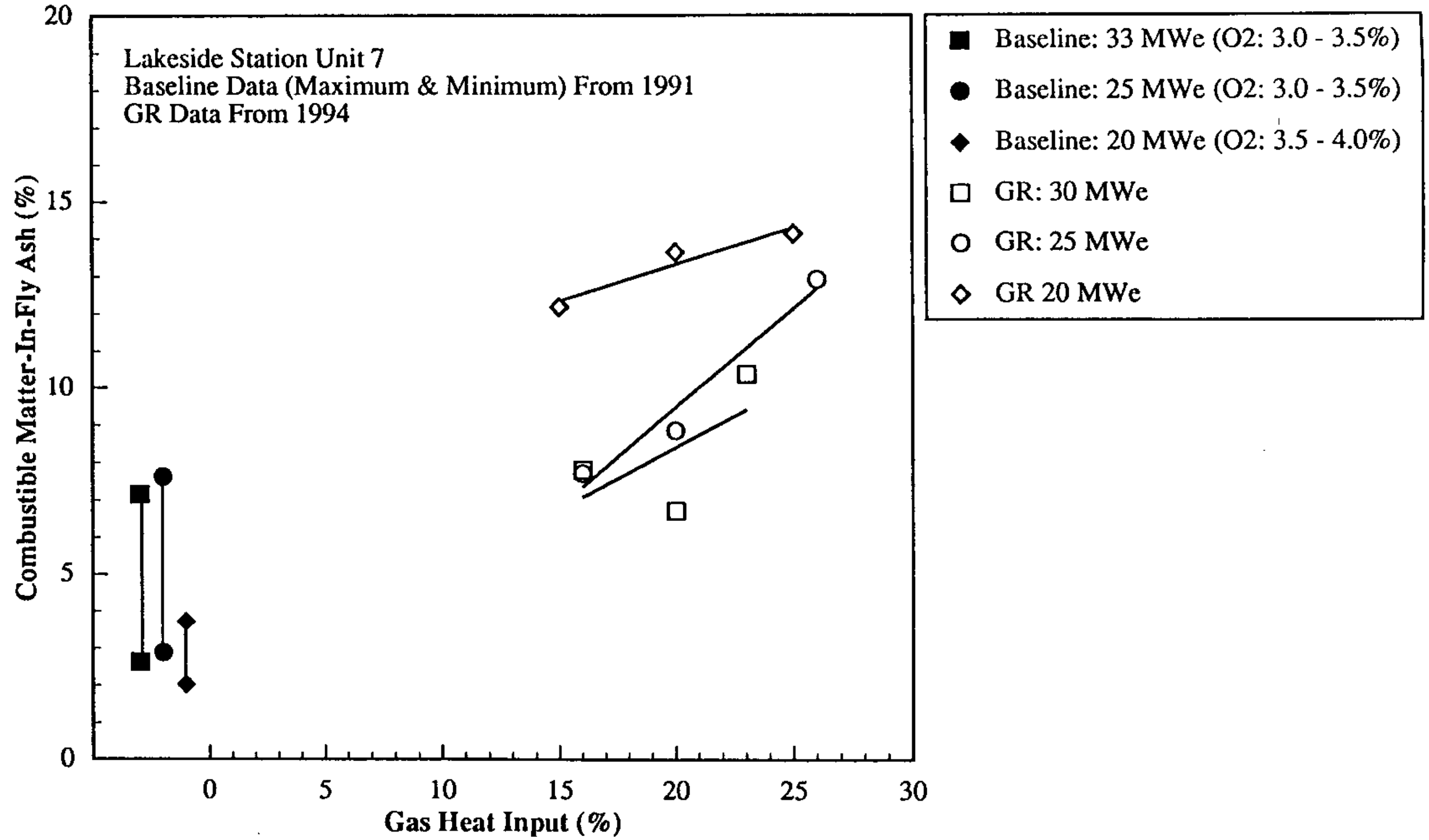


Figure 5-74. Comparison of combustible matter-in-fly ash under Baseline and GR

- Boiler tubes
- Regenerative air heater
- Electrostatic precipitator
- Chimney
- Boiler performance

These areas are discussed in detail in the GR-SI Boiler Impact Report.

5.2.6.1 Slagging

Slagging in the furnace was evaluated by visual inspection of furnace conditions. In coal-fired units, buildup of slag on furnace walls is generally dependent on coal qualities such as ash fusion temperatures and boiler operating parameters such as stoichiometric ratio (excess air), gas temperature profile, and furnace wall temperatures. In the design of units, slag buildup is minimized by requiring high furnace volume, limiting heat input per plan area, and limiting the Furnace Exit Gas Temperature (FEGT). Since ash fusion temperatures are lower under reducing conditions, areas in the furnace which are deficient in excess air may have increased slag buildup. In cyclone-fired units a slagging type coal is used, i.e. with low ash fusion temperature, in order to tap molten slag through the bottom of the furnace. Typically, only 20% of the ash input to cyclone-fired units forms fly ash; the majority of the ash is removed through the slag tap.

It was found through observation that the injection of natural gas and FGR promoted formation of slag patterns, i.e. there were slag accumulations around the nozzles forming "eyebrows" and on the waterwall areas above the natural gas/FGR injectors. Slag deposits were observed up to the rear section of the furnace wing walls. The sloped front wall and the upper furnace were generally free of slag, with the exception of the lower portion of the east front wall division panel.

A cleaning feature was incorporated in the GR system design, which allowed for the nozzles to be rodded out as needed to remove slag deposits on the nozzle periphery. At the beginning of each test day, the accumulations and the necessity for rodding out were assessed. Usually small amounts of slag deposits were removed weekly. The small natural gas only injectors, which were not in use during the long-term demonstration, were found to be completely obstructed.

5.2.6.2 Convective Pass Fouling

Fouling of the convective pass due to GR-SI was quantified through heat absorption ratios (HAR) calculated by the BPMS. The HARs are not direct indicators of the extent of fouling since they do not take into account temperature changes which drive heat transfer. HAR for the secondary superheater, primary superheater, and generating bank for a GR-SI test, conducted on April 6, 1994, are shown in Figure 5-75. The data presented in this figure were calculated every five minutes over the test period. In this test, GR operation was initiated at 10:15 AM, while SI was initiated at 11:15 AM. It is evident that the increased upper furnace gas temperature due to reburning fuel heat input above the coal cyclones and the nearly continuous sootblowing used during SI operation resulted in enhanced heat absorption by the secondary and primary superheaters. For these heat exchangers the HAR's were consistently above 1.0. The generating bank HAR was, however, below 1.0 in many cases. Figure 5-76 shows the flue gas temperatures at the inlet and exit of the boiler bank and at the exit of the air heater. As is evident in this figure, initiation of SI resulted in upward shifts in gas temperatures at these locations. The temperature shifts of 30°F (17°C) to 40°F (22°C) are near to those quoted earlier for mid load GR-SI operation. Under SI, IK sootblowers were in operation between 80 to 90% of the time.

5.2.6.3 ESP Performance

The performance of the ESP was determined through particulate sampling according

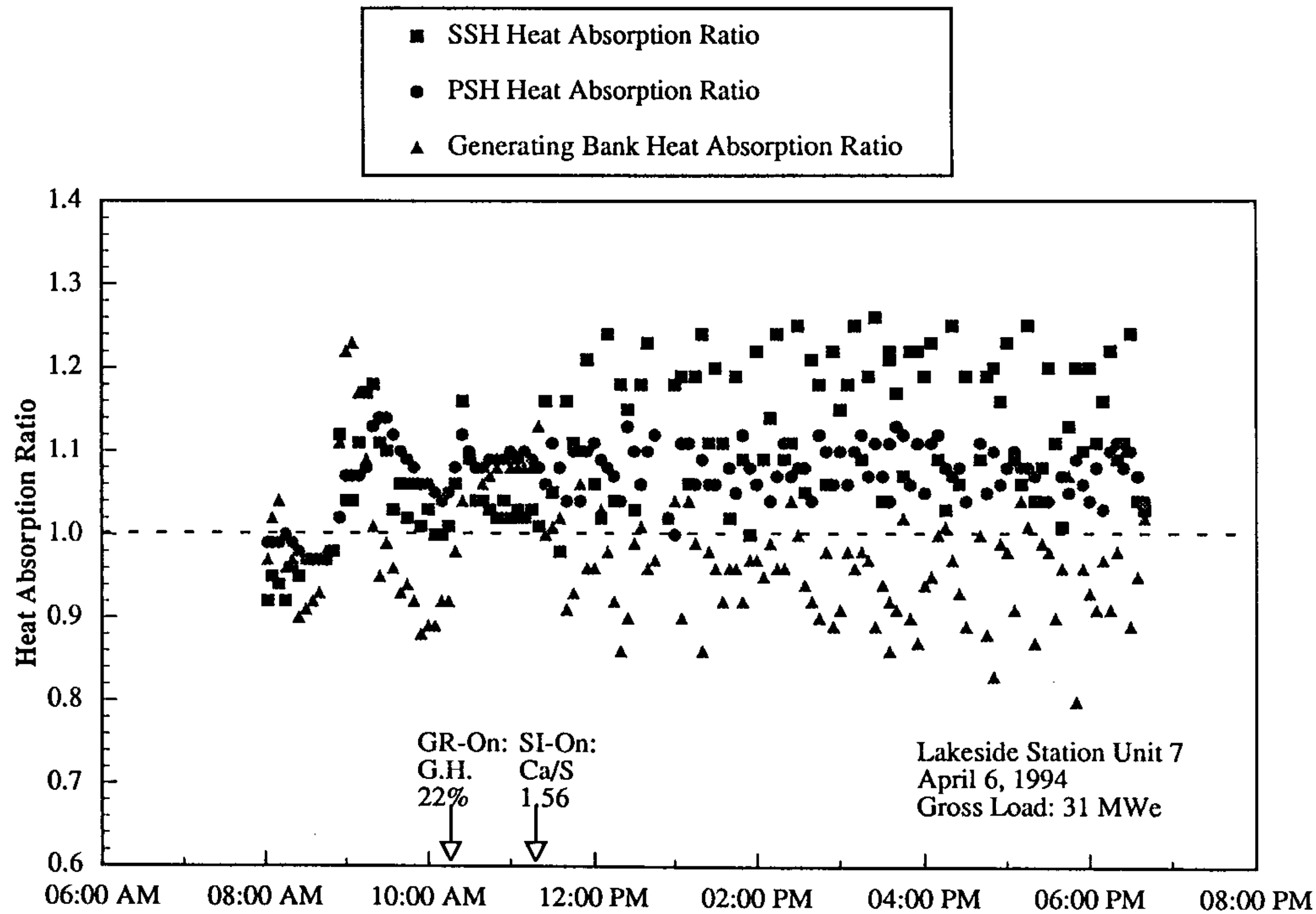


Figure 5-75. Heat absorption ratios under GR-SI operation.

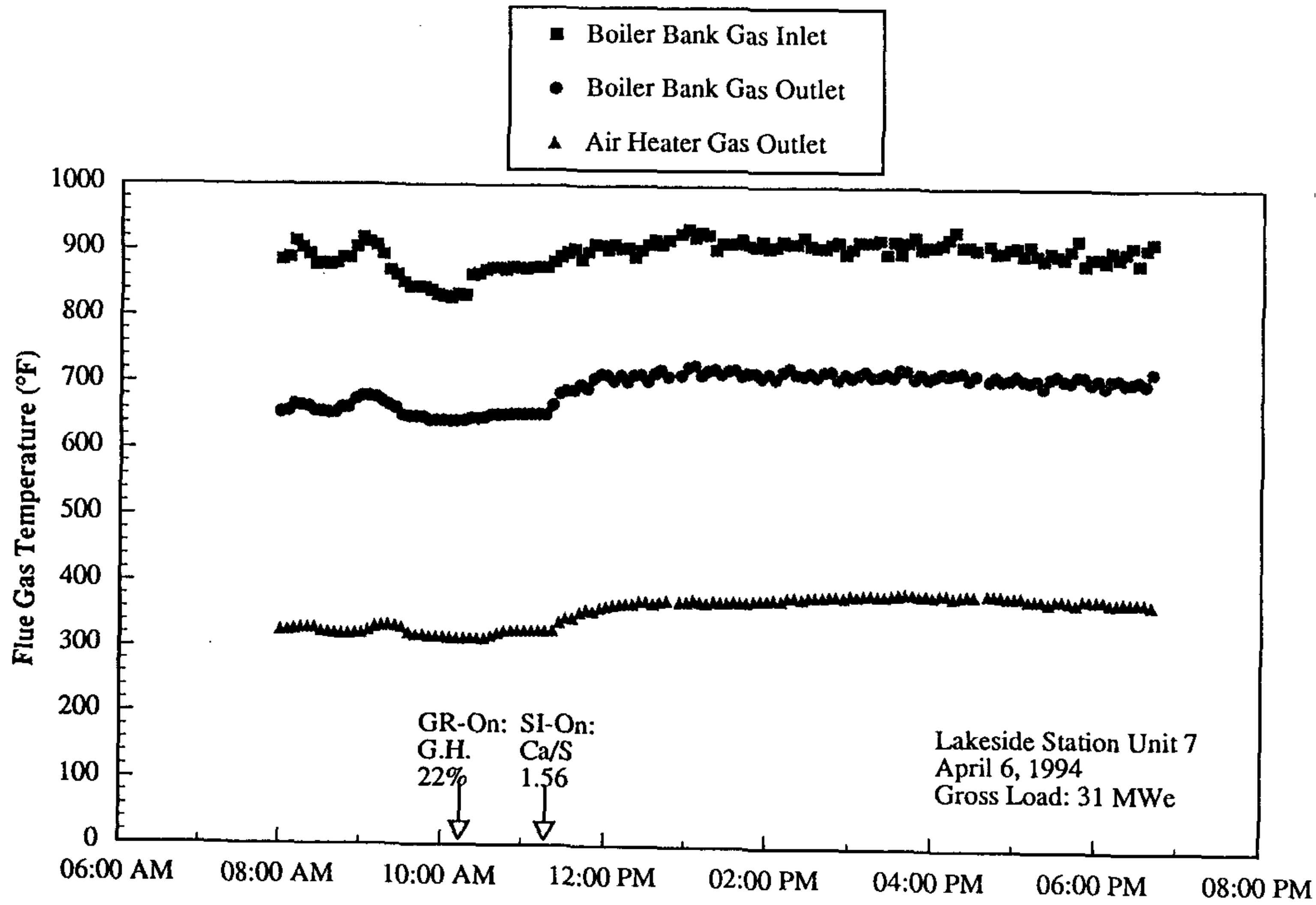


Figure 5-76. Flue gas temperature profile under GR-SI operation.

to U.S. EPA Method 5 while the unit was under full load GR-SI operation. The sampling data are summarized in Table 5-19. The average particulate emissions were 0.016 lb/10^6Btu (6.9 mg/MJ) far below the 0.1 lb/10^6Btu (43 mg/MJ) limit, with an average grain loading of 0.0080 gr/dscf (0.018 g/m^3). The grain loading is somewhat higher than that measured under baseline operation in 1988. In those tests, with both units 7 and 8 operating at full load (66 MW_e total), the average grain loading for three runs was 0.0036 gr/dscf (0.0082 g/m^3). The flue gas moisture content, which may impact the acid dew point temperature and hence metal corrosion rate, averaged 11.46% by volume. This is an increase from the baseline flue gas moisture content of 8.89%. Inspections of the ESP were conducted by contractors to determine its condition prior to initiation and after completion of the GR-SI testing. The findings are described below in the boiler inspections section.

5.2.6.4 GR-SI System Auxiliary Power

Measurements of auxiliary power consumed by the GR-SI system were not made regularly, i.e. at intervals during GR-SI testing. However, an estimate of auxiliary power usage has been made based on equipment power rating. This indicates that GR operation consumed approximately 350 kW while SI operation required 362 kW. Therefore, the estimated total auxiliary power usage by GR-SI is 712 kW. Since these are maximum power usages based on equipment rating, i.e. the actual power consumption should be less especially under reduced loads. These also do not directly reflect the change in total auxiliary power consumed by Unit 7.

5.2.7 GR-SI Demonstration Troubleshooting

Adjustments made to boiler and GR-SI system operation are addressed in this section. In general, the GR-SI equipment performed well after early optimization. Several problems were encountered during start-up which required attention from CWLP or an outside contractor. These included the FGR fan, rear pass hoppers, flue gas leakage,

TABLE 5-19. PARTICULATE MATTER SAMPLING UNDER GR-SI AT FULL LOAD

Test Run	1	2	3	Avg.
Sampling Location	Stack	Stack	Stack	
Test Date	2-Jun-94	2-Jun-94	2-Jun-94	
Sampling Period	10:45-11:55	13:11-14:18	14:46-15:53	10:45-15:53
Particulate Concentration				
grains/acf	0.0048	0.0058	0.0034	0.0047
grains/dscf	0.0081	0.0100	0.0059	0.0080
Emissions Rate				
pounds/hour	9.47	10.58	6.23	8.76
pounds/MBtu (F = 9,780)	0.016	0.019	0.012	0.016
Average Volume Flow Rate:				
@ Flue Conditions, acfm	231,172	212,144	214,753	219,356
@ Standard Conditions, scfm	136,174	123,393	123,553	127,707
Gas Temperature (°F)	324	327	331	327
Gas Velocity (ft/s)	21.8	20.01	20.25	20.69
Moisture Content (%, Volume)	10.73	11.58	12.06	11.46

and sootblower operation. In addition to problems in these areas which were rectified during start-up, several problems were encountered during operation over the nine month demonstration period. Adjustments/repairs were needed in the operation of flame scanners, cyclone air transmitters, the WDPF control system, and the ash handling system.

During start-up, adjustments were made to the FGR fan, the rear pass hoppers, the retractable sootblowers and to the boiler insulation. The FGR fan clutch failed twice necessitating repair. Once adjustments to the drive and control system were made, few problems with the FGR fan were encountered throughout the rest of the testing program. The rear pass hoppers tended to plug up. When the material was dislodged, some of the ash would flow through an opening in the floor to the base of the FGR fan and interfere with the spring suspension mounts. A metal box was installed in this opening to capture the ash and hence prevent its buildup near the FGR fan mounts. All of the retractable sootblowers were replaced during the construction phase of the project. Early problems with sagging and misalignment were corrected by the CWLP boiler crew. These efforts were successful, and the sootblowers were used almost continuously while injecting sorbent. The boiler insulation had cracks in several areas necessitating asbestos abatement, repair of cracks, and installation of mineral wool based insulation. Since the unit is a positive pressure design, these cracks resulted in outward leakage of gas before they were repaired.

During GR-SI operation several operational problems were encountered. One problem was a shutdown of the reburning system from the cyclone flame scanner signal. One of the requirements of continued reburning operation was that both cyclones be in operation. If the cyclone flame scanner did not detect the presence of a flame, then the coal feeder and natural gas valves would trip. This problem was corrected by a Forney field service representative, who found several problems including incorrect installation and recommended an increase in the flow of purge air.

Another area where adjustments were made was with the indicated cyclone air flow. The original cyclone air transmitters were not well temperature compensated, resulting in inaccuracy in the flow measurement. The air flow transmitters were replaced by a "smart" air flow transmitter manufactured by Rosemount, which corrected the flows according to the air temperature. After these transmitters were installed, the process efficiency and repeatability greatly improved.

The area which required greatest attention was the ash handling system. On one occasion a serious tube leak occurred in the boiler bank. When the operators detected the leak they pulled all of the ash hoppers. Since the ash was being conveyed to the ash silo instead of the sluice pond, significant problems arose. The moisture with the ash resulted in formation of cementitious material when it contacted the free lime in the silo. This material required two months of work to clean out. Another problem relating to the disposal of ash was with the addition of water to the ash when it was loaded onto trucks. This process was not properly controlled, therefore the ash either had too little moisture (was too dusty) or too much moisture. A third problem relating to the ash handling system was with the lock hopper valves. These valves, which were essentially plates of 1/8" to 3/16" (3.2 to 4.8 mm) in thickness, wore out due to ash erosion. This led first to frequent high level alarm and later to caking of ash on baghouse screens and destruction of these screens. Eventually, both the valves and screens were replaced.

6.0 ENVIRONMENTAL PERFORMANCE

6.1 Hennepin GR-SI Demonstration

Environmental monitoring was conducted during each Phase of the project to determine pre-project (baseline) environmental impacts of operating Hennepin Unit 1 and impacts due to GR-SI. The monitoring during Phases I (Design and Permitting) and II (Construction and Start-Up) was limited to compliance monitoring of coal analyses, ash sluice system water analysis, and emissions monitoring (NO_x, O_2, CO) to develop a GR-SI system design basis. The Hennepin Station was operating under two permits issued by the Illinois Environmental Protection Agency (IEPA). The air emissions source permit limits emissions of SO_2 while the NPDES Permit regulates the pH, oil and grease, and total suspended solids (TSS) in the water discharged to the Illinois River. The compliance monitoring was continued in Phase III (Operation, Data Collection, Reporting and Disposition) and was supplemented with other measurements. These included monitoring of gaseous emissions NO_x, SO_2, CO, CO_2, and hydrocarbons, N_2O, particulate loading and size distribution, fly ash resistivity, and opacity.

Permitting requirements were considered with respect to the original pre-project permits issued by the IEPA and modifications required to construct the GR-SI system and evaluate its performance. A permit to construct was granted by the IEPA, which addressed a range of issues including a return to pre-project emissions. This was of concern because of the potential application of New Source Performance Standards (NSPS) or Prevention of Significant Deterioration (PSD) provisions of the Clean Air Act Amendments (CAAA) to the unit.

During the year-long GR-SI demonstration, environmental impacts were evaluated. The primary waste product from GR-SI operation is a high calcium solid waste, which is a mixture of coal ash, spent sorbent, and unreacted sorbent. During nominal GR-SI operation this solid waste is produced at a rate approximately twice the rate of normal fly ash production. An evaluation of several alternative solid waste handling methods was undertaken and it was decided to sluice the ash directly to the existing pond and to use CO_2 injection to control the pH to an acceptable range (6 to 9), as required by the state EPA's National Discharge Elimination System (NPDES) Permit Regulation.

To ensure that the water quality and air quality were acceptable, an extensive environmental monitoring program was put into effect. The environmental measurements were outlined in an Environmental Monitoring Plan (EMP), prepared by EER, and distributed to project sponsors.

6.1.1 Environmental Monitoring Results

The purpose of environmental monitoring was to ensure that GR–SI operation was conducted in an environmentally acceptable manner and to obtain a data base of environmental parameters for consideration in future application of the GR–SI technology. The monitoring in Phases I and II entailed compliance monitoring of ash sluice discharge water, coal analyses, and limited emissions characterization for the purposes of GR–SI process design. The Phase III monitoring was directed primarily at obtaining a full range of measurements to verify process efficiency and any impacts on gaseous or liquid discharges. The measurements of NO_x and SO_2 emissions were of primary importance to verify that project target emissions reductions were met. Other measurements were used to characterize combustion efficiency, ESP performance, and other pollutants which were of concern in applying GR–SI to a coal fired unit. EPA reference methods were used to verify the accuracy of continuous emissions measurements.

Gaseous emissions were measured continuously during GR, SI, and GR-SI operation from a sampling grid at the economizer inlet and at the breeching. The CEMS (Continuous Emissions Monitoring System) met the requirements of U.S. EPA Methods

3A "Determination of Oxygen and Carbon Dioxide Concentrations in Emissions From Stationary Sources," 6C "Determination of Sulfur Dioxide Emissions from Stationary Sources," 7E "Determination of Nitrogen Oxides Emissions from Stationary Sources," and 10 "Determination of Carbon Monoxide Emissions from Stationary Sources." Particulate matter emissions were evaluated primarily with a plant opacity meter, which transmitted data continuously to the BPMS. At the conclusion of the GR-SI demonstration, stack particulate matter emissions were measured manually according to U.S. EPA Method 5, "Determination of Particulate Emissions From Stationary Sources." Aqueous discharges were tested regularly by plant personnel, as dictated by the NPDES permit.

Table 6-1 summarizes the gaseous emissions under GR-SI operating conditions, over the Phase III demonstration period. From January 10, 1992 to October 19, 1992, GR-SI operation was conducted for 557 hours. GR-SI was operated at an average gas heat input of 18.2% and a Ca/S of 1.76. Reductions in SO_2 emissions were calculated from the 5.3 lb/10^6Btu (2,280 mg/MJ) baseline and reductions in NO_x were calculated from the 0.75 (lb/10^6Btu) (323 mg/MJ) baseline.

Under GR-SI the NO_x emissions were reduced to 0.246 lb/10^6Btu (106 mg/MJ), a 67.3% reduction, and SO_2 emissions were reduced to 2.51 lb/10^6Btu (1080 mg/MJ), a 52.6% reduction. The SO_2 reduction reflects a 18.1% reduction due to natural gas switching and a further reduction of 42.1% due to SI. The sorbent calcium utilization in this case was 24.1%. Emissions of CO_2 averaged 14.5%, which is a reduction of 7.1% from the coal baseline of 15.6% CO_2. CO emissions averaged 57 ppm (@ 3% O_2). In general, CO emissions were lowest during high-load tests and increased to above 100 ppm for tests in the 45 to 50 MW_e range. Operation at loads of 72 to 75 MW_e typically resulted in emissions below 20 ppm. Under normal short-term GR-SI operation with humidification, ESP performance was adequate to maintain particulate emissions below 0.1 lb/10^6Btu (43 mg/MJ) and stack opacity levels below the 30% limit. However, the increased fouling during extended GR-SI operation at full load

TABLE 6-1 SUMMARY OF AIR EMISSIONS UNDER GR-SI

Operating Mode	Total Duration (Hours)	Gross Power (MWe)	Gas Heat (%)	Ca/S Molar Ratio	CEMS O2 (%, dry)	Plant O2 (%, wet)	CO (ppm @ 3% O2)	CO2 (% @ 3% O2)	NOx (ppm @ 3% O2)	NOx (lb/MBtu)	SO2 (ppm @ 3% O2)	SO2 (lb/MBtu)	HC (ppm @ 3% O2)	Opacity (%)
GR-SI	557	62	18.2	1.76	6.00	3.02	57	14.5	184	0.246	1343	2.510	1.9	NA

Notes: Testing Period: January 10, 1992 To October 19, 1992

NA: Not Available

increased the boiler exhaust temperature beyond the capabilities of the humidification system. As a result, the stack opacity increased over time. This was usually not a problem since Hennepin Unit 1 operates in cycling service. ESP performance was satisfactory during a 55 hour long-term GR-SI test at reduced load. Operation was limited to 32 hours at full load.

The manual particulate loading measurements, presented in Section 5, showed that emissions were well below the limit of 0.1 lb/10^6Btu (43 mg/MJ). Tests during April and August/September 1992 were conducted at the ESP inlet and outlet ducts while the unit operated under various loads and operating conditions. The emissions averaged 0.021 lb/10^6Btu (9.1 mg/MJ), with an average grain loading of 0.010 gr/dscf (0.022 g/m^3).

The quality of water discharged by the Hennepin Station is regulated by the NPDES permit. A modified permit was issued by the Illinois Environmental Protection Agency (IEPA) on June 2, 1989. It specifies discharge limits and monitoring requirements for the following sources of discharged water:

Stream Number	Discharge Stream
001	Condenser Cooling Water
001 (a)	Boiler Blowdown
001 (b)	Intake Screen Backwash
001 (c)	Roof Drain Discharge
003	Ash Lagoon #2 and #4 Discharge
005	Ash Lagoon #3 Discharge
005(a)	Chemical Metal Cleaning Waste Treatment System Effluent

The GR-SI demonstration project significantly impacts only Stream No. 005, which contains the bottom ash and fly ash transport water from Unit 1. This was estimated to be 0.35 million gallons per day (MGD) (1.32 million liters per day [MLD]), but was expected to increase to 0.69 MGD (2.61 MLD) during-full load GR–SI operation. The permit specifies the frequency and type of sampling required to verify that the following maximum discharge limits are not exceeded:

pH	Minimum: 6	Maximum: 9
Total Suspended Solids (TSS)	Average: 15.0 mg/l	Maximum: 30.0 mg/l
Oil and Grease:	Average: 15.0 mg/l	Maximum: 20.0 mg/l

The permit also specifies limits of thermal impacts on the main river water. A maximum temperature rise of 5°F (3°C) above the natural temperature and maximum temperatures of 60 to 90°F (16 to 32°C), depending on the month, are also specified.

Application of GR–SI to Hennepin Unit 1 was expected to change the nature and quantity of ash produced, but the expected impacts on the sluice water makeup were expected to be minor. The GR–SI ash is fully characterized in the following section. Only a minor impact on the total suspended solids was expected, since the sorbent size (mean particle diameter of 5 microns) is small and the sorbent has a lower settling rate. But with proper retention time in the pond, any increase in total suspended solids was expected to be limited. Injection of CO_2 was used to bring the pH to the acceptable range, and no impact on the oil or grease level was expected. Some increase in sulfates was expected since the spent sorbent sluiced is mostly $CaSO_4$.

The compliance monitoring conducted by IP during long-term GR–SI testing indicated no discharge from the ash pond. The existing pond is unlined, resulting in flow into the ground instead of discharge to the Illinois River. During the first quarter of 1992, eight sluice water samples were taken during baseline operation and five during GR–SI operation. The pH of all samples was in the range of 6 to 9.

Supplemental analyses of ash sluice water were conducted. Samples taken during baseline operation as well as the long-term testing period were analyzed and the results are shown in Table 6-2. The results indicate low metals content, with most metals not detected. Moderate levels of sulfates, Fe, and CaO were detected. The sluice water concentrations are not required to conform to the limits stated above since those apply to water discharged to the Illinois River and no discharge took place during the long-term testing period.

Supplemental monitoring of groundwater was also conducted. The groundwater sampling data for sulfite, sulfate, nitrate as nitrogen, nitrite as nitrogen, total dissolved solids, boron, chloride, etc. are presented in Table 6–3. The groundwater concentration standards depend on the classification. Class I and Class II groundwater have standards for total dissolved solids (TDS) of 1200 mg/l and sulfate of 400 mg/l. Application of GR–SI to the unit potentially increases sulfate concentration in the water discharged, due to sluicing of solid $CaSO_4$. Elevated groundwater concentrations of sulfates, relative to the standards, were measured in some of the wells.

6.1.2 Fly Ash/Spent Sorbent Disposal

The physical and chemical characteristics of the spent sorbent/fly ash were evaluated in the design phase of the project and then later at the initiation of the testing at the Hennepin Station. Changes in ash characteristics were evaluated by firing coal representative of the normal supply for Hennepin in a pilot scale test furnace, under conditions designed to simulate baseline and GR-SI conditions. The ash produced was then evaluated by EER and an outside commercial laboratory. The baseline ash contained approximately 55% silica (SiO_2), 21% alumina (Al_2O_3), 12% ferric oxide (Fe_2O_3), and various other materials and trace minerals. The GR-SI ash composition was 42% Calcium oxide (CaO), 28% silica (SiO_2), 11% alumina (Al_2O_3), 6% ferric oxide (Fe_2O_3), and 6% sulfur trioxide (SO_3) (calcium sulfate). The evaluation indicated that the concentrations of 8 metals tested for in the EP toxicity test were far below

TABLE 6-2. SLUICE WATER ANALYSES
(BASELINE OPERATION)

24 hour Composite Samples From: 8:30 7/20 From: 8:30 7/22

Sampling Period To: 8:30 7/21 To: 8:30 7/23

Parameter	Units	Method	MDL	Result	Method	MDL	Result
Arsenic [As] (tot)	mg/l	SW6010	0.1	ND	SW6010	0.2	ND
Barium [Ba] (tot)	mg/l	SW6010	0.003	0.022	SW6010	0.1	4.2
Cadmium [Cd] (tot)	mg/l	SW6010	0.007	ND	SW6010	0.1	ND
Chromium [Cr] (tot)	mg/l	SW6010	0.025	ND	SW6010	0.2	1.6
Lead [Pb] (tot)	mg/l	SW6010	0.085	ND	SW6010	0.2	ND
Selenium [Se] (tot)	mg/l	SW6010	0.2	ND	SW6010	0.5	ND
Silver [Ag] (tot)	mg/l	SW6010	0.01	ND	SW6010	0.2	ND
Iron [Fe] (tot)	mg/l	SW6010	0.017	0.18	SW6010	0.34	1100
Manganese [Mn](tot)	mg/l	SW6010	0.003	ND	SW6010	0.1	3.2
Mercury [Hg] (tot)	mg/l	SW7470	0.0005	ND	SW7470	0.001	ND
Boron [B] (tot)	mg/l	SW6010	0.25	8.56	SW6010	0.5	ND
Calcium Oxide	mg/l	SW6010	0.3	110	SW6010	0.5	1800
Copper [Cu] (tot)	mg/l	SW6010	0.012	ND	EPA200.7	0.2	0.8
Nickel [Ni] (tot)	mg/l	SW6010	0.034	ND	EPA100.7	0.2	1.25
Zinc [Zn] (tot)	mg/l	SW6010	0.004	ND	EPA200.7	0.2	6.46
Total Dissolved Solids							
(Filt. Residue)	mg/l	EPA160.1	5	620	EPA160.1	5	1100
Total Suspended Solids							
(Non-Filt Residue)	mg/l	EPA160.2	5	5600	EPA160.2	5	20000
Sulfate	mg/l	EPA375.4	5	230	EPA375.4	5	390
Oil and Grease							
(grav)	mg/l	EPA413.1	2	ND	EPA413.1	2	ND
pH (lab)	SU	SW9040	--	9.21	---	---	---

MDL: Method Detection Limit
ND: Not detected at a concentration greater than or equal to the MDL

TABLE 6-2. ASH SLUICE WATER ANALYSES (CONTINUED)
(LONG TERM DEMONSTRATION PERIOD)

Date	1/6/92	1/6/92	1/7/92	1/8/92	1/9/92	1/9/92
Test	----	----	BL	BL	GR	GR
pH	11.08	11.61	11.28	11.15	11.11	11.30
Dissolved Solids (mg/l)	1500	1200	2100	1400	2800	3800
Suspended Solids (mg/l)	5500	10000	5000	4500	2000	1400
Sulfates (mg/l)	480	390	780	500	670	530
Oil, Grease (mg/l)	ND	ND	ND	ND	ND	ND
<u>Metal (mg/kg)</u>						
As	ND	ND	ND	ND	ND	ND
Ba	5.9	3.8	9	5.6	5.4	4.4
Cd	ND	ND	ND	ND	ND	ND
Cr	ND	ND	ND	ND	ND	ND
Pb	ND	ND	ND	ND	ND	ND
Se	ND	ND	ND	ND	ND	ND
Ag	ND	ND	ND	ND	ND	ND
Fe	450	320	780	530	360	330
Mn	5.4	3.6	8.0	4.5	5.0	3.9
Hg	ND	ND	ND	ND	ND	ND
B	50	30	74	50	54	40
CaO	74	53	110	66	1600	1200

TABLE 6-3. GROUNDWATER ANALYSES

Sample Date	Well #	Water Level	pH	Temp °C	SO_3 mg/l	TDS mg/l	B mg/l	SO_4 mg/l	NO_2 mg/l	Cl mg/l	NO_3 mg/l	Ca mg/l	Mn mg/l
2/5/92	W1	446.21	7.3	12.5	<0.5	700	5.1	95	0.02	52.0	<.05	110	130
2/5/92	W2	446.52	8.6	13.5	<0.5	990	14.0	450	0.02	69.2	0.1	160	23
2/5/92	W3	447.98	7.2	13.2	<0.5	600	3.4	480	0.02	36.2	0.1	100	230
2/5/92	W4	446.72	7.8	12.9	<0.5	820	5.0	190	0.02	66.6	<.05	140	98
2/5/92	W5	446.52	7.3	12.1	<0.5	410	1.7	120	0.02	27.8	8.2	89	<5
2/5/92	W5rep	——	——	——	<0.5	410	2.0	90	0.02	27.6	9.0	87	<5
8/25/92	W1	444.73	7.4	14.4	<0.5	730	5.9	260	0.02	51.7	<.05	100	120
8/25/92	W2	445.28	8.8	14.1	<0.5	800	13.0	320	0.02	87.7	<.05	130	1400
8/25/92	W3	445.44	7.4	14.9	<0.5	750	5.0	250	0.02	50.6	0.1	130	120
8/25/92	W4	445.35	7.3	14.4	0.6	870	6.7	350	0.02	61.3	<.05	130	120
8/25/92	W5	444.99	7.4	12.9	<0.5	410	1.5	77	0.02	23.6	8.3	74	<5
8/25/92	W1rep	——	——	——	<0.5	720	5.6	240	0.02	52.2	0.1	100	110
11/17/92	W1	447.97	7.4	12.9	<0.5	738	6.4	280	0.02	53.8	<.05	98	100
11/17/92	W2	448.23	8.9	12.6	<0.5	824	12.5	402	0.02	81.3	0.1	108	17
11/17/92	W3	448.40	7.4	12.5	<0.5	663	4.4	241	0.02	39.8	<.05	87	460
11/17/92	W4	448.36	7.3	12.5	0.6	867	7.5	395	0.02	60.0	<.05	110	63
11/17/92	W5	444.99	7.9	11.1	<0.5	418	1.8	73	0.02	26.1	8.4	77	<5
11/17/92	W3rep	——	——	——	<0.5	696	4.7	239	0.02	43.1	<.05	87	540
2/2/93	W1	449.51	7.1	12.9	<0.5	609	4.6	230	0.02	43.2	<.05	87	140
2/2/93	W2	449.61	7.1	12.1	<0.5	1048	12.2	560	0.02	87.4	<.05	88	26
2/2/93	W3	450.23	7.1	12.1	<0.5	639	4.8	250	0.02	39.5	<.05	170	230
2/2/93	W4	449.99	7.1	12.9	<0.5	868	7.4	400	0.02	60.2	<.05	96	92
2/2/93	W5	449.71	7.0	11.5	<0.5	395	1.6	76	0.02	24.8	8.0	78	<5
2/2/93	W3rep	——	——	——	<0.5	610	5.1	230	0.02	45.3	<.05	89	130
5/18/93	W1	448.23	7.0	14.0	<0.5	720	5.6	270	0.02	52.4	<.05	94	140
5/18/93	W2	448.18	8.6	15.1	<0.5	920	11.4	420	0.02	77.2	1.0	130	25
5/18/93	W3	449.00	7.2	14.2	<0.5	690	4.6	260	0.02	42.0	<.05	91	270

TABLE 6-3. GROUNDWATER ANALYSES (Continued).

Sample Date	Well #	Water Level	pH	Temp °C	SO_3 mg/l	TDS mg/l	B mg/l	SO_4 mg/l	NO_2 mg/l	Cl mg/l	NO_3 mg/l	Ca mg/l	Mn mg/l
5/18/93	W4	448.84	7.2	14.4	<0.5	850	7.7	430	0.02	69.6	<.05	110	120
5/18/93	W5	448.53	7.3	11.6	<0.5	450	1.8	130	0.02	38.0	6.1	81	<5.0
5/18/93	W2rep	——	——	——	<0.5	910	11.6	470	0.02	76.6	1.2	120	27
8/17/93	W1	448.22	7.4	14.2	<0.5	790	5.8	300	0.02	56.6	<.05	92	130
8/17/93	W2	448.27	8.9	13.3	<0.5	920	9.7	490	0.02	70.2	1.0	92	16
8/17/93	W3	448.78	7.3	13.5	<0.5	850	4.9	320	0.02	52.8	<.05	78	870
8/17/93	W4	448.77	7.4	14.2	<0.5	900	7.6	430	0.02	73.0	<.05	94	130
8/17/93	W5	448.47	7.3	11.8	<0.5	610	2.5	240	0.02	56.2	3.8	83	<5.0
8/17/93	W5rep	——	——	——	<0.5	611	2.3	230	0.02	56.4	4.1	94	<5.0
Average		447.73	7.5	13.1	<0.5	717	6.0	286	0.02	53.7	3.7	102	210

hazard levels. Due to the high CaO content the material was found to increase in temperature when hydrated; therefore, care in its handling was recommended. Pozzolanic activity tests indicated that the spent sorbent/fly ash has cementitious properties, hardening to a very strong material.

The project originally called for construction of a new ash pond for disposal of the ash/spent sorbent. This would have required modification of the NPDES permit as well as additional permitting considerations due to construction in a 100-year floodplain. Due to several factors including prohibitive cost of construction of a new ash pond, sluicing of the GR–SI ash to the original pond was decided upon. A modified NPDES was issued by the IEPA addressing the required handling of GR–SI ash and the required environmental monitoring in case of a discharge to the Illinois River. The permit specified use of CO_2, acetic acid or other chemical to reduce the pH to approximately 9.0. Other, less costly methods of pH reduction were prohibited due to their potential to increase chloride and sulfate levels in the Illinois River and groundwater. Since no discharge to the river occurred during the GR–SI demonstration, the extensive monitoring specified was limited. If a discharge had occurred, two types of testing would have been required: chemical specific testing on a quarterly basis, and biomonitoring of acute toxicity. The chemical specific testing was conducted regularly, even though not required by the conditions of the NPDES Permit. Biomonitoring was not conducted.

6.1.3 Potential Environmental Concerns

The environmental monitoring results indicate that GR-SI has no deleterious impacts on the local environment. The applicable standards for air and aqueous discharges were met while operating GR-SI. The solid waste product was non-hazardous and was injected with CO_2 to control the pH level and readily sluiced to the existing ash collection pond.

The only area of concern in applying GR–SI addressed in IEPA's Construction Permit was PM_{10} (particulate matter with an aerodynamic diameter under 10 microns) emissions. The design evaluation predicted that total particulate matter emissions would not increase, due to application of flue gas humidification.

Particulate matter sampling was conducted during baseline, GR, and GR–SI operation. As presented in Section 10, the maximum emissions rate was 0.035 lb/10^6Btu (15.1 mg/MJ), measured under baseline operation. Humidification was successfully applied, resulting in particulate emissions of 0.015 to 0.025 lb/10^6Btu (6.5 to 10.8 mg/MJ) during full-load GR–SI operation. A small increase in the fraction of the PM_{10} was observed for GR–SI emissions. During full-load GR–SI operation the fraction of particulate matter under 10 microns was approximately 75 to 90% of the outlet loading. This may be compared to a baseline PM_{10} loading of approximately 60 to 75% at the ESP outlet. However, since the total mass of particulate emissions are *reduced by a small amount* [GR-SI Full Load Average: 0.021 lb/10^6Btu (9.1 mg/MJ), Baseline Full Load Average: 0.026 lb/10^6Btu (11.1 mg/MJ)], this change in the fraction of PM_{10} did not increase the total emitted.

The temporary reductions in NO_x and SO_2 emissions due to GR-SI operation had the potential for application of NSPS or PSD provisions of the CAAA on completion of the program, when the emissions would rise to original levels. Section 60.14 of Title 40 of the Code of Federal Regulations (40 CFR 60.14) states that "any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification" necessitating permitting of the facility as a new source. In addition, 40 CFR 52.21 indicates that an increase in NO_x or SO_2 emissions of 40 tpy (36 tonne/a) makes a source subject to PSD provisions of the CAAA. But, since the primary purpose of the retrofit was to control gaseous emissions, it was expected that EPA would rule that the retrofit was not a modification triggering new emissions standards.

A modified permit to construct was issued by the IEPA on May 27, 1992. The permit granted construction of a flue gas humidification system, a sorbent silo with fabric filter, a sorbent surge tank with a fabric filter, a multiclone in the FGR line, and the SI system.

6.2 Lakeside GR-SI Demonstration

Environmental monitoring was conducted to evaluate the performance of the GR-SI system, to ensure environmental acceptability of the process, and to compile a database of environmental impacts for future applications. Monitoring of gaseous and aqueous discharges from the site was conducted as directed by the Environmental Monitoring Plan (EMP). The EMP, prepared in Phase I of the project, described potential impacts of GR-SI on the local environment and outlined testing required to evaluate these impacts. Environmental measurements were divided into those required to satisfy operating permits issued by the Illinois Environmental Protection Agency (IEPA) and supplemental measurements. The Lakeside Station is permitted as both an air emissions source and a source of aqueous discharge. The aqueous discharges are regulated by the National Pollutant Discharge Elimination System (NPDES) permit. Compliance monitoring was conducted by plant personnel, who issued monthly reports to IEPA. Supplemental measurements were made in the areas of gaseous emissions, stack particulate loading, and solid waste (fly ash/spent sorbent) characterization.

The major product of GR-SI is a solid material, which is a mixture of spent sorbent and fly ash. Prior to initiation of the project, the fly ash was sluiced to an on-site pond. Due to the change in its chemical composition, from the presence of spent and unreacted sorbent, the dry ash/spent sorbent was conveyed to a newly constructed silo for off-site disposal. The characteristics of the fly ash/spent sorbent mixture were evaluated in Phase I with material produced in EER's test furnace. At the initiation of Phase III GR-SI testing, material from Lakeside Unit 7 was tested to obtain the required waste disposal permit.

6.2.1 Environmental Monitoring Results

This section presents results of environmental monitoring in the areas of gaseous and particulate matter emissions and aqueous discharges. Gaseous emissions were measured continuously during GR, SI, and GR-SI operation from a sampling grid at the boiler exit. The CEMS, described in Section 6, met the requirements of U.S. EPA Methods 3A *"Determination of Oxygen and Carbon Dioxide Concentrations in* Emissions From Stationary Sources," 6C "Determination of Sulfur Dioxide Emissions from Stationary Sources," 7E "Determination of Nitrogen Oxides Emissions from Stationary Sources," and 10 "Determination of Carbon Monoxide Emissions from Stationary Sources." Particulate matter emissions were evaluated primarily with a plant opacity meter, which transmitted data continuously to the BPMS. At the conclusion of the GR-SI demonstration, stack particulate matter emissions were *measured manually according to U.S. EPA Method 5, "Determination of Particulate* Emissions From Stationary Sources." Aqueous discharges were tested regularly by plant personnel, as dictated by the NPDES permit. Two discharge streams were of interest in this project, the ash pond discharge (Outfall 004) and the coal pile runoff (Outfall 008).

Table 6-4 summarizes the gaseous emissions under the three operating conditions over the Phase III demonstration period. From July 28, 1993 to June 3, 1994, GR-only operation was conducted for 288 hours, SI-only operation was conducted for 38 hours, and GR-SI were operated simultaneously for 202 hours. GR was operated with an average gas heat input of 23.1%, SI had an average Ca/S of 1.93, and GR-SI was operated at an average gas heat input of 22.0% and a Ca/S of 1.81. Reductions in SO_2 emissions were calculated from the 5.9 lb/10^6Btu (2500 mg/MJ) baseline and reductions in NO_x were calculated from the correlated baseline, NO_x (lb/10^6Btu) = 0.522 + 0.0134 * gross load (MW_e).

In GR-only operation, NO_x emissions averaged 0.356 lb/10^6Btu (153 mg/MJ). This is a reduction of 60% from the baseline level. SO_2 emissions averaged 4.483 lb/10^6Btu

TABLE 6-4 SUMMARY OF AIR EMISSIONS UNDER GR, SI, AND GR-SI

Operating Mode	Total Duration (Hours)	Gross Power (MWe)	Gas Heat (%)	Ca/S Molar Ratio	CEMS O2 (%, dry)	Plant O2 (%, wet)	CO (ppm @ 3% O2)	CO2 (% @ 3% O2)	NOx (ppm @ 3% O2)	NOx (lb/MBtu)	SO2 (ppm @ 3% O2)	SO2 (lb/MBtu)	HC (ppm @ 3% O2)	Opacity (%)
GR	288	27	23.1	0.00	4.18	3.30	180	14.3	268	0.356	2412	4.483	6.2	4.6
SI	38	26	0.0	1.93	4.88	3.78	14	15.3	657	0.896	1900	3.621	NA	5.7
GR-SI	202	28	22.0	1.81	4.22	2.97	179	14.2	251	0.334	1335	2.486	NA	5.0

Notes: Testing Period: July 28, 1993 To June 3, 1994

NA: Not Available

(1930 mg/MJ), which represents a direct reduction according to the gas heat input. Emissions of CO_2 averaged 14.3%, which is approximately 7% less than the baseline level. CO emissions were on average in the upper end of the acceptable range, at 180 ppm. HC emissions were very low, at 6.2 ppm. After obtaining several HC measurements, testing for this species was discontinued due to difficulty in maintaining the HC analyzer operability. The opacity of the flue gas was on average 4.6%, which is far below the regulatory limit of 30%.

SI-only operation resulted in average SO_2 emissions of 3.621 lb/10^6Btu (1560 mg/MJ). This is a 39% reduction from the baseline level and has an associated calcium utilization of 20%. Emissions of CO were very low in this case, with an average of 14 ppm. Emissions of CO_2 were equal to the baseline level, while NO_x was reduced a small amount due to air staging under this condition. The opacity was maintained very low at 5.7%, even with the increased particulate loading into the ESP.

Under GR-SI the NO_x emissions were reduced to 0.334 lb/10^6Btu (144 mg/MJ), a 63% reduction, and SO_2 emissions were reduced to 2.486 lb/10^6Btu (1070 mg/MJ), a 58% reduction. GR-SI operation followed modification of the reburning fuel injectors to optimize their performance. These modifications resulted in improvement in NO_x reduction over the GR-only case. The SO_2 reduction reflects a 22% reduction due to natural gas switching and a further reduction of 46% due to SI. The sorbent calcium utilization in this case was 25%. Emissions of CO_2 and CO were, as in the GR-only case, a 7% reduction in CO_2 and CO emissions of 179 ppm. Opacity of the flue gas averaged 5.0%, indicating effective capture of particulate matter by the ESP.

The manual particulate loading measurements, presented in Section 7, showed that emissions were well below the limit of 0.1 lb/10^6Btu (43 mg/MJ). Three sampling runs were conducted at the stack while the unit was under full load GR-SI operation. The emissions averaged 0.016 lb/10^6Btu (6.9 mg/MJ), with an average grain loading of 0.0080 gr/dscf (0.018 g/m^3).

Table 6-5 summarizes the measurements of aqueous discharges potentially affected by GR-SI. These compliance measurements were conducted by plant personnel and reported to IEPA on a monthly basis. One of the potential impacts was an increase in pH due either to the possible but unexpected contamination of bottom ash with sorbent or to the spillage of the lime in the area of the coal pile. Outfall 004 - the ash pond discharge - includes water used in sluicing bottom ash to the ash pond. The NPDES limits the pH of this stream to the 6 to 9 range, concentration of Total Suspended Solids (TSS) for a 30 day average to 15.0 mg/l and daily maximum to 30.0 mg/l, and concentration of oil and grease to a 30 day average of 15 mg/l and daily maximum of 20 mg/l. Table 6-5 data show that for only one monitoring period was the daily maximum pH limit exceeded and for only one period were the 30 day average and daily maximum TSS exceeded. During all the other monthly monitoring periods the limits were met. Outfall 008 - the coal pile runoff - has the same limits as Outfall 004 with an additional limit for total iron of 2.0 mg/l, averaged over 30 days, and 4.0 mg/l for the maximum daily. The data show that during the demonstration period there was rarely a discharge from this stream. On one occasion the daily maximum TSS limit was exceeded. The pH levels indicate that spillage of lime, if any, did not change the neutrality of this discharge stream.

6.2.2 Fly Ash/Spent Sorbent Disposal

The physical and chemical characteristics of the spent sorbent/fly ash were evaluated in the design phase of the project and then later at the initiation of testing at the Lakeside Station. Coal from the Lakeside was fired in a test furnace with the sorbent. The fly ash/spent sorbent mixture was then evaluated by EER and a commercial laboratory. The composition was 52% calcium oxide (CaO), 18% silica (SiO_2), 16% sulfur trioxide (SO_3), and 5% alumina (Al_2O_3). The evaluation indicated that concentrations of 8 metals tested for in the EP toxicity test were below hazard levels. The material was found to increase in temperature when hydrated; therefore, care in its handling was recommended. Pozzolanic activity tests indicated that the spent

TABLE 6-5. AQUEOUS DISCHARGE MONITORING DATA

(OUTFALL 004 - ASH POND DISCHARGE)

Measurement	Flow (MGD)			pH			Total Suspended Solids (mg/l)			Oil & Grease (mg/l)			Boron (mg/l)		
Period	Min.	Avg.	Max.	Min.	Avg.	Max.	Min.	Avg.	Max.	Min.	Avg.	Max.	Min.	Avg.	Max.
9/1/93 - 10/1/93	5.19	5.19	5.19	7.4	8.3	8.9	2	9	17	1	1	2	5.2	5.3	5.4
10/1/93 - 11/1/93	0.00	4.61	6.63	8.5	8.7	9.0	5	7	11	1	2	3	3.5	4.1	4.8
11/1/93 - 12/1/93	5.91	5.91	5.91	8.3	8.6	8.8	2	8	18	1	1	1		4.4	5.2
12/1/93 - 1/1/94	0.00	5.23	5.91	7.6	8.3	8.4	3	5	8	2	3	3	6.1	6.2	6.3
1/1/94 - 2/1/94	5.19	5.19	5.19	7.9	8.1	8.5	4	12	26	2	2	2	6.0	6.3	6.5
2/1/94 - 3/1/94	5.19	5.73	5.91	8.1	8.3	8.4	7	11	15	2	3	4	4.6	4.7	4.9
3/1/94 - 4/1/94	5.19	5.91	6.63	8.1	8.3	8.8	8	15	28	1	1	1		5.2	5.8
4/1/94 - 5/1/94	0.00	3.46	5.19	8.0	8.5	9.0	13	24	34	0.2	2	4	1.8	2.0	2.2
5/1/94 - 6/1/94	5.19	5.37	5.91	7.7	8.5	9.3	6	12	19	2	2	2	4.6	4.8	4.9

(OUTFALL 008 - COAL PILE RUNOFF)

Measurement	Flow (MGD)			pH			Total Suspended Solids (mg/l)			Oil & Grease (mg/l)			Total Iron (mg/l)			Dissolved Iron (mg/l)		
Period	Min.	Avg.	Max.	Min.	Avg.	Max.	Min.	Avg.	Max.	Min.	Avg.	Max.	Min.	Avg.	Max.	Min.	Avg.	Max.
10/1/93 - 11/1/93	0.00	0.05	0.72	7.8	7.9	8.1	5	7	9	3	3	4	0.2	0.2	0.2	0.02	0.06	0.09
4/1/94 - 5/1/94	0.00	0.01	0.24			8.1			72			0.36						

Note: No Discharge During Periods Not Shown sorbent/fly ash was probably not suitable as a cement admixture material. A paint filter test indicated that the material did not have a liquid component. Overall, the fly ash/spent sorbent was determined to be non-hazardous, and dry collection and off-site disposal at a landfill was selected.

To obtain the necessary landfill disposal permit, a Toxicity Characteristic Leaching Procedure (TCLP) analysis was carried out with fly ash/spent sorbent from Lakeside Unit 7. A high volume SLM dust sampler was used to collect a sample from the convective pass while the unit was operating SI. The results of the analysis are shown in Table 6-6. A 10% solution was found to be alkaline, with a pH of 12.26. The constituents of raw sample, shown in the "Total" column, and of the TCLP extract were very low in the metals tested. The concentrations of organic compounds in the TCLP were found to be below 50% of the regulatory limit in each case.

6.2.3 Potential Environmental Concerns

The environmental monitoring results indicate that GR-SI has no deleterious impacts on the local environment. The applicable standards for air and aqueous discharges were met while operating GR-SI. The solid waste product was non-hazardous and was readily collected in a silo, then transported off-site for disposal.

The only performance parameter addressed in IEPA's Construction Permit was PM_{10} (particulate matter with an aerodynamic diameter under 10 microns) emissions. It was estimated in the permitting process that PM_{10} emissions could increase by as much as 129 tons/yr (117 tonne/a), requiring review of the project under federal Prevention of Significant Deterioration (PSD) provisions. IEPA ruled in its Construction Permit that the GR-SI demonstration met PSD provisions as outlined in 40 CFR 52.12. It also stated that the use of fabric filters in the sorbent silo, sorbent surge hopper, fly ash silo, and fly ash separator met the requirement for use of Best Available Control Technology (BACT). It required a particulate emissions test to verify that the

TABLE 6-6. EVALUATION OF THE FLY ASH/SPENT SORBENT MIXTURE

Total Alkalinity	30.5% as NH4OH		
Soluble Alkalinity	6.6% NH4OH		
Insoluble Alkalinity	25.3% as Ca(OH)2		
Ash Content	100.00%		
Odor of Sample	None		
Open Cup Flash Point	> 180 F		
Paint Filter	Pass		
Physical Appearance	Grey Ash		
Reactive Sulfide	< 5.0		
Total Cyanide	< 5.0		
Total Phenolics	< 10.0		
Total Solids	100.0%		
Water Reactivity	Dissolved in Water		
pH (10% solution)	12.26 (units)		
	Total		TCLP
Arsenic	19		0.25
Barium	26		——
Cadmium	4		< 0.1
Chromium	32		< 0.1
Copper	25		< 0.1
Lead	34		0.29
Mercury	0.09		——
Nickel	38		0.1
Selenium	10		0.35
Silver	< 2.5		——
Zinc	130		< 0.1

Note: Unless Otherwise Indicated, All Results Expressed as ppm

TABLE 6-6. EVALUATION OF THE FLY ASH/SPENT SORBENT MIXTURE (CONTINUED)
ANALYSIS OF EXTRACT FROM TCLP

Compound	Concentration	Method Detection Limit	Regulatory Limit
1. Benzene	<0.25	0.01	0.50
2. Carbon Tetrachloride	<0.25	0.01	0.50
3. Chlorobenzene	<50	0.01	100.00
4. Chloroform	<3.0	0.01	6.00
5. o-Cresol	<100.0	0.01	200.00
6. m-Cresol	<100.0	0.01	200.00
7. p-Cresol	<100.0	0.01	200.00
Toal Cresol	<100.0	0.01	200.00
8. 1,4-Dichlorobenzene	<3.75	0.01	7.50
9. 1,2-Dichloroethane	<0.25	0.01	0.50
10. 1,1-Dichloroethene	<0.35	0.01	0.70
11. 2,4-Dinitrotoluene	<0.07	0.01	0.13
12. Hexachlorobenzene	<0.07	0.01	0.13
13. Hexachloro-1,3-butadiene	<0.25	0.01	0.50
14. Hexachloroethane	<1.50	0.01	3.00
15. Methyl Ethyl Ketone	<100.0	0.01	200.00
16. Nitrobenzene	<1.00	0.01	2.00
17. Pentachlorophenol	<50.0	0.01	100.00
18. Pyridine	<2.50	0.01	5.00
19. Tetrachloroethylene	<0.35	0.01	0.70
20. Trichloroethylene	<0.25	0.01	0.50
21. 2,4,5-Trichlorophenol	<200.00	0.01	400.00
22. 2,4,6-Trichlorophenol	<1.00	0.01	2.00
23. Vinyl Chloride	<0.10	0.01	0.20

Note: All Results Expressed as ppm

emissions limit of 0.1 lb/10^6Btu (43 mg/MJ) was met. In this test, as described above, the full load average loading was found to be 8.76 lb/hr (1.10 g/s). Using a capacity factor of 25%, this corresponds to a particulate emissions rate of 9.6 tons/yr (8.7 tonne/a), significantly less than the stated PM_{10} limit of 152.3 ton/yr (138.3 tonne/a).

The *Construction Permit also addressed resumption of normal operating mode at the* completion of the demonstration. It stated that resumption of the normal operating mode would not be considered a modification requiring implementation of NSPS, as found in 40 CFR 60, Subparts a and Da. It also specified that resumption of the normal operating mode would not be considered a modification under the federal PSD rules, as outlined in 40 CFR 52.12.

7.0 ECONOMICS

The capital and operating costs for the GR system for NO_x emissions reduction and the SI system for SO_2 emissions reduction are based on a retrofit of a 300 MWe coal cyclone-fired power plant. The degree of complexity regarding retrofit costs were factored based on the retrofit costs for the GR-SI demonstrations completed under this DOE contract. Separate capital and operating costs are presented for the GR and the SI systems. These two systems were treated as separate technologies; the only major synergistic effect of the GR system on the SI system is the reduction of SO_2 based on the replacement of sulfur-containing coal with natural gas devoid of sulfur.

7.1 Gas Reburning System

7.1.1 GR - Economic Parameters

The capital cost estimates presented summarize major equipment cost, approximate bulk material take-offs, and installation labor to arrive at direct construction costs. Construction indirects are added which include: field supervision, construction overhead and fee, and freight. In addition, costs for detailed engineering, project management, procurement, construction management, start-up, and contingency are included to develop the total installed system cost. All engineering and construction costs are representative of a turn-key contract arrangement. EER considers these estimates to be Class II, Preliminary Estimates. The estimates are expected to be representative of the actual cost -10%/+15%. This is based on the information available at this time which includes preliminary process design and conceptual engineering completed, recent major equipment quotes, bulk material takeoff's and average expected labor rates and productivity.

This section provides the basis for the estimating procedures, along with a list of assumptions used for estimating installation manhours and costs. The cost estimates have been developed using the following sources of information for equipment pricing and for the development of labor costs:

- Richardson's Rapid System 1993 edition of Process Plant Construction Estimating Standards
- Questimate Cost Estimating software by Icarus Corp.
- Means Electrical Cost Data 1991 edition
- Vendor Quotations for Major Equipment
- EER's database of previous equipment purchases

Data from all of these sources were summarized using EER cost estimating software. Once the direct costs were determined, costs for field supervision, contractor overhead and fee, freight, engineering, project management, construction management, start-up, and contingency were added to determine the total installed cost.

7.1.2 GR - Estimated Process Capital Cost

The design of the GR system included three integrated systems: 1) natural gas injection, 2) FGR, and 3) OFA injection. Natural gas is mixed with FGR at the gas injection nozzles located above the cyclone barrel re-entrant throats. A natural gas header was assumed to exist at the station and a tie-in was made to this supply header to provide the natural gas for the GR system. The tie-in pipe supplied gas to a control and metering station and from this station natural gas was distributed to gas injection nozzles located above the cyclone barrel re-entrant throats. The natural gas valve train, common to all of the injection nozzles, included flow metering and control equipment, and safety shut-off valves.

An FGR system was also included, hot flue gas was drawn from the economizer flue gas outlet with an FGR fan, routing the flue gas to the natural gas injectors. The purpose of using FGR with natural gas injection is to increase the dispersion and mixing of natural gas throughout the furnace Reburn zone. The use of FGR increases the NOx reduction efficiency of natural gas reburning systems. The FGR system included a multiclone for particulate removal upstream of the FGR fan.

OFA was assumed supplied from the existing hot secondary combustion air windbox. The existing windbox pressure on a cyclone-fired unit is adequate, so booster fans were not required. The installation of natural gas/flue gas injectors and OFA ports requires furnace tubewall modifications. The high windbox pressure of cyclone-fired units, 30" to 75" WC depending on whether the unit is a forced draft or balance draft unit, precludes the necessity of adding booster air blowers for the OFA system.

The total cost of equipment and materials for the GR system was estimated at $1,130,069. The following is a list of equipment/material and costs by area, that make up the total equipment and materials cost for the system.

Equipment/Materials Description	Equipment/Material Cost
Natural Gas Injection Unit:	*$125,488*
NG Supply Piping	
NG Valve Train Piping	
NG Header Piping	
NG Injector Piping	
NG Nozzle Flex Hose	
NG Injection Assembly	
NG Vent Piping	
NG Instrumentation, Valves & Dampers	
NG Tubewall Modifications	
NG Injector Cooling Air Piping	
FGR Unit:	*$548,360*
FGR Fan	

Hot FGR Duct to Inlet of Fan
FGR Duct from Fan to Boiler
FGR Injector Duct Header

OFA Unit: *$374,621*

OFA Main Ductwork
OFA Main Duct Expansion Joints
OFA Branch Ductwork
OFA Branch Duct Expansion Joints
OFA Nozzle Ducts
OFA Nozzle Supports
OFA Injection Nozzles
OFA Instrumentation & Dampers
OFA Tubewall Modifications

Other: *$ 81,600*

Control Modifications
Electrical Work
New Structural Steel

The estimated total capital requirement to retrofit a GR system to an existing 300 MWe cyclone-fired unit is **$5,060,000** or a cost of **$16.85/kWe**. The breakdown of costs is presented in Table 7-1.

7.1.3 GR - Projected Operating and Maintenance Costs

EER conducted analyses to evaluate the fixed and variable (operating) costs of a GR system for a 300 MWe coal cyclone-fired power plant (net heat rate of 10,000 Btu/kWhr before GR); contributing cost factors were as follows:

1. Reburning Fuel Cost Differential Since gas costs more than coal on a heating value basis ($\$/10^6$ Btu), there is a cost related to the amount of gas fired. This was calculated based on the delivered costs of gas and coal, the percentage of gas fired (20.1% of the total heat input). A value of $\$1.00/10^6$ Btu was used

TABLE 7-1. NATURAL GAS REBURNING SYSTEM
300 MWe CYCLONE-FIRED UNIT

Capital Cost

Category	$\$10^6$	\$/kWe
Equipment	1.13	3.77
Construction Labor	0.92	3.07
Construction Indirects	0.78	2.60
Other (6%), Freight (2%) & Taxes (5%)	0.15	0.49
Gas Supply [1]	0.00	0.00
Gas Metering & Reduction Station	0.45	1.50
Total Process Capital	3.43	11.43
Engineering (10% of process capital)	0.34	1.14
Project Management (8%) /Owners Costs (5%)	0.45	1.49
Project Contingency @ 15%	0.63	2.11
Total Plant Cost	4.85	16.17
Allowance for Funds During Construction [2]	0.00	0.00
Total Plant Investment (TPI)	**4.85**	**16.17**
Royalty Fees @ 0.5% of Total Process Capital	0.02	0.06
Startup Costs @ 3% TPI	0.15	0.49
Working Capital @ 0.9% TPI	0.04	0.15
Cost of Construction Downtime (28 days) [3]	0.00	0.00
Total Capital Requirement	**5.06**	**16.85**

[1] Gas supply availability at site assumed adequate
[2] No allowance included based on DOE guideline
[3] Assumed downtime to be during scheduled major outage

as the differential between the delivered price of natural gas ($2.47/10^6 Btu) and the delivered price of coal ($1.47/10^6 Btu).

2. Changes in Boiler Efficiency Since the boiler efficiency is lower when using gas as the reburning fuel there needs to be an increase in the amount of fuel fired to make up for the lower efficiency. This increase was based upon the boiler efficiency loss (1.27%) with GR and a composite fuel cost of $1.67/10^6 Btu.

3. Reduced Load on Coal Crushers Since the GR fuel contributes a significant portion of the boiler fuel, there is a corresponding percentage decreased load on the coal crushers. The electricity credit was based on an auxiliary power cost of $0.02/kWhr.

4. Maintenance Items/Spare Parts An allowance of 2% of the total plant investment was used for total maintenance, 40% of this 2% was allocated for maintenance items and spare parts.

5. Maintenance Labor An allowance of 2% of the total plant investment was used for total maintenance, 60% of this 2% was allocated for maintenance labor.

6. Administration and General Overhead An allowance of 60% of plant labor was added to cover administration and general overhead.

7. Local Property Taxes and Insurance An allowance of 3% of total plant investment was used to cover taxes and insurance.

The total annual incremental gross operating cost for the GR system, exclusive of any payback of capital, is estimated at $4,177,496. If an SO_2 allowance credit is taken based on the reduction of fuel sulfur when firing natural gas, the net operating cost is estimated at $3,422,703. This SO_2 credit was based on an allowance of $95/ton (Feb. 1996). The operating cost breakdown for the GR system retrofit to a 300 MWe cyclone-fired unit is shown in Table 7-2.

7.1.4 GR - Summary of Performance and Economics

Based on the developed capital and fixed/variable operating costs, economic projections were made using current dollars which include an inflation rate of 4.0%, and constant dollars which ignore inflation. The factors used in the development of the technology economics are shown in Table 7-3.

TABLE 7-2. NATURAL GAS REBURNING SYSTEM
300 MWe CYCLONE-FIRED UNIT

Annual Incremental Operating Costs[1]

	Annual Use	Cost/Unit	Cost/ Yr
Variable Costs			
Fuel:			
Natural Gas	3,436,898 10^6 Btu	$1.00 /$10^6$ Btu [2]	$3,436,898
Supplemental Fuel	243,645 10^6 Btu	$1.67 /$10^6$ Btu [3]	$407,131
Utilities:			
Electricity	3,794 10^3 kWhr	$20.00 /$10^3$ kWhr	$75,888
Ash Disposal Credit	(3,389) tons	$9.29 /ton[4]	($31,484)
Sub-Total			$3,888,432
Fixed Costs			
Labor: [5]			
Maintenance (2% of TPI x 60%)			$58,201
Supervision (20% of Maintenance Labor)			$11,640
Supplies:			
Maintenance (2% of TPI x 40%)			$38,801
Admin. and Gen. Ovhd. (60% of total labor)			$34,920
Local Taxes and Insurance @ 3% of TPI			$145,502
Sub-Total			$289,064
Total Gross Operating Cost			**$4,177,496**
SO2 Allowance @ $95/ton [6]			**($754,793)**
Total Net Operating Cost			**$3,422,703**

[1] 65% Capacity factor @ 300 MWe net capacity (10,000 Btu/kWhr heat rate) w/ 20.1% fuel heat input as natural gas
[2] Natural gas assumed delivered at $2.47/MM Btu; coal cost at $1.47/MM Btu
[3] Extra fuel added to make up for loss in efficiency (1.27%) at same coal/gas ratio as reburn
[4] Credit for less fly ash, based on 25% carryover, assuming cyclone bottom slag can be disposed of at no cost
[5] Assumed no added operating labor required to operate the GR system
[6] February 1996 Allowance Credit Value, reduction based on 4.8 lb SO2/MM Btu for coal w/coal reduction of 19.84%

TABLE 7-3. ECONOMIC FACTORS

Item	Units	Value
Cost of debt	%	8.5
Inflation rate	%	4.0
Construction period	mos.	9
Remaining life of power plant	-	15
Year for cost presented in this report	-	1996
Royalty allowance based on total process capital	%	0.5
Capital charge factor - current dollars	-	0.160
Capital charge factor - constant dollars	-	0.124
O&M cost levelization factor - current dollars	-	1.314
O&M cost levelization factor - constant dollars	-	1.000
Power plant size	MWe (net)	300
Power plant type	cyclone	-
Power plant capacity factor	%	65
Sales tax rate	%	5.0
Cost of freight	%	2.0
Engineering/home office fees of total process capital	%	18.0

Table 7-4 shows the performance and cost for a 300 MWe GR System that is retro-fitted to a cyclone-fired boiler. The table reflects the NOx reduction costs based a 65% capacity factor with 20.1% of the heat input supplied by natural gas at a gas to

TABLE 7-4. NATURAL GAS REBURNING SYSTEM PERFORMANCE AND COST FOR 300 MWe CYCLONE-FIRED UNIT

Summary of Data

Power Plant Attributes

	Units	Value
Plant capacity, net	MWe	300
Power produced, net	10^9 kWhr/yr	1.71
Capacity factor	%	65
Plant life	yr	15
Coal feed	tons/yr	683,280
Sulfur in Coal	wt%	3.0

Emissions Control Data

	Units	NOx
Removal efficiency	%	67.0
Emissions standard	lb/10^6 Btu	0.94
Emissions without controls	lb/10^6 Btu	1.30
Emissions with controls	lb/10^6 Btu	0.43
Amount reduced	tons/yr	7,439

Levelized Cost of Power

	Current Dollars		Constant Dollars	
	Factor	Mills/kWhr	Factor	Mills/kWhr
Capital Charge	0.160	0.47	0.124	0.37
Fixed O&M	1.314	0.22	1.000	0.17
Variable Operating Cost	1.314	2.99	1.000	2.28
Total Cost		3.69		2.81
SO_2 Credits	1.314	(0.58)	1.000	(0.44)
Total Cost w/SO_2 Credits		3.11		2.37

Levelized Cost - NOx Removal Basis

	Factor	$/ton removed	Factor	$/ton removed
Capital Charge	0.160	109	0.124	84
Fixed O&M	1.314	51	1.000	39
Variable Operating Cost	1.314	687	1.000	523
Total Cost		***847***		***646***
SO_2 Credits	1.314	(133)	1.000	(101)
Total Cost w/SO_2 Credits		***713***		***544***

Basis: 67% NOx reduction assumed based on larger unit with longer Reburn zone residence time than CWLP 33 MWe cyclone unit (58% NOx reduction w/20% gas heat input as Reburn fuel).

coal price differential of \$1.00/million Btu. The incremental increase in the levelized cost of power, including capital charges is estimated at 2.81 mills/kWhr in constant dollars and 3.69 mills/kWhr in current dollars. If an SO_2 credit is applied based on fuel sulfur reduction when firing natural gas, the net incremental increase in the levelized cost of power is estimated at 2.37 mills/kWhr in constant dollars and 3.11 mills/kWhr in current dollars. The levelized cost of NO_x removal is estimated at \$646/ton and \$847/ton for constant and current dollar projections, respectively. If an SO_2 credit is applied based on fuel sulfur reduction, the net levelized cost of NO_x removal is estimated at \$544/ton and \$713/ton for constant and current dollar projections, respectively. Based on the levelized cost (in constant dollars) for reducing nitrogen oxides, excluding SO_2 credits, the capital charge component made up only 13% of the total cost of NO_x reduction. The fixed operation and maintenance costs represented only 6%, and the variable cost made up the rest of the cost for removing NO_x. The cost of NO_x removal shows that the variable operating cost is the greatest cost component, making up some 81% of the NOx reduction. Further, the most significant component of the variable operating cost is the cost of natural gas.

7.1.5 GR - Effect of Variables on Economics

The cost of NO_x reduction was analyzed and certain variables were then selected to perform sensitivity analyses. The variables chosen were natural gas price, the capacity factor and the unit size, the effects of these variables are shown Table 7-5 and Figures 7-1,7-2, and 7-3.

For the sensitivity analysis, only the variable being analyzed was changed from the base case, all other variables were kept the same. The cost of natural gas is clearly the driving force for the economics of the GR System. A \$0.50 swing in the price of natural gas has the effect of changing the cost of NO_x reduction by over \$200/ton. The effect of capacity factor has a relatively small effect on the cost of NO_x removal. A 10% swing in capacity factor results in a \$17 to \$25/ton variation in the cost for reducing NO_x emissions.

TABLE 7-5. COST OF NO_x REMOVAL

Natural Gas Price, $/10⁶ Btu*	$0.50	**$1.00**	$1.50			
NOx Reduction Cost, $/ton**	$310	**$544**	$779			
Capacity Factor	50%	55%	60%	**65%**	70%	75%
NOx Reduction Cost, $/ton**	$584	$569	$555	**$544**	$535	$527
Unit Size, MWe	100	**300**	450	600	750	900
NOx Reduction Cost, $/ton**	$652	**$544**	$521	$507	$497	$490

Note: Base case variables in bold

* Differential price compared to coal

** Constant dollar basis, includes $95/ton SO_2 credit

To examine the power plant size effect on NOx reduction costs, the capital cost of the 300 MWe unit was used as a base. A scale up factor of 0.75 was used to extrapolate the capital cost for smaller and larger units. This factor was based on a combination of 50% of the equipment being increased in size using a 0.6 scaleup factor and 50% of the equipment being duplicated using a 0.9 scale up factor. The size effect for units larger than 300 MWe has only a slight effect on the cost of NO_x reduction. For a 900 MWe unit the cost of NO_x reduction is only $17/ton less than that for the 300 MWe unit. With smaller units the effect is more dramatic, for a 100 MWe unit the cost of NOx reduction would be $108/ton more than that for the 300 MWe unit.

7.2 Sorbent Injection (SI) System

The SI system was designed to store, meter, and convey micronized hydrated lime (sorbent) to the injection nozzles in the upper furnace of the 300 MWe cyclone-fired Unit. The SI system is comprised of the following major components: sorbent storage silo, weigh hopper, rotary valve feeder, screw pump, air transport blower, conveying line, sorbent splitter, SI air fan, and furnace injection nozzles.

7.2.1 SI - Economic Parameters

See Paragraph 7.1.1.

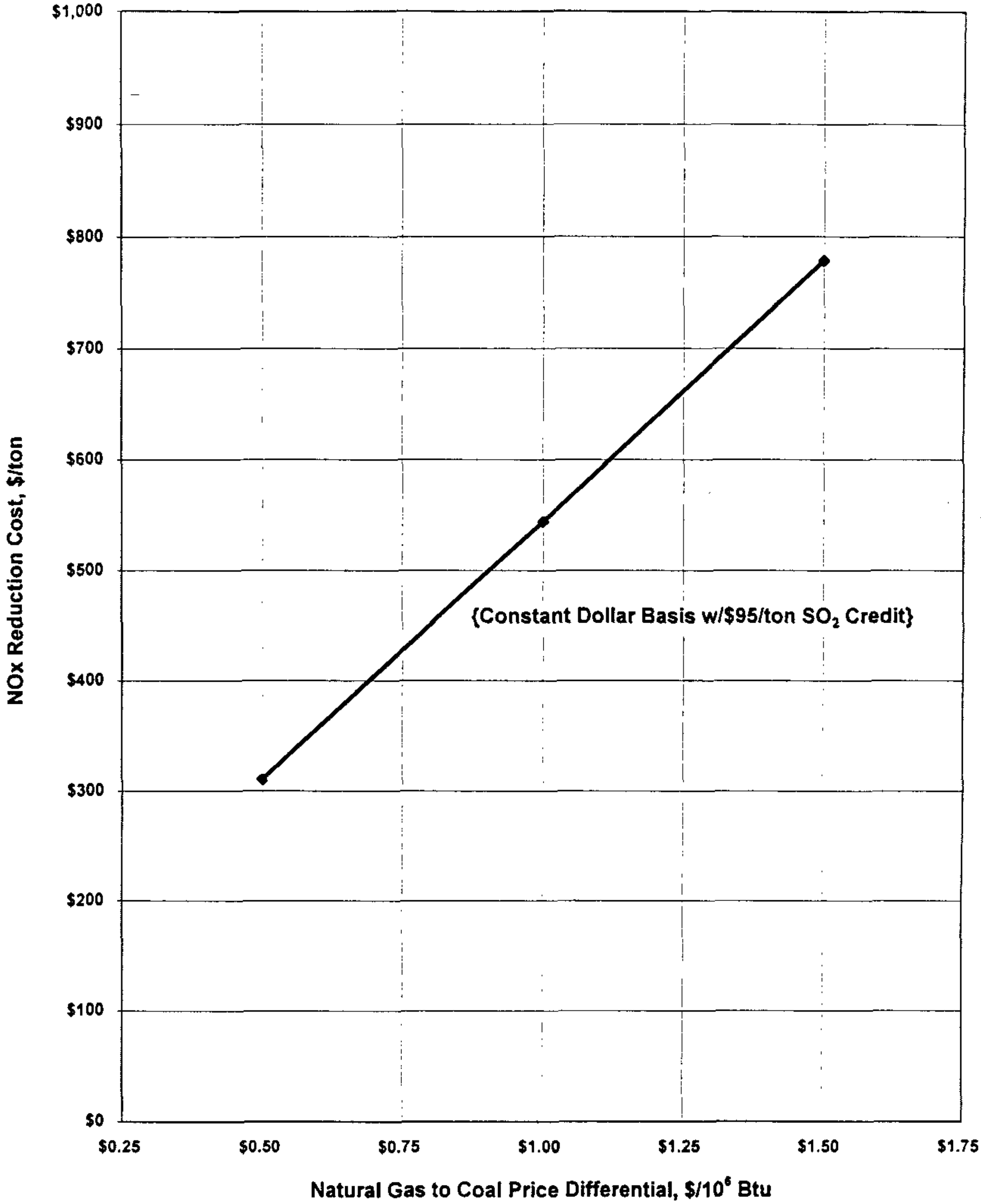


Figure 7-1. Effect of natural gas on NOx reduction cost

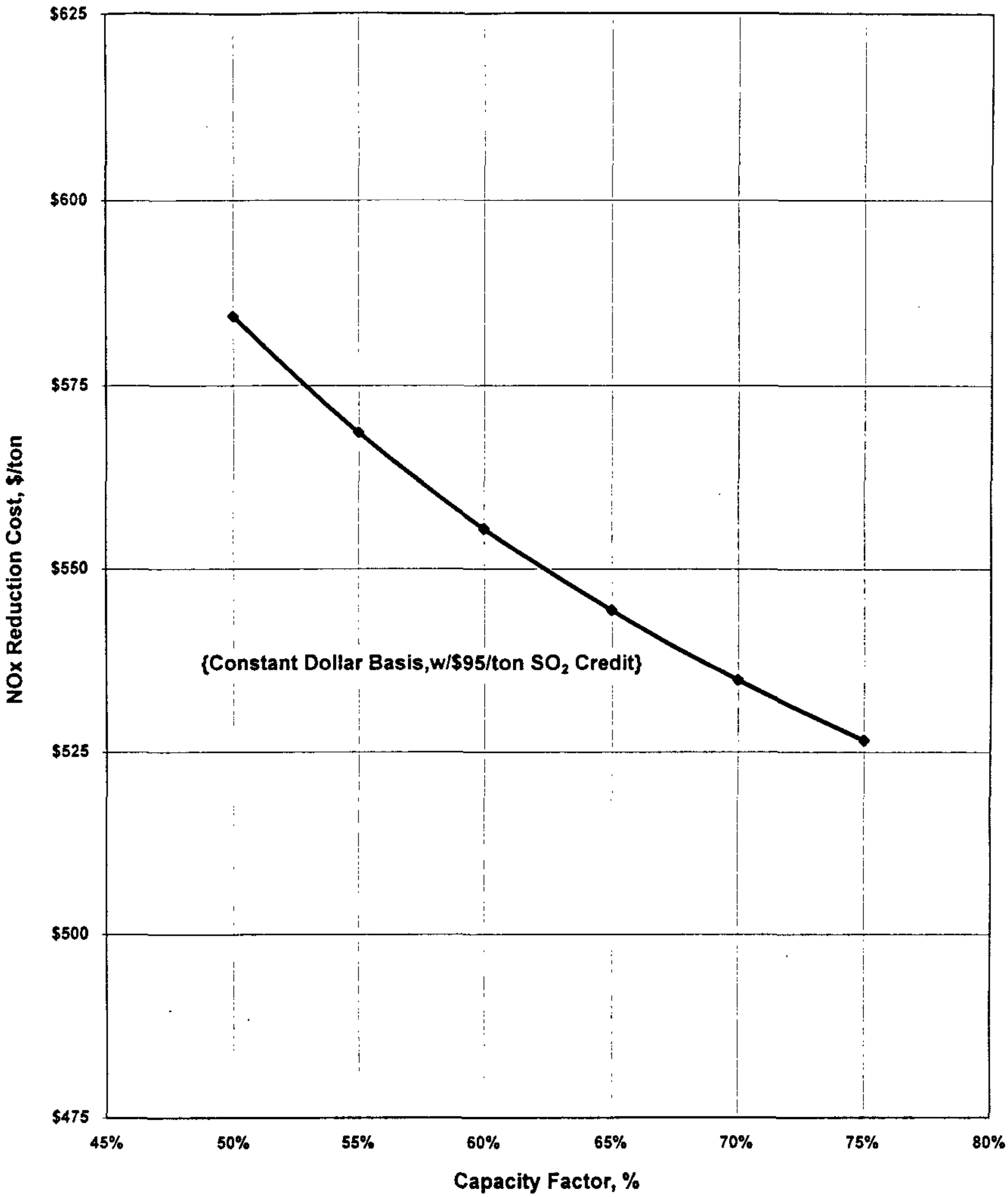


Figure 7-2. Effect of capacity factor on NOx reduction cost

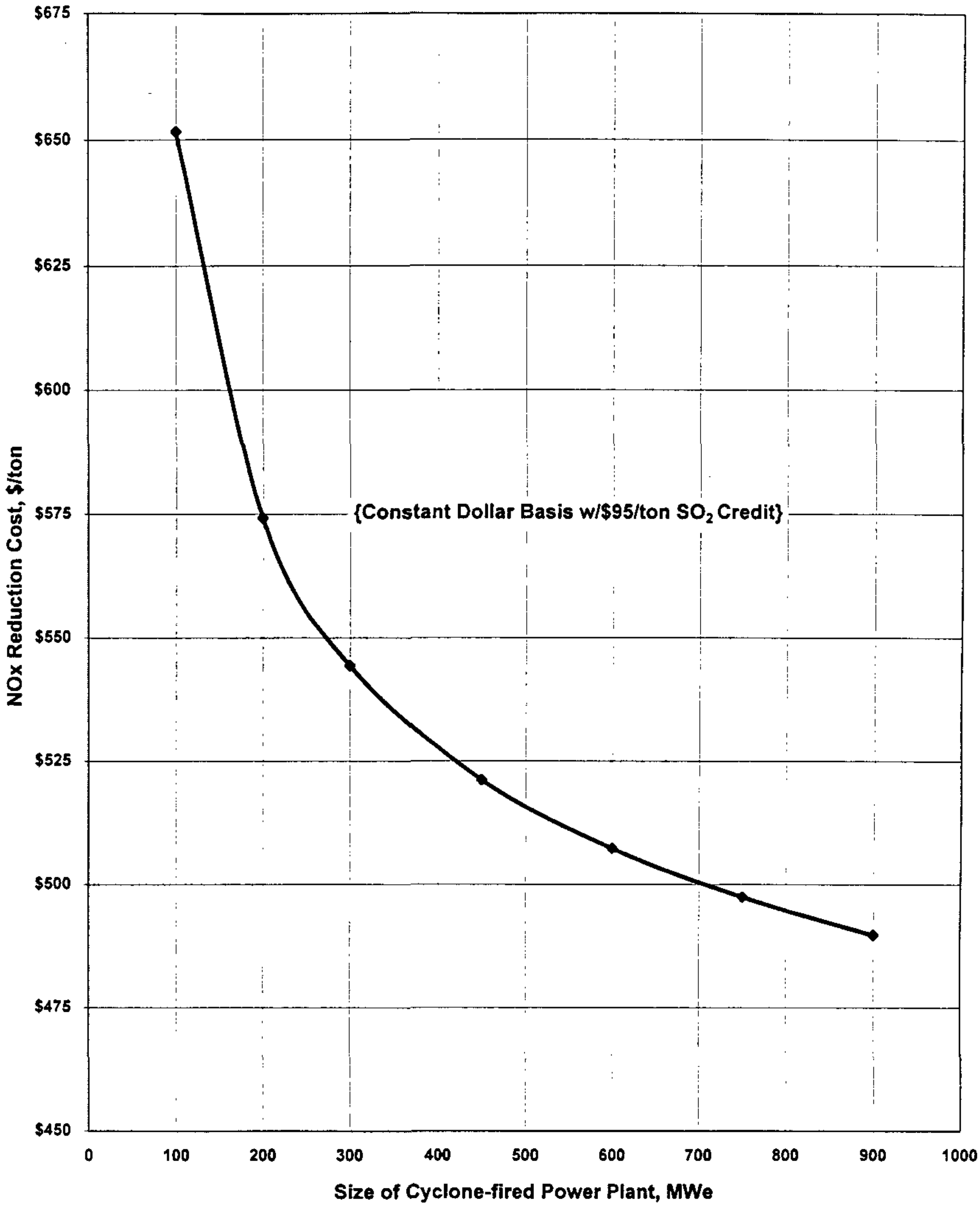


Figure 7-3. Unit size effect on NOx reduction cost

7.2.2 SI - Estimated Process Capital Cost

The total cost of equipment and materials for the SI system was estimated at $883,278. The following is a list of equipment/material and costs by area, that make up the total equipment and materials cost for the system.

Equipment/Materials Description	Equipment/Material Cost
Sorbent Storage Unit:	*$134,710*
Sorbent silo	
Weigh hopper	
Silo vent filter	
Sorbent Feeding Unit:	*$232,774*
Rotary valves	
Sorbent screw pumps	
Sorbent transport blowers	
Dust control unit	
Sorbent Transport:	*$361,686*
Piping, hoses, valves, splitters	
Sorbent equipment air compressors	
Air dryer	
Valves and controls	
Sorbent Injection Unit:	*$154,108*
Coaxial jet sorbent injectors, C.S./S.S.	
SI air fan	
SI nozzle cooling fan	
Instruments/controls	

The estimated total capital requirement to retrofit an SI system to an existing 300 MWe cyclone-fired unit is **$3,860,000** or a cost of **$12.86/kWe**. A breakdown of the capital cost is presented in Table 7-6.

TABLE 7-6. SORBENT INJECTION SYSTEM
300 MWe CYCLONE-FIRED UNIT

Capital Cost

Category	$\$10^6$	\$/kWe
Equipment	0.88	2.94
Construction Labor	0.72	2.40
Construction Indirects	0.61	2.03
Other (6%), Freight (2%) & Taxes (5%)	0.11	0.38
Total Process Capital	2.33	7.75
Engineering (10% of process capital)	0.23	0.78
Project Management (8%) /Owners Costs (5%)	0.30	1.01
Project Contingency @ 15%	0.43	1.43
Total Plant Cost	3.29	10.97
Allowance for Funds During Construction [1]	0.00	0.00
Total Plant Investment (TPI)	**3.29**	**10.97**
Royalty Fees @ 0.5% of Total Process Capital	0.01	0.04
Startup Costs @ 3% TPI	0.10	0.33
Working Capital @ 0.9% TPI & 14 days supply $Ca(OH)_2$	0.46	1.52
Cost of Construction Downtime (21 days) [2]	0.00	0.00
Total Capital Requirement	**3.86**	**12.86**

[1] No allowance included based on DOE guideline

[2] Assumed downtime to be during scheduled major outage

7.2.3 SI - Projected Operating Maintenance Cost

EER conducted analyses to evaluate the fixed and variable operating costs of an SI system for a 300 MWe coal cyclone-fired power plant; contributing cost factors were as follows:

1. Cost of Hydrated Lime Sorbent The purchasing price for hydrated lime was based on the costs incurred for the CCT demonstrations, $83/ton.

2. Sootblowing The frequency of sootblowing was increased for a power plant with an SI system.

3. Ash Disposal An increase of ash disposal results from the addition of sorbent to the boiler furnace.

4. Auxiliary Power The power increases due to the added air blower and air compressor horsepower requirement

5. Maintenance Items/Spare Parts An allowance of 3% of the total plant investment was used for total maintenance, 40% of this 3% was allocated for maintenance items and spare parts.

6. Maintenance Labor An allowance of 3% of the total plant investment was used for total maintenance, 60% of this 3% was allocated for maintenance labor.

7. Administration and General Overhead An allowance of 60% of plant labor was added to cover administration and general overhead.

8. Local Property Taxes and Insurance An allowance of 3% of total plant investment was used to cover taxes and insurance.

The total annual incremental gross operating cost for the SI system, exclusive of any payback of capital, is estimated at $8,610,679. The operating cost breakdown for the SI system retrofit for a 300 MWe cyclone-fired unit is presented in Table 7-7.

7.2.4 SI - Summary of Performance and Economics

Based on the developed capital and operating costs, economic projections were made using current dollars, which include an inflation rate of 4.0%, and constant dollars which ignore inflation. Table 7-8 shows the performance and cost for an SI System

TABLE 7-7. SORBENT INJECTION SYSTEM
300 MWe CYCLONE-FIRED UNIT

Annual Incremental Operating Costs[1]

	Annual Use	Cost/Unit	Cost/ Yr
Variable Costs			
Raw Material:			
Hydrated Lime [2]	87,327 tons	\$83.00 /ton	\$7,248,101
Utilities:			
Electricity	10,480 10^3 kWhr	\$20.00 /10^3 kWhr	\$209,597
Ash Disposal	97,759 tons	\$9.29 /ton	\$908,180
Sub-Total			\$8,365,878
Fixed Costs			
Labor: [3]			
Maintenance (3% of TPI x 60%)			\$59,226
Supervision (20% of Maintenance Labor)			\$11,845
Supplies:			
Maintenance (3% of TPI x 40%)			\$39,484
Admin. and Gen. Ovhd. (60% of total labor)			\$35,536
Local Taxes and Insurance @ 3% of TPI			\$98,710
Sub-Total			\$244,801
Total Operating Cost			**\$8,610,679**

[1] 65% Capacity factor @ 300 MWe net capacity (10,000 Btu/kWhr heat rate)
[2] 95% $Ca(OH)_2$ with Ca/S ratio of 1.75
[3] No incremental operating labor

TABLE 7-8. SORBENT INJECTION SYSTEM PERFORMANCE AND COST FOR 300 MWe CYCLONE-FIRED UNIT

Summary of Data

Power Plant Attributes

	Units	Value
Plant capacity, net	MWe	300
Power produced, net	10^9 kWhr/yr	1.71
Capacity factor	%	65
Plant life	yr	15
Coal feed	tons/yr	683,280
Sulfur in coal	wt%	3.0

Emissions Control Data

	Units	SO_2
Removal efficiency	%	45
Emissions standard	lb/10^6 Btu	1.20
Emissions without controls	lb/10^6 Btu	4.80
Emissions with SI control	lb/10^6 Btu	2.64
Amount reduced	tons/yr	18,654

Levelized Cost of Power

	Current Dollars		Constant Dollars	
	Factor	Mills/kWhr	Factor	Mills/kWhr
Capital Charge	0.160	0.36	0.124	0.28
Fixed O&M	1.314	0.19	1.000	0.14
Variable Operating Cost	1.314	6.44	1.000	4.90
Total Cost		***6.98***		***5.32***

Levelized Cost - SO_2 Removal Basis

	Factor	$/ton removed	Factor	$/ton removed
Capital Charge	0.160	33	0.124	26
Fixed O&M	1.314	20	1.000	15
Variable Operating Cost	1.314	589	1.000	448
Total Cost		***643***		***490***

that is retro-fitted to a 300 MWe cyclone-fired boiler. The incremental increase in the levelized cost of power is estimated at 5.32 mills/kWhr in constant dollars and 6.98 mills/kWhr in current dollars. The levelized cost of SO_2 removal is estimated at $490/ton and $643/ton for constant and current dollar projections, respectively.

7.2.5 SI - Effect of Variables on Economics

The cost of SO_2 reduction was analyzed and certain variables were then selected to perform sensitivity analyses. Based on the levelized cost (constant dollars) for reducing sulfur dioxide emissions, the capital charge component made up only 5.3% of the total cost. The fixed operation and maintenance costs represented only 3.1%, and the variable cost (91.6%) made up the rest of the cost for removing SO_2. The hydrated lime accounted for some 89% of the variable costs. The variables chosen were the cost of hydrated lime, the capacity factor, the unit size and the percentage of sorbent utilization. For the sensitivity analysis, only the variable being analyzed was changed with all other variables being kept the same. The hydrated lime and how well it is utilized is the driving force for the economics of the SI System. The effect of the variables analyzed, on the cost of SO_2 removal, is shown in Table 7-9.

TABLE 7-9. COST OF SO_2 REMOVAL*

Hydrated Lime, $/ton	63	73	**83**	93	103	
SO_2 Removal Cost, $/ton	395	442	**490**	537	584	
Capacity Factor,%	50	55	60	**65**	70	75
SO_2 Removal Cost, $/ton	501	497	493	**490**	487	485
Unit Size, MWe	100	**300**	500	700	900	
SO_2 Removal Cost, $/ton	530	**490**	480	476	473	
Sorbent Utilization,%	**26**	36	46			
SO_2 Removal Cost, $/ton	**490**	354	277			

Note: Base case variables in bold
* Constant Dollar Basis

The effect of hydrated lime purchase price on SO_2 removal cost is shown above in Figure 7-4. A \$20/ton swing in the price of hydrated lime has the effect of changing the cost of SO_2 removal by some \$95/ton. The effect of capacity factor has a relatively small effect on the cost of SO_2 removal, as can be seen in Figure 7-5. A 10% swing in capacity factor results in a \$5-7/ton variation in the cost of SO_2 removal. The capital cost of the 300 MWe unit was used as a base and a scale up factor of 0.7 was used to extrapolate the capital cost for larger units. This factor was based on a combination of some 70% of the equipment being increased in size using a 0.6 scaleup factor and some 30% of the equipment being duplicated using a 0.9 scale up factor. The unit size has a moderate effect on the cost of SO_2 removal, fee Figure 7-6. For a 900 MWe unit, the cost of SO_2 removal is only some \$17/ton less than that for the 300 MWe unit. For smaller units the effect is greater; for a 100 MWe unit the cost of SO_2 removal would be some \$40/ton greater than that for a 300 MWe unit. This is an economy of scale effect with the slope of the curve starting to taper off around the 300 MWe size.

The sorbent utilization, as like the sorbent cost, dramatically impacts the cost of SO_2 removal because it affects the consumption rate of sorbent. For this economic analysis a Ca/S ratio of 1.75 was used with an overall calcium utilization of 26%. As shown in Figure 7-7, an increase in sorbent utilization from 26% to 46% would result in a drop of SO_2 removal cost from \$490/ton to \$277/ton.

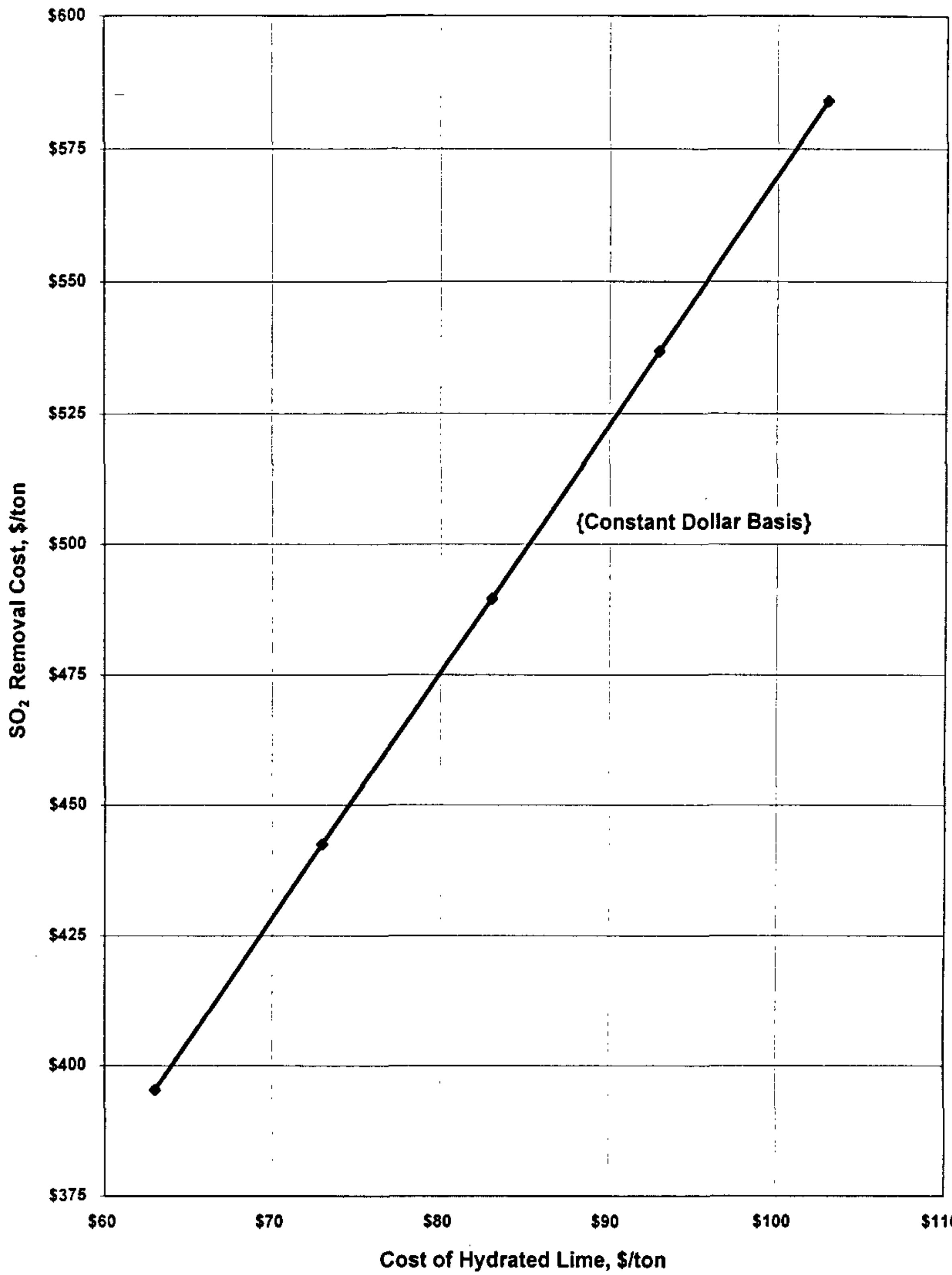


Figure 7-4. Effect of hydrated lime cost on SO_2 removal cost

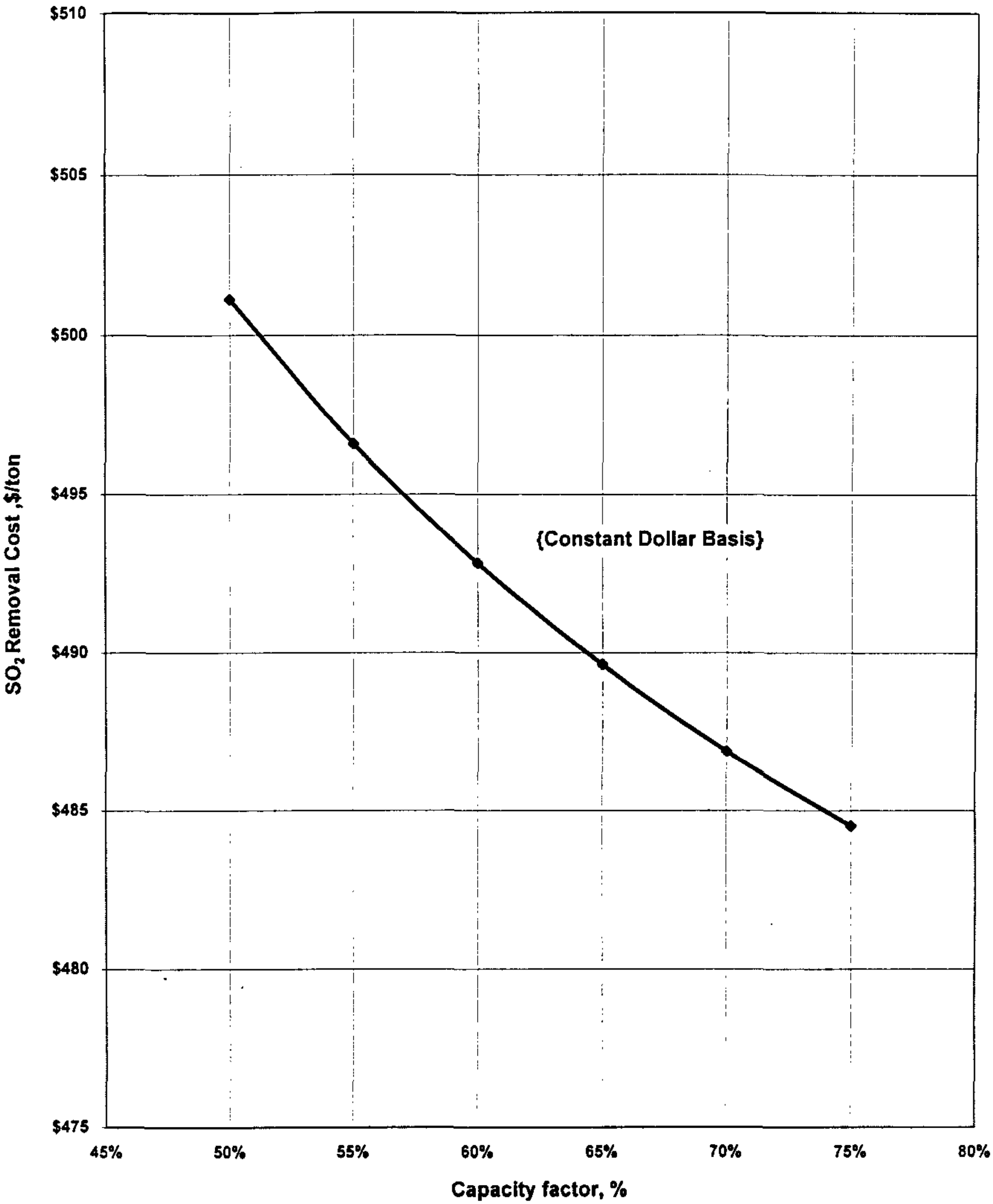


Figure 7-5. Effect of capacity factor on SO_2 removal cost

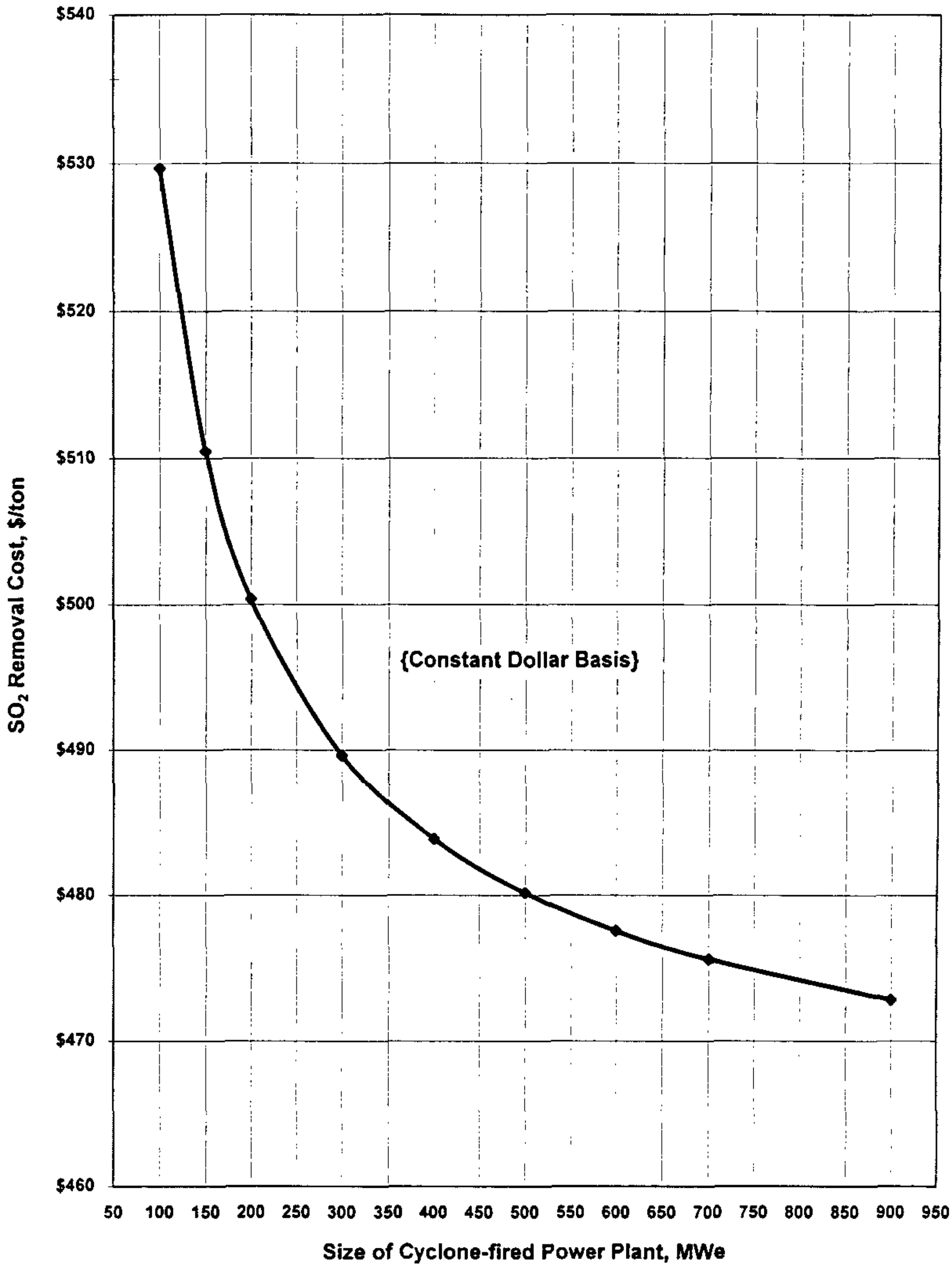


Figure 7-6. Unit size effect on SO_2 removal cost

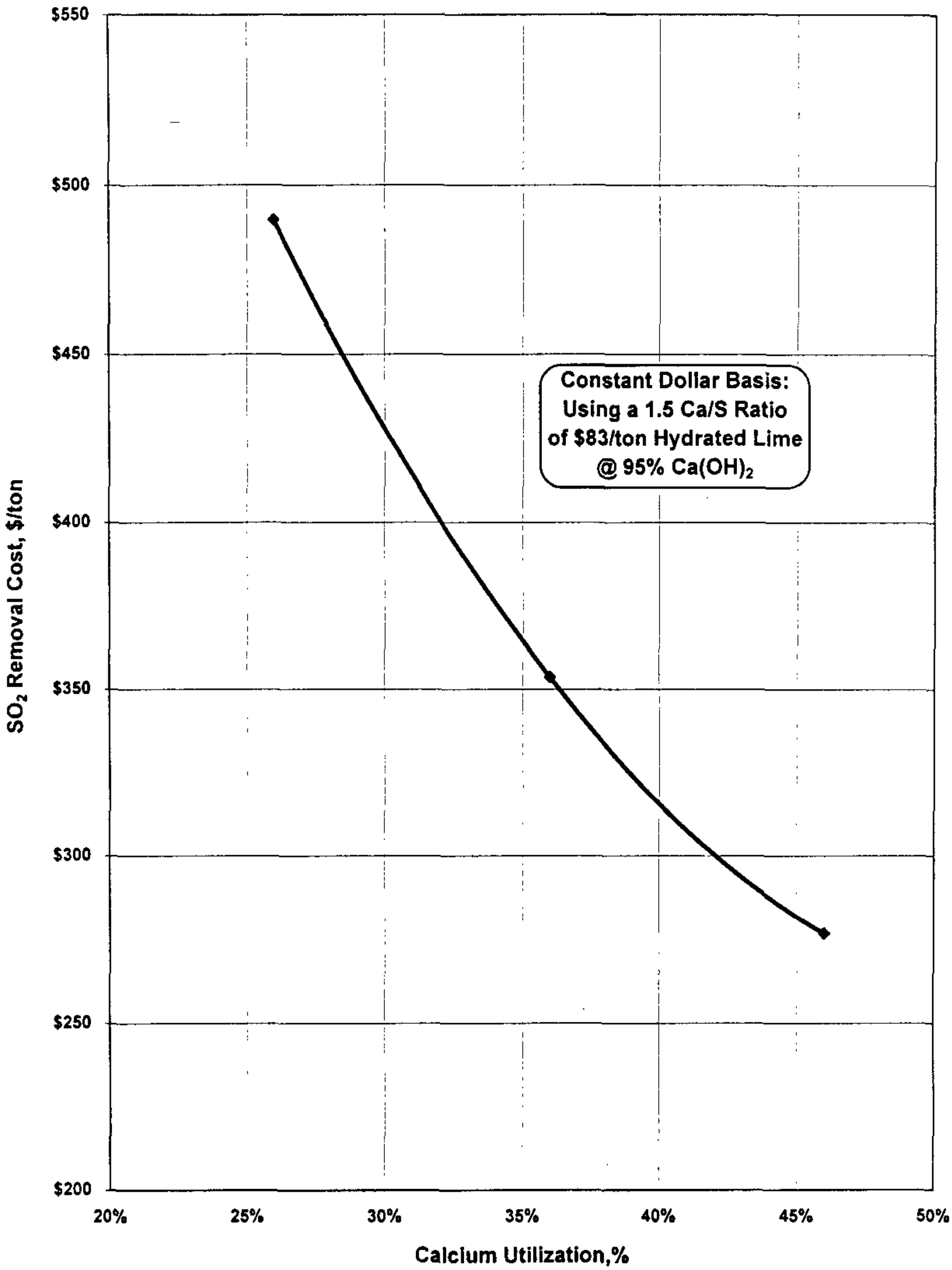


Figure 7-7. Effect of calcium utilization on SO_2 removal cost

8.0 COMMERCIALIZATION POTENTIAL AND PLANS

In the past ten years, the U.S. has seen a very minimal increase in electric power generating capacity. Further, the new power plants that have been built have been of relatively low capacity. This past trend is predicted for the foreseeable future, so GR and SI technologies, when applied, can be retrofitted to existing power plants.

8.1 GR Technology

Title IV of the 1990 Clean Air Act Amendments (CAAA) as specified in §407(b)(2) provides for the reduction of NO_x emissions from coal fired utility boilers. Under the CAAA, boilers were placed in two groups. For the Phase I Group 1 boilers (dry bottom wall-fired and tangentially-fired boilers), regulations were published in the Federal Register on April 13, 1995.

On December 18, 1995, the U.S. Environmental Protection Agency (EPA) proposed its regulations for Phase II Group 1 utility boilers and proposed new regulations for Phase II Group 2 utility boilers. Group 2 comprises the rest of the boiler types used by the utility industry (cyclone-fired, cell burner-fired, wet bottom, dry bottom vertically-fired, stoker-fired, and fluidized bed combustors). With the proposed regulations, the NO_x emission limits for Phase II, Group 1 and Group 2 boilers have been set. The NO_x reductions proposed are providing the impetus to the electric utility industry to more seriously consider GR as a NO_x control strategy. The new proposed utility boiler regulations for NO_x emission limits are shown in Table 8-1.

8.1.1 Market Analysis

The market potential for the GR technology is difficult to assess at the present time in light of the possibility of the Northeast Ozone Transport Region (OTR) being extended from the current 13 states to a total of 37 states. With such an expansion

TABLE 8-1. U.S. EPA PROPOSED NO_x EMISSION REGULATIONS for UTILITY BOILERS

(Annual Average Basis)

Utility Boiler Type	PHASE I Current Regulations April 13, 1995	PHASE II Proposed Regulations January 1, 2000
Group 1:	lb $NO_x/10^6$ Btu	lb $NO_x/10^6$ Btu
Wall-Fired (Dry Bottom)	0.50	0.45
Tangentially-Fired	0.45	0.38
Group 2:		
Cell Burner-Fired	-	0.68
Cyclone-Fired	-	0.94
Wet Bottom	-	0.86
Vertically-Fired	-	0.80
Fluidized Bed	-	0.29

Note: No regulations were proposed for stoker-fired units which in aggregate emit only 3000 TPY of NO_x, less than 0.2 percent of the NO_x emissions of the Group 2 boilers. Cyclone units of less than 80 MWe may be exempt from Phase II regulation.

utility plants in this part of the U.S. If such an expansion does occur, the market for reburning technology will be quite large.

The power plants in all 37 states would then have to meet a NO_x emission level of 0.2 lb NO_x/million Btu or 55/65% reduction of baseline NO_x emissions, with possible future revised regulations that limit emissions to 0.15 lb NO_x/million Btu or a 75% reduction from baseline NO_x emissions. In both cases the least stringent level would have to be achieved. Currently, not many power stations within the added 24 states could meet most of the Midwest will be included and there is an abundance of coal fired electric these levels of reduction. If the OTR is not expanded, the market will be moderate.

The market outside of the OTR will then be driven by the newly proposed US EPA regulations.

Under the proposed U.S. EPA regulations for Phase II Group 1 boilers (dry bottom wall-fired and tangentially-fired boilers), there are low cost retrofit technologies available that can be applied to meet the NO_x emission limits. Both of these boiler types can be brought into compliance with burner (low NO_x) retrofits, or burner retrofits with OFA.

In Group 2, cell burner-fired (36%), wet bottom (13%), and cyclone-fired (41%) boilers make up some 90% of the generating capacity of the group. There are low cost burner replacement options for two-nozzle cell burner-fired boilers and staged combustion appears to be a low cost option for wet bottom boilers to meet the proposed NO_x regulations. However, based on the proposed US EPA limits, a new market is specifically opening for use of reburning technology on cyclone-fired units. The reason for this is that there are not many cost effective NO_x reduction options available for these type of boilers. The U.S. EPA regulation proposed for cyclone-fired units is 0.94 lb $NO_x/10^6$ Btu, and there are some 75 cyclone-fired units (~20,000 MWe) in the United States that are currently exceeding the proposed NO_x emission limit. In addition to cyclone units, power plants in the existing OTR are potentially good market targets. Note that there are no technologies for three-nozzle cell burner-fired boilers.

8.1.1.1 Applicability of the Technology

GR technology can be applied to any type of utility boiler. A gas injector retrofit requires very little space; this is especially true with the new gas injection system developed by EER which does not require the recirculation of flue gas through the gas injector nozzles. Any type of fuel gas can be used for the GR system, natural gas, propane, landfill gas, etc. With GR, an OFA system will also be required. In most cases, the air pressure in the specific boiler windbox would be sufficient for the OFA system, so additional air booster fans would not be required.

8.1.1.2 Market Size for the Technology

The potential size of the market for GR technology will be directly dependent on environmental regulatory agencies; the more stringent the NO_x emission limits, the greater the market size. There are two initiatives now which are operative that will set the size of the market: the OTR and the proposed U.S. EPA NO_x regulations for Phase II Group 1 and Group 2 boilers.

Currently there are thirteen states in the Northeast that are included in the OTR. They have a cooperative agreement under the Northeastern States Cooperative Air Usage Management (NESCAUM) group to reduce NO_x emissions. The member states are Connecticut, Delaware, District of Columbia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia.

In these thirteen states there are 463 boilers, that in 1990 emitted some 1 million tons of NO_x to the atmosphere. The average NO_x emissions rate for these boilers was 0.649 lb/10^6 Btu in 1990. In 1999 these boilers will have to meet a five month control average of 0.2 lb/10^6 Btu, and in the year 2003 will have to meet 0.15 lb/10^6 Btu.

There are also discussions with 24 more states regarding their joining the Northeastern states to lower their NO_x emissions to that agreed under the NESCAUM agreement. If this occurs, the market for reburning will be dramatically increased.

Also, based on the proposed U.S. EPA limits, a new market is specifically opening for the use of reburning technology on cyclone-fired units. The reason for this market is that there are not many cost effective NO_x reduction options available for cyclone-fired boilers. The U.S. EPA regulation proposed for cyclone-fired units is 0.94 lb $NO_x/10^6$ Btu, and there are some 75 cyclone-fired units ($\sim$20,000 MWe) in the United States that are currently exceeding the proposed NO_x emission limit. In addition to cyclone units, power plants in the existing OTR are good marketing targets.

8.1.1.3 Market Barriers

In the case of the GR technology, one critical capital cost item concerns the availability of natural gas. If natural gas is available at the site to supply a sufficient volume, the capital cost would be much less than that compared to a plant that did not have gas on-site. The capital cost differential between the sites would be related to the pipeline distance required to bring gas to the power plant. Another factor that affects the capital cost is the existing combustion air windbox pressure. If there is adequate windbox pressure (4-6 in. W.C. or greater) then a booster OFA fan would not be required. The air pressure required is also dependent on the size of the unit; the larger the size, the higher the air pressure required for optimum penetration with the OFA.

GR is most effective where furnace temperatures are hot (2600+ °F) and residence times in the reburning (reducing) zones are long enough to effectively reduce NO_x emissions. The hotter the reburning zone and the longer the residence time, the greater the NO_x reduction will be for the same rate of gas fired as a reburning fuel. The biggest economic factor that will determine whether or not GR is selected as a means for reducing NO_x emissions at a specific power plant is the cost differential between the reburning fuel (natural gas) and the primary fuel (coal). The smaller the cost differential, the more attractive the GR system will become.

8.1.1.4 Economic Comparison with Competing Technologies

In a study completed for the U.S. EPA (Contract No. 68-D2-0168) "Investigation of Performance and Cost of NO_x Controls as Applied to Group 2 Boilers", NO_x control technologies were investigated. The costs for various NO_x reduction systems applied to cyclone-fired units were developed as part of this study. In Table 8-2, the cost of Coal Reburning, Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR), based on \$/kWe and \$/ton of NO_x removed are shown for 300 MWe cyclone-fired units. They are compared to the costs developed on a similar basis by EER for the GR system.

TABLE 8-2. NO_x CONTROL TECHNOLOGY COMPARISON

Technology	Capital Cost - \$Millions	\$/ton NO_x Removed
Gas Reburning*	9.49	451
Coal Reburning	17.4	520
SNCR**	2.70	700
SCR***	12.9	590

* Natural Gas @ \$2.47/10^6 Btu and Coal @ \$1.47/10^6 Btu

** 50% Urea solution @ \$0.50/gal

*** Anhydrous Ammonia @ \$162/ton & SCR catalyst replacement (3 yr life) @ \$350/ft^3

As shown in the table, the cyclone-fired boiler NO_x control technologies show a cost per ton of NO_x removed that ranges from approximately \$450 to \$700. Based on a comparison with Coal Reburning, SNCR and SCR, GR is the low cost technology when the price differential between natural gas and primary coal is \$1.00 /10^6 Btu.

8.1.2 Commercialization Plans

EER is taking the lead in the commercialization of the GR technology. Much of the marketing efforts of the Corporation is targeted to Reburning technology. EER has presented numerous papers on the NO_x reduction results achieved with the GR technology under the CCT demonstrations. It has developed brochures and has presented seminars to prospective utilities which are solely dedicated to the commercialization of Reburning technology.

EER recently installed and successfully started up a GR system on a glass furnace (Anchor) and is currently starting up a GR system that it installed on a 108 MWe tangentially-fired unit (New York State Electric & Gas). Several other proposals are outstanding for installation of GR on other electric utility boilers. In addition, EER is completing the design of a micronized coal reburning system to be installed on a 50 MWe cyclone-fired unit (Kodak) in the fall of 1996.

In December, 1995, EER formed a strategic alliance with Roll-Royce International Combustion to offer advanced low NO_x control technologies in the United States and throughout the rest of the world. Rolls Royce is one of the world's leading power systems companies; the industrial power group providing equipment for not only power generation, but also electrical transmission and distribution.

The impetus provided by the newly proposed U.S. EPA regulations for Group 2 utility boilers has been the key to EER's successful commercialization of the technology. Clearly, the commercialization of all of the NO_x reduction technologies will be driven by environmental regulations.

8.2 SI Technology

The CAAA of 1990 set a sulfur dioxide emissions reduction schedule that was to be implemented in two phases. In Phase 1 (by 1995) a reduction in SO_2 emissions of some 40% was required for 265 power plants, with the new emission level being set an average rate of emissions of 2.5 lb/10^6 Btu. In Phase 2 (the Year 2000), all sources affected by the CAAA must meet sulfur dioxide emissions levels of 1.2 lb/10^6 Btu. In addition, there is a cap on SO_2 emissions of 8.9 million tons, or some 10 million tons less than was emitted to the atmosphere in 1980.

The CAAA in setting the emissions level has thereby dictated the technologies that can be used to meet these limits. The stringent SO_2 emission limits for the Year 2000 will require high efficiency removal (70 - 85%) for high sulfur coal-fired power plants. Unfortunately, the SI technology achieves only moderate removal of sulfur dioxide (35 to 50% removal). At the time (pre-1990) that the CCT-1 project was awarded to EER by the U.S. DOE, the SI technology was of interest to the electric utility industry. However, with the CAAA of 1990, the attractiveness of the SI technology has diminished.

8.2.1 Market Analysis

The market for the SI technology, because of the CAAA of 1990, will be relegated to those electric utility power plants that just are marginally exceeding their SO_2 emission limits in the Year 2000. Even so, in this case the technology would have to compete with the purchase of SO_2 allowance credits, which in February 1996 was very low, $95/ton.

Although there is not a much of a market in the United States for the technology, a market could open up in growing developing countries (China, India, etc.) whose environmental regulations for air emissions are not as strict as the U.S.

8.2.1.1 Applicability of the Technology

Like the GR technology, the SI technology can also be applied to any type of utility boiler. The technology is best suited for boilers with wide tube spacings and those that have easy retrofit for the additional sootblowers required with an SI system.

8.2.1.2 Market Size for the Technology

Currently, because of the low to moderate capture level capability, there is not a discernible market for the SI technology in the United States. The more reactive and the higher the calcium utilization, the more attractive the technology will become; however, with the availability for purchase of low cost SO_2 allowance credits in combination with electric utilities switching to low cost Western low sulfur coal, a market for the SI technology has not developed.

8.2.1.3 Market Barriers

The biggest market barrier to the SI technology are the stringent SO_2 regulations that will be imposed on the electric utility industry in the Year 2000. The SI technology cannot of itself meet the new SO_2 emission limits of 1.2 lb/10^6 Btu when burning a high sulfur coal. Testing at a reasonable Ca/S ratios (1.35) showed only a 35% reduction in SO_2 emissions when firing high sulfur coal. Even with the GR-SI system where 15-20% of the coal was replaced with natural gas, the reduction level was only some 50-55%. To meet the new emission standards, some 75 to 85% reduction will be required for units firing high sulfur coal. Whereas the technology works, the level of reduction is not at the level required under the new emission limits of the CAAA.

Another market barrier is the SO_2 allowance program. Currently SO_2 allowance credits may be purchased for $75/ton which is less than the cost of removing sulfur with the SI system, estimated at some $475/ton.

There are several operational concerns that an electric utility would have when applying the SI technology. The most significant of these is the fouling of secondary and reheater surfaces. An increase in sootblowing of some 80 to 90% will be required during full load SI operation if one is to maintain a relatively constant boiler exit gas temperature, constant heat loss efficiency, and reduced superheater attemperation water rates. An additional operational problem when using the SI technology is that the concentration of SO_3^- in the flue gas, a normally occurring fly ash conditioning agent, is removed by the sorbent. The reduction of $SO_3^=$ results in an increase in fly ash resistivity that may require a larger ESP collection area, or the addition of flue gas humidification (improved ESP performance) to meet particulate emission limits.

8.2.1.4 Economic Comparison with Competing Technologies

The SI technology is cost competitive with Flue Gas Desulfurization (FGD) processes, based on the costs projected costs for FGD plants, EPRI Report No. GS-7193, "Economic Evaluation of Flue Gas Desulfurization Systems", Volume 1, February 1991. The cost per ton of SO_2 removed for FGD systems is projected at approximately $470/ton. This is based on a 300 MWe power plant, firing 2.6% sulfur coal, and operating at a capacity factor of 65%. This compares to a cost of $476/ton of SO_2 removed based on the SI technology for a 300 MWe power plant fired with 3 wt% sulfur coal that also operates at a plant capacity factor of 65% (see Section 7.1.2).

Although the SI technology looks economically competitive, the problem here is the SO_2 reduction level that is required under new regulations. With the CAAA of 1990, an SO_2 removal technology must achieve 75% or greater reduction to meet the SO_2 emission limit of 1.2 lb $SO_2/10^6$ Btu for power plants firing high sulfur coal ($\geq$3 wt% S). The current SI technology is not capable of achieving these levels of reduction.

8.2.2 Commercialization Plans

Whereas the GR technology is in demand by U. S. electric utilities, under the current environmental regulatory environment, the same is not the case for the SI technology. EER's marketing philosophy is centered on client interest. In the United States, currently there is little interest by the electric utility industry in SI; however, there have been some queries received by EER from certain electric utilities in China and India. EER has provided these interested parties with information on the SI technology, but to-date there have been no projects that have come about as a result of these queries.

9.0 CONCLUSIONS AND RECOMMENDATIONS

9.1 Hennepin GR-SI Demonstration

GR-SI has been demonstrated to be suitable for application to tangentially-fired boilers for reduction of NO_x emissions by 60% and SO_2 emissions by 50%. These reductions, which were the project target levels, were consistently met and exceeded over the year long demonstration. The process also resulted in reductions in CO_2 and CO emissions. Emissions of HCl and HF measured during short-term tests were also significantly reduced. Flue gas humidification has been demonstrated to be suitable for enhancing ESP performance, resulting in particulate matter emissions at or below baseline levels even with the considerable increase in particulate matter entering the ESP. GR–SI had reductions in thermal efficiency of less than 1.5% and an increase in heat rate of less than 200 Btu/kWh (211 kJ/kWh). The main steam temperature was unaffected by GR-SI; however, a small reduction in reheat steam temperature was measured. No significant impacts on the local environment or unit operation and wear rate were detected.

Reductions of NO_x emissions by 67.3% and SO_2 emissions by 52.6% from baseline levels were obtained with a natural gas heat input of 18% and a sorbent input corresponding to a calcium/sulfur molar ratio of 1.75. Under these conditions, NO_x emissions of 0.245 lb/10^6Btu (106 mg/MJ) and SO_2 emissions of 2.51 lb/10^6Btu (1,080 mg/MJ) were obtained over the year–long demonstration period. Under optimum conditions (reduced load with the top mill out of service), NO_x emissions were reduced to 0.179 lb/10^6Btu (77 mg/MJ). SO_2 emissions as low as 2.01 lb/10^6Btu (864 mg/MJ) were measured under optimum GR-SI operation.

NO_x reductions were 55% at 10% gas heat input and increased to 67% at 18% gas heat input. Reductions leveled off in the 12 to 20% gas heat input range. The parameters which appear to most strongly control NO_x emissions are the gas heat input, the coal and reburning zone stoichiometric ratios, the coal burner tilt angle, and the mills in service. Reductions in NO_x emissions were obtained by operation at low primary and reburning zone stoichiometric ratios. During full load GR-SI operation, the coal burner tilt angle also appeared to impact NO_x emissions with lower NO_x emissions measured when the burners were tilted downward. This is due to improved zone separation of the primary combustion and reburning processes. Significant reductions in NO_x emissions were measured when the top mill was out of service, while operating at reduced load.

The parameter which most strongly impacted SO_2 emissions was the sorbent input, or the corresponding Ca/S molar ratio. The calcium utilizations obtained with the primary sorbent evaluated, Linwood hydrated lime, varied significantly and averaged 24.1% over the long-term demonstration. Advanced sorbents, prepared by EER and the Illinois State Geological Survey (ISGS), were evaluated and showed effects due to load and GR. Improved calcium utilizations were obtained at reduced loads and while operating SI, without GR. At a Ca/S molar ratio of 1.75, the performance of three advanced sorbents and the conventional Linwood sorbent may be summarized as follows:

	PromiSORB™ B	HSAHL	PromiSORB™ A	Linwood
SO_2 Capture (%)	66	60	54	46
Calcium Utilization (%)	38	34	31	26

These results were obtained at loads of 40 to 50 MW_e; operation at higher loads resulted in reduced calcium utilizations for advanced sorbents.

Operation of GR–SI had relatively minor impacts on thermal efficiency and steam conditions. These included a reduction in thermal efficiency from the baseline of 86.76% to 85.38% at full load and from 86.54% to 85.09% at 45 MW_e and these resulted in an increase in heat rate of 45 to 173 Btu/kWh (47 to 183 kJ/kWh), or 0.4 to 1.7% of the 10,338 Btu/kWh (10,908 kJ/kWh) baseline.

Main steam temperature was unaffected by GR-SI, with an average of 995°F (535°C) at full load compared to 993°F (534°C) under baseline operation. These may be compared to the design steam temperature of 1,005°F (541°C). During full-load GR-SI operation, the secondary superheater steam attemperation rate increased from a baseline of 6,700 lb/hr (0.84 kg/s) to 12,200 lb/hr (1.54 kg/s). A modest increase in the boiler exit gas temperature, due to fouling of superheater and reheater surfaces, was noted. The air heater exit gas temperature increased from 317°F (158°C) to 350°F (177°C) during full load GR-SI. These effects do not significantly impact the emissions control process, steam generation capacity, or availability of the unit.

Flue gas humidification was successfully applied to enhance ESP performance during GR-SI operation. Cooling of flue gas to the design approach to saturation of 70°F (39°C) was not required, with satisfactory stack opacity and particulate emissions measured at a 150°F (83°C) approach to saturation. The actual humidification water requirement was 25 to 35 gpm (1.6 to 2.2 l/s), which may be compared to the design requirement of 60 gpm (3.8 l/s). With flue gas humidification, particulate matter emissions of 0.015 to 0.025 lb/10^6Btu (6.5 to 10.8 mg/MJ) were measured under full-load GR-SI operation. These may be compared to full load baseline emissions of 0.018 to 0.035 lb/10^6Btu (7.7 to 15.1 mg/MJ). Continuous long-term operation exceeding 55 hours was possible under variable loads, and continuous full-load operation of 32 hours was also achieved with stack opacity within the 30% limit.

Other impacts of the year-long GR-SI demonstration were not significant. Some ash buildup was observed in the cold reheater and primary superheater sections. Increased fouling, especially of the secondary superheater and reheater surfaces, resulted in increased use of sootblowers. However, this did not result in acceleration in tubewall wastage in these areas. The U.T. tubewall thickness data indicates that, in most areas, the wastage rate due to GR-SI was either reduced with respect to the baseline rate, or was within the tolerance for the measurement. Visual inspections of the unit and chimney indicated no significant added wastage due to GR-SI, but some increase in accumulated ash on the inner lining of the chimney.

The successful commercial demonstration of GR–SI at Hennepin Station Unit 1 indicates that the technology is suitable for widespread commercial application to meet the requirements of the CAAA. The results of this project indicate that significant efforts should be directed to marketing these technologies. Further demonstration of GR-SI, or GR at other units over a range of boiler sizes is recommended to assist utilities selecting these technology. The CAAA require that pre-NSPS tangentially fired units limit their NO_x emissions to 0.45 lb/10^6Btu (194 mg/MJ). The Hennepin GR-SI system has been shown to effectively control NO_x emissions to 0.245 lb/10^6Btu (105 mg/MJ). This is well under the CAAA Title IV limit of 0.45 lb/10^6Btu (194 mg/MJ) and is in the range required for Title I.

9.2 Lakeside GR-SI Demonstration

A demonstration of GR-SI at Lakeside Station Unit 7 exceeded the target emissions reductions of 60% for NO_x and 50% for SO_2. Over the long-term GR-SI demonstration period, NO_x reduction averaged 63% and the SO_2 reduction averaged 58%. These were achieved with an average natural gas heat input of 22% and average Ca/S molar ratio of 1.8.

Several GR process parameters were found to have significant impacts on NO_x control efficiency. These include the stoichiometric ratios of the coal (cyclone), reburning, and exit zone, the quantity of FGR used, and the size of reburning fuel injection nozzles. Also, NO_x control varied with operating load. At full load stoichiometric ratios of 1.15, 0.92, and 1.30 for coal, reburning and exit zones, respectively, the project achieved the NO_x control goal. FGR was found to improve NO_x reduction at all loads, with a flow of 6,000 scfm (2.83 Nm^3/s) determined to be optimum. Two sizes of reburning fuel injectors were tested, with the smaller size resulting in improved performance. NO_x control increased at reduced loads due to more uniform reducing conditions in the reburning zone, since the primary flue gas flow is reduced as load drops.

SI in combination with GR exceeded the SO_2 control goal at sorbent inputs below design. Several parameters affected SO_2 capture by sorbent including, most importantly, the Ca/S molar ratio, the SI air flow, the operating load, and whether the GR system was also in operation. The impacts due to load and GR operation are tied to shifts in gas temperature, with higher temperatures resulting in improved sorbent-SO_2 reaction. Therefore, as load dropped below full load, higher levels of Ca/S were required to maintain equivalent SO_2 reductions. During the GR-SI demonstration full load Ca/S molar ratios of 1.5 to 1.9 were used, while at reduced loads Ca/S molar ratios of 1.9 to 2.2 were needed. The SI air flow had a minor impact due to its effect on sorbent dispersion, with maximum flow of 4600 scfm (2.17 Nm^3/s) determined to be optimum.

Emissions of other species were affected by GR-SI. CO_2 emissions were reduced by approximately 8% due to differences in the hydrogen/carbon ratios of the fuels. Emissions of CO increased under GR, requiring use of higher exit stoichiometric ratios to maintain reasonable CO levels. Over the long-term GR-SI demonstration, CO emissions averaged 185 ppm. Emissions of particulate matter were far below the 0.1 $lb/10^6Btu$ (43 mg/MJ) regulatory limit. Stack sampling indicated an average emissions rate of 0.016 $lb/10^6Btu$ (6.9 mg/MJ) during full load GR-SI operation.

There were definite but relatively small impacts on unit thermal performance. Final steam temperature was maintained at approximately 10 to 20°F (5.6 to 11.1°C) below the design point of 910°F (488°C) with a drum attemperator mounted in the upper steam drum. The impacts of GR-SI on boiler thermal efficiency, calculated by the heat loss method, varied with load. At full load the drop in efficiency was approximately 1%, while at mid load (25 MW_e) it was 2% and at low load (20 MW_e) the efficiency was reduced by approximately 3%. GR-SI resulted in shifts in heat absorption, with a minor reduction in furnace heat absorption and an increase in the convective pass heat absorption. Virtually continuous sootblowing was required during SI to maintain heat transfer to the superheaters and to limit the rise in boiler exit temperature.

The impacts of GR-SI on other areas of boiler performance were minor. No change in cyclone and lower furnace conditions was noted. Injection of reburning fuel was found to promote slag buildup around the injectors up to the bottom of the furnace wing walls. Some deposition of loose ash was also noted in the OFA ducts. Further downstream, some deposition of sorbent was found in the flue gas duct common to Units #7 and #8 and in the clean air duct near the air heater, which likely was transferred there by leakage at the regenerative air heater. Inspections of the ESP revealed higher levels of dust on the collecting plates, indicating a need for adjustments/repair of the plate rapping system and change in rapping frequency.

Ultrasonic thickness measurements obtained before initiation of GR-SI and again at the conclusion of testing indicated no acceleration of tubewall wastage. Measurements were taken at 3200 points throughout the lower and upper furnace and in the convective pass. Tubewall samples extracted both before and after GR-SI testing were submitted for metallurgical study. No unusual wear of the tubewall exterior or preferential grain-boundary attack were evident; however, somewhat higher levels of iron sulfide were measured in samples taken from the reburning zone after GR-SI testing.

Overall, the GR and SI technologies were applied successfully, without adverse impacts to the unit or the local environment. Commercial application of the technology is required for further acceptance of GR alone, or GR-SI.

APPENDIX A

HENNEPIN & LAKESIDE GR-SI OPERATING PROCEDURES

1.0 HENNEPIN GR-SI OPERATING PROCEDURES

1.1 GR Pre-Operational Checklist

A. The natural gas manual shut-off valve shall be closed. This is a 6" Rockwell iron plug valve, located at the inlet to the natural gas valve train.

B. Assure that all four (4) natural gas nozzle manual valves are closed.

C. Assure GR nozzle cooling fan is on, and outlet damper is open.

D. Assure that cooling water is flowing to both bearings on the FGR injection fan.

E. Assure FGR isolation damper upstream of multiclone is closed.

F. Assure FGR injection fan inlet damper is closed.

G. Assure FGR injection fan outlet damper is closed.

H. Assure FGR balance dampers are at operating position.

I. Assure that secondary air auxiliary dampers are at GR-SI position.

J. Assure that OFA air dampers are at minimum position.

K. Assure that boiler firing rate is at a minimum of 36 Megawatts.

L. Assure that at least 2 pulverizers are in service.

M. Assure that excess air is at normal excess O_2.

N. Assure that the furnace temperature readings from the optical pyrometers are at least 2400°F.

O. Put GR nozzle tilt controls on automatic (later deleted).

P. Assure that pulverizer coal flow is on automatic.

1.2 GR-Post Operational Checklist

A. The following natural gas valves should be closed:

- Main natural gas manual shutoff
- Natural gas nozzle manual shutoffs (4 valves)

B. The WDPF should indicate that the following dampers are closed:

Multiclone inlet damper

FGR fan outlet damper

OFA damper (West)

(Note: damper should be at minimum for cooling air)

OFA damper (East)

(Note: damper should be at minimum for cooling air)

C. The seal air fan damper should be open.

D. Assure that FGR injection fan turning gear is operating.

E. Assure that water is flowing to the FGR injection fan bearings.

1.3 GR-Permissives, Alarms & Trips

1.3.1 Permissives to initiate GR

GR cannot be initiated if the following conditions exist:

A. FGR Injection Fan Inboard Bearing Temperature High

B. FGR Injection Fan Outboard Bearing Temperature High

C. FGR Injection Fan Inboard Bearing Vibration High

D. FGR Injection Fan Outboard Bearing Vibration High

E. FGR Injection Fan not in automatic

F. FGR Injection Fan Turning Gear engaged

G. Natural Gas Shut-off valve open

H. Natural Gas Pressure High

I. Natural Gas Pressure Low

J. Gas Flow Control valve above minimum

K. Unit Load (MWe) below minimum

L. Furnace Temperature below minimum

M. Flame scanners do not acknowledge Coal Fire

1.3.2 GR Alarms

A. FGR Injection fan discharge damper not closed

B. FGR Injection fan turning gear motor not running

C. Seal air fan not running

D. GR nozzle cooling fan not running

1.3.3 GR and OFA Trips

A. Unit #1 Master Fuel Trip

B. Emergency Stop Initiated by Operator

C. A tripped F.D. fan Unit 1A

D. A tripped F.D. fan Unit 1B

E. OFA System not ready indication

F. GR Permissives not satisfied.

1.4 <u>SI Pre-Operational Checklist</u>

The following items should be verified by a physical walkdown of the system before any start-up can begin. This section does not discuss maintenance items that require attention.

A. The sorbent equipment air compressor must be on and up to pressure. This is a local start/stop at the sorbent silo.

B. Shut-off and bypass valves located by air dryer should be selected to divert the compressed air through the air dryer or to bypass the dryer when not required. These valves are manual and are located at the sorbent silo.

C. The fabric filter should be energized and the bag cleaning process should be audible from the sorbent silo.

D. The fabric filter exhaust fan attached to the top of the filter should be turned on and the damper adjusted so as to maintain a slight vacuum in the hopper that is located beneath the filter. The flexible coupling will be sucked in if a vacuum exists.

E. The weigh hopper discharge valve should be open. This is a manual valve that will remain open unless maintenance work on the rotary valve is required.

F. The valves located beneath sorbent screw pump low seal air pressure solenoid and sorbent transport air pressure transmitter must be open.

G. The manual valve located before the seal air filter must be open. This line supplies seal air to the rotary valve.

H. The sorbent transport hose from the sorbent screw pump to the injection nozzles should be walked down to ensure that no damage has occurred and that all hoses are connected tightly.

I. The ball valves located on discharge of the sorbent flow splitters must be open.

J. The SI air manual balancing valves should be at their preset and marked operating position.

1.5 SI Post-Operational Checklist

The following tasks should be completed after the system has been shutdown if there are no plans to start-up again the same day.

A. The valve located before the seal air filter should be closed. This will manually turn off the seal air to the rotary valve.

B. The fabric filter exhaust fan attached to the top of fabric filter should be turned off manually from the sorbent silo.

C. The fabric filter system should be turned off manually from the sorbent silo.

1.6 SI Alarms and Trips

Alarms and Trips for the SI and humidification systems

1.6.1 SI Alarms:

A. Sorbent screw pump not in auto.

B. Sorbent rotary seal not in auto.

C. Sorbent screw pump fault.

D. Sorbent rotary feeder fault.

E. Sorbent silo level low.

F. Sorbent silo empty.

G. Sorbent silo level high.

H. SI fan failed to stop.

I. Transport air blower failed to stop.

J. Sorbent screw pump failed to stop.

K. Sorbent rotary feeder failed to stop.

L. SI fan not in auto.

M. SI fan fault.

N. Sorbent transport air Blower

O. Sorbent feed train not ready to run.

P. Humidification water pump not in auto.

Q. Humidification water pump fault.

R. Atomizing air compressor No. 1,2,3 fault.

S. Atomizing air compressor No. 1,2,3 not ready to start.

T. Sorbent weigh hopper failed to fill.

U. Upper SI air solenoid damper fault.

V. SI nozzle cooling fan fault.

W. Lower SI air solenoid damper fault.

X. Sorbent diverter valve fault.

1.6.2 <u>SI Trips</u>:

A. Conditions that cause the sorbent rotary feeder to trip:

- Humidification system failure.
- Stop sequence initiated.
- Sorbent transport blower stopped.
- Transport air below minimum.
- SI fan stopped.
- Emergency stop push button depressed.
- Sorbent screw pump stopped.
- Boiler load below designate MWe
- Boiler trip initiated.
- Upper S.I. air valve closed with diverter valve in higher position.
- Lower S.I. air valve closed with diverter valve in lower position.
- Malfunction of diverter valve.

B. Conditions that cause sorbent screw pump trip:

- Sorbent screw pump stopped by stop sequence.
- Sorbent transport blower stopped.
- Transport air flow below minimum.
- SI fan stopped.
- Emergency stop push button depressed.
- Seal air permissive "A" not satisfied.
- Boiler load below designated minimum.
- Boiler trip initiated.

- Sorbent screw pump running more than designated time period with seal air pressure not satisfied.

C. Conditions that cause SI system to trip.

- East humidification duct discharge temperature low-low.
- West humidification duct discharge temperature low-low.
- East ESP discharge temperature low-low.
- West ESP discharge temperature low-low.
- Boiler trip initiated.
- Emergency trip initiated.
- Operator commanding close humidification water solenoid valves.
- East atomizing air/water pressure low for more than designated time
- West atomizing air/water pressure low for more than designated time
- Atomizing air header pressure low.
- Humidification water pump stopped.

1.7 Humidification System Pre-operational Checklist

The following items should be verified by a physical walkdown of the system before any startup can begin. This section does not discuss maintenance items that require attention.

A. The three manual shutoff valves located near the service water supply and the humidification spray pump should be opened.

B. Shutoff valves in the air compressor condensate drain piping should be open.

C. The instrument shutoff valves located just before atomizing air pressure transmitters must be open.

D. The automatic drain on the atomizing air receiver tank should be checked to see that it is functioning properly and any manual bypass valves should be closed.

E. The manual shutoff valves located before the water strainers should be open.

F. The manual shutoff valves located before the atomizing air pressure indicators should be open.

G. The flow path on the humidification duplex strainer should be selected by turning the handle all the way to the right or left against a stop.

1.8 Humidification System Post Operational Checklist

The following tasks should be completed after the system has been shutdown if there are no plans to start up again the same day.

A. The three manual shutoff valves located near the service water supply and the humidification spray pump should be closed.

B. The manual shutoff valves located before the water strainers should be closed.

C. The manual shutoff valves located before the atomizing air pressure indicators should be closed.

1.9 Humidification System Alarms and Trips (see 1.6 SI Alarms and Trips)

1.10 Ash Handling

1.10.1 Ash/Sorbent

This system has only one alarm: CONVEYING COMPLETE. This is not actually an alarm condition; it alerts the operator that the system has shut down through the use of a red flashing light. Shut down will occur only after the final line purge of the system. When this alarm condition occurs, the operator should close the water supply valve.

1.10.2 CO_2 Injection

The CO_2 injection system is not equipped with any alarms or system trips. A two-pen recorder will record the upstream and discharge sluice water pH. The recorder is located in the boiler control room where it can be monitored routinely by the operators. The CO_2 system was controlled thru the WDPF which provided control, monitoring and alarming capabilities.

2.0 LAKESIDE GR-SI OPERATING PROCEDURES

2.1 Pre-Operational Checklist

Prior to operating the boiler in the normal mode (coal firing only) or any of the subsystems (GR and/or SI) a walkdown should be performed to insure that the respective systems are ready to start. The usual checklist should be followed to insure that the boiler is ready for a start. In addition, the following checklist should be followed for the equipment that has been added to permit GR and/or SI operation. The following provides an operator checklist of GR-SI equipment and the required condition of that equipment for normal firing of the Lakeside No. 7 Boiler. The checklist is divided into subsections of FGR, OFA, SI, and Electrical Power Equipment. (Note: The fans, dampers, and valves described below do not operate until the forced draft fan has started, and the applicable H-O-A selector switches are set to auto.)

2.1.1 Flue Gas Re-Circulation (FGR)

1. Seal air system (silver piping) valves to all FGR/NG injection nozzle wallboxes must be open. Aspirating air (green piping) is off except for nozzle removal during boiler firing.
2. If FGR/NG Nozzles requiring cooling water are being utilized then the cooling water valves must be open to the FGR/NG nozzles and flow verified by the individual flow meters. The cooling water system will have a main header valve and an individual valve (10 total) for each nozzle. On the first start-up, each valve will be fully opened. EER will adjust the water flow with the individual valves to limit over-cooling and water wastage. These valves will remain in this set position unless nozzle maintenance is required. Cooling water will then be turned on and off only at the main header valve. Cooling water is not required when using the ceramic nozzles.
3. Seal air system (silver piping) valves to all furnace temperature transmitter wallboxes (3) must be open. Cooling (instrument air) to the furnace transmitters must be on. The instrument air flow rate has been adjusted via the pressure regulator. Shut-off valves are provided.
4. Either of the FGR cooling fans must be running. The respective outlet damper for the operational fan and the cooling header tight shut-off damper must be open. The damper for the automatic stand-by fan must be closed. Operation of this equipment can be monitored from the Westinghouse WDPF Controls in the control room.

5. FGR fan discharge damper must be closed. The seal air fan for this damper must be running. The damper for this seal air fan must be open when the seal air fan is running. Operation of this equipment can be monitored from the Westinghouse WDPF Controls in the control room.
6. The FGR Multiclone inlet damper must be closed. The associated seal air fan must be operating, and it's small control damper must be open. Operation of this equipment can be monitored from the Westinghouse WDPF Controls in the control room.
7. Individual gas ducting shut-off valves at each FGR nozzle must be open to admit cooling air to the nozzles.
8. Individual natural gas shut-off valves to each FGR nozzle should be closed.

2.1.2 <u>OFA</u>

Verify that the OFA air control dampers are closed to their bleed/cooling air position. The minimum air flow setting will be adjusted into the damper drive mechanism by EER on initial start-up by EER through the use of temporary thermocouples mounted to the OFA Nozzle. This adjustment will not allow the dampers to fully close from the control system, allowing sufficient air to pass to properly cool the nozzles at high load. Operation of this equipment can be monitored from the Westinghouse WDPF Controls in the control room.

2.1.3 <u>SI</u>

1. Seal air system (silver piping) valves to all SI nozzle wallboxes are open. Aspirating Air (green) is closed.
2. SI Fan discharge damper must be closed. Operation of this equipment can be monitored from the Westinghouse WDPF Controls in the control room.
3. Either of the SI cooling fans must be operating. The respective outlet damper for the operational fan, either must be open. The damper for the automatic stand-by fan must be closed. Operation of this equipment can be monitored from the Westinghouse WDPF Controls in the control room.
4. Injection air balancing valves (butterfly type) at the sorbent nozzles must be open. (Later into start-up each of these butterfly valves will be adjusted to a certain position and locked with the thumbscrew, in order to distribute the air evenly to the ten SI nozzles).

5. The sorbent transport line pinch valve must be closed to prevent hot furnace gases from flowing back into the SI system.

2.1.4 GR

As a starting point for this procedure, it is assumed that the procedure outlined in Sections 2.1.1 through 2.1.3 has been followed and that the boiler is in operation in a normal mode. Note: The required verifications and checks will be annotated with a (W) or a (L) to reflect whether the verification or check should be done at the (W)estinghouse Control Screens or (L)ocally.

1. Check to be sure that all applicable electrical circuit breakers for GR equipment are closed:

    FGR Fan Variable Frequency Drive, FGR Seal Air Fan, Power Panels East FGR Nozzle Cooling Fan, West FGR Nozzle Cooling Fan, Power Panel, FGR Fan Turning Gear
    Purge Panel, OFA Dampers, VFD A. C. Unit

2. Open Nozzle gas shut off valves.
3. Verify that the boiler is operating above the minimum setting of 180,000 lbs/hr of steam flow.(W)
4. Verify that the Furnace Temperature Transmitters are operating properly and are indicating temperatures above the minimum required temperature of 1700° F each. Note that only two of the three transmitters need to indicate above the minimum temperature to satisfy the permissive to operate the GR System; however, all three transmitters should be working correctly for reliable operation of the system. (W)
5. At the FGR Fan, verify that the cooling water to the FGR Fan bearings (1 bearing on each side of the fan) is flowing at a rate of at least 1 GPM as indicated on the water flow meters located at the bearings. (L)
6. Verify that the FGR Fan is clear of any obstructions or any personnel and that fan is ready to operate. (L)
7. Verify that the hand switches for the FGR Fan and the FGR Turning Gear are in the Auto positions. (L)

8. Verify that the FGR Fan rotor is not turning and that the FGR Fan Discharge Damper is closed. (W or L)

9. Verify that the Multiclone Inlet Damper is closed and that the seal air fan and associated damper are operating.
(W or L)

10. Verify that both of the Natural Gas Shut-Off Valves are closed. (W or L)

11. At the FGR Nozzles, verify that the cooling water to the Natural Gas Only Injection Nozzles and Flue Gas Recirculation Nozzles is flowing at a rate of at least 5 GPM as shown on the water flow meters for each nozzle. (L)

2.1.5 SI

As a starting point for this procedure, it is assumed that the procedure outlined in Section 2.1.1 through 2.1.3 has been followed and that the boiler is in operation in a normal mode and the load is greater than minimum for SI operation (to be determined during testing).

1. Check to be sure that all applicable electrical circuit breakers for SI equipment are closed:

    Sorbent Transport Air Blower, Sorbent Equipment Instrument Air Compressor, Sorbent Rotary Valve, Power Transformer, Sorbent Fluidizing Blower, Sorbent Screw Pump, SI Air Fan, Power Panels, North SI Cooling Fan, South SI Cooling Fan, Sorbent Screw Pump Filter, Collector, Instruments, Sorbent Silo Fabric Filter Collector, Compressed Air Dryer, SI Control Damper

2. Start Sorbent Equipment Instrument Air Compressor
3. Place Instrument Air Dryer in Service
4. Open Weigh Hopper Discharge Slide Gate
5. Start Fabric Filter Exhaust Fan

2.1.6 Additional Items to be Monitored

Table 2-1 is an operator checklist of additional items that can and should be monitored from the control room on a regular basis to ensure proper operation of the systems above, as well as to gain familiarity with the GR-SI hardware and software.

TABLE 2-1

OPERATOR CHECKLIST TO BE MONITORED

ITEM	PROCESS AND INDICATIONS
Temp Transmitter	Measures furnace gas temperatures in the reburning zone, low temperatures indicates port pluggage (WDPF)
OFA Flow Transmitter	Measures air flow through the OFA ducts, can be used to ensure cooling air flow (WDPF)
OFA Temp Transmitter	Can be used to ensure cooling flow (WDPF)
OFA Duct Pressure	Can be used to verify cooling flow (local)
SI Air	Can be used to verify cooling flow (WDPF)
SI Duct Air Pressure	Can be used to verify cooling flow (local)
Multiclone Hopper Level	Used to indicate full hopper for ash pulling, can be used for indication of inlet damper being open w/o FGR operation

2.1.7 Electrical Power System

Power for the GR-SI system is provided by three motor control centers as follows:

MCC 1 - Electrical building at the silo area

MCC 2 - Control room floor, northeast of boiler no. 7

MCC 3 - 5th floor, west of boiler no. 7

Power is supplied to the MCC's as follows:

MCC 1 - Fed directly from the outside silo area transformer (City grid)

MCC 2 - Fed from MCC 1,600 Amp breaker

MCC 3 - Fed from house power, 150 Amp breaker on Floor 2, south of Unit No.7 just behind the FGR Fan

Also, there exists a power panel which is fed from MCC 2, and is located on the control room floor on the outside wall of the personnel elevator shaft. The equipment which was described above in the FGR, OFA, and SI system which uses electrical power for it's operation is listed in Table 2-2 with it's power source.

TABLE 2-2
ELECTRICALLY POWERED EQUIPMENT

<u>FGR</u>	
East FGR Cooling Fan	MCC 3
West FGR Cooling Fan	MCC 3
East FGR Cooling Fan Damper	* AIR/WDPF
West FGR Cooling Fan Damper	AIR/WDPF
FGR Fan Discharge Damper	AIR/WDPF
FAN Discharge Damper Seal Fan	MCC 2
Damper	AIR/WDPF
Multiclone Inlet Damper	AIR/WDPF
Multiclone Damper Seal Fan	MCC 2
Damper	AIR/WDPF
FGR Fan Turning Gear	MCC 3
<u>OFA</u>	
East OFA Control Damper	PPL2
West OFA Control Damper	PPL2
<u>SI</u>	
SI Fan Discharge Damper	AIR/WDPF
North SI Cooling Fan	MCC 3
South SI Cooling Fan	MCC 3
North SI Cooling Fan Damper	AIR/WDPF
South SI Cooling Fan Damper	AIR/WDPF

*"AIR/WDPF" means that the particular piece of equipment uses instrument air for it's motive power with control power (110v) directly from the Westinghouse WDPF.

2.2 <u>Startup</u>

2.2.1 <u>GR and OFA</u>

Note: The required verifications and checks will be annotated with a (W) or a (L) to reflect whether the verification or check should be done at the (W)estinghouse Control Screens or (L)ocally.

1. Open the Manual Shut Off Valve
2. Open the Natural Gas Manual Shut Off Valve

   This valve is used to prevent all gas flow to the natural gas flow regulating equipment. This valve is located on the 2nd floor just south of the Lakeside

Control Room. Verify that there is approximately 30 psig of natural gas pressure on the high pressure side of the Natural Gas Pressure Reducing Regulator and approximately 15 psig natural gas pressure on the low pressure side.(L) The low pressure indication is a permissive for the FGR System including the FGR Fan. If the low pressure side is low it can be increased by adjusting the Natural Gas Pressure Reducing Regulator. If the high pressure side is too low to provide 15 psi of low pressure, then the testing cannot be accomplished and the natural gas supply company, CILCO, must be contacted. Visually inspect for any apparent leaks or flow problems. (L)

3. Put Fuel / Air Master Control in Manual.

The Furnace Fuel / Air Master must be put in the MANUAL mode to prevent it from responding to changes in air flow caused by starting and stopping of various fans, and by the changes in excess O2 from the injection of natural gas. The Furnace Fuel / Air Master should then be set to the optimum air to coal ratio of 9.06:1 (Stoichiometry of 1.15). This can be verified by using the calculations displayed on the Boiler Performance Monitoring System (BPMS), or by using the values shown on the boiler control displays to calculate the ratio with the following formula.

$$\text{Air to Coal Ratio} = \frac{\text{East Cyclone Total Air} + \text{West Cyclone Total Air}}{\text{East Total Coal Flow} + \text{West Total Coal Flow}}$$

Note: A perfect air to coal ratio cannot be maintained continuously, only an average ratio of 9.06:1 needs to be achieved.

4. Start FGR Fan

The FGR fan turning gear may be started at any time. If the turning gear is to be used its respective circuit breaker at G-MCC-3 must be closed. The turning gear may be started from the WDPF digital control station screen or from the local Hand-Off-Auto switch. To start the turning gear from the WDPF the local Hand-Off-Auto switch must be in the Auto position. The turning gear also starts automatically once the FGR fan has been shutdown. The turning gear/motor arrangement will drive a Formsprag clutch at a constant speed that will turn the fan impeller once the fan speed has slowed to a speed matching that of the clutch. Using the touch screen or the keyboard on the operators control station, start the FGR Fan. This control is located on the Digital Control Station I screen or by using a pop-up control on the GR /_OFA Overview screen. The pop-up display is accessed by touching the screen at the diagram of the fan. Verify that the currently operating GR Nozzle Cooling Fan stops and the associated dampers close. Verify that the FGR Discharge Damper opens and that the associated seal air fan stops and the seal air fan damper closes (W or L). Open the Multiclone Inlet Damper by using the same digital control station or by using the dedicated pop-up control for the damper. Verify that the associated seal air fan stops and the seal air damper closes (W or L). Start the FGR Purge Taps by using the same digital control station screen. The Purge Taps are on a timing circuit and will purge the venturi flow sensing lines after they have been started and after the timer has expired. The timer automatically resets after each time-out sequence. Verify that the FGR Venturi is indicating flow. This flow should be about 1500 SCFM at minimum speed of the FGR Fan (W). The FGR Fan should be allowed to run at minimum flow for approximately one hour. This will allow the fan and FGR ducts to heat-up slowly enough to preclude any thermal expansion problems and to assure that the flue gas temperature is within the temperature range needed for accurate flow measurements. It is possible to use the fan immediately; however, it is not recommended. Raise the FGR Fan flow to the optimum setting of approximately 6,000 SCFM by using the GR and OFA M/A Station Screens or by using the pop-up control on the GR and OFA Overview Screen. Raise the fan speed slowly while monitoring the motor amps that are displayed on the screens. DO NOT OVER ACCELERATE THE FAN. The Variable Frequency Drive for this fan has circuitry that will trip the fan if it overloaded too quickly. The practice has been to increase the demand to the fan until the motor amps indicate the maximum limit of 130 amps. Then wait until the amps fall back and level off to a consistent indication. Note that as the fan speed is increased, the "leveled off" ampere indication becomes higher and higher. Whenever the fan is stopped either by the operator or a trip, it must be allowed to coast to a complete stop before starting again. A timing circuit has been programmed into the controls to prevent the fan from being restarted too soon. If the fan's housing temperature is above 200 degrees F., the controls will prevent the FGR Turning Gear from being turned-off. Monitor the temperatures of the fan housing and bearings.(W) If at any time the fan housing temperature rises above 750 degrees F, or if the bearing temperatures rise above 145 degrees F, the system and the fan should be shut down.

5. Raise OFA above minimum required flow

Before beginning to inject natural gas, assure that the burnout area of the furnace has enough excess O2 by increasing the total OFA flow above the minimum required flow of 6,000 SCFM. The OFA Dampers are controlled by using the GR and OFA M/A Station Screen or by using the pop-up window on the GR and OFA Overview Screen. It is best to adjust each damper to a position that provides a flow of approximately 3,500 SCFM at each OFA duct. This will assure that the total flow does not fall below the minimum. Note that since the OFA is diverted from the Secondary Air Ducts, the FD Fan automatically adjusts to maintain a consistent FD Fan Air pressure of 30 in.W.C.

6. Open Natural Gas Block Valves and Start Natural Gas Flow

Assure that the plant's flame detection system is in service and is not likely to trip a cyclone feeder due to poor operation of the flame scanners. If either one of the flame scanners is not indicating a bright flame, the scanner should be cleaned or adjusted before continuing. Open the Natural Gas Block Valves. These valves are opened together automatically by using the controls on the Digital Control Station I or by using the pop-up control on the GR / OFA Overview. There will be a momentary indication of gas flow due to gas flowing up to the Natural Gas Control Valve. Wait for the gas flow to reduce to verify that there are no apparent leaks. If leaks are present; close the block valve immediately and close the manual shut off valve for the natural gas. Open the Natural Gas Control Valve to a minimum flow of about 250 SCFM. The control span on this valve is such that it does not allow gas to flow until the"Open" output demand to this valve is above approximately 11%. A flow of 250 SCFM is on the low end of the control span, and therefore all increases in demand after 11% should be made slowly.

7. Raise Natural Gas Flow and OFA Flow Symmetrically

Begin increasing the OFA flow and the Natural Gas Flow in proportion to each other. It has been found that for every one "click" of Natural Gas increase, there should be two "clicks" of OFA increase on each OFA Damper. Monitor excess O2 during this time to verify that the excess O2 does not fall below 1% or rise above 7% (W). Continue raising both the Natural Gas and the OFA until the desired flow of Natural Gas or NOx reduction is achieved. This can be verified by the BPMS or by the main control screens.

8. Adjust OFA to obtain proper Stoichiometries

After the desired Natural Gas Flow has been set, adjust the OFA flow to achieve the desired stoichiometry. The stoichiometry can be verified on the BPMS.

9. Monitoring during operation

Monitor the system to verify all equipment is functioning properly. Monitor the CO emission as displayed on the BPMS to verify proper burn-out of the Natural Gas. Ideally the CO emissions should remain below 100 ppm.

2.2.2 SI

Note: The required verifications and checks will be annotated with a (W) or a (L) to reflect whether the verification or check should be done at the (W)estinghouse Control Screens or (L)ocally.

1. Start Sorbent Silo Compressor and Air Dryer

Start the Sorbent Silo Compressor and the Air Dryer locally by using the control panels located on each piece of equipment. Verify that the equipment is working correctly and that there are no apparent leaks. Verify that the coalescing water filters are drained. (L)

2. Open Sorbent Hopper Manual Slide Gate Valve

Open the Sorbent Hopper Manual Slide Gate Valve located just above the Sorbent Rotary Feeder Valve.

3. Start the Discharge Fan for the Sorbent Screw Pump Baghouse

Using the hand switch located on the South wall of the Sorbent Silo, start the Discharge Fan for the Sorbent Screw Pump Baghouse. This fan draws air through the filters in the baghouse which is then discharged outside of the silo. This air is entrained in the Sorbent and is removed by the Screw Pump during transport to the blower box.

4. Put Fuel / Air Master Control in Manual.

The Furnace Fuel / Air Master must be put in the MANUAL mode to prevent it from responding to changes in air flow caused by starting and stopping of various fans. The Furnace Fuel / Air Master should then be set to the optimum air to coal ratio of 9.06:1 (Stoichiometry of 1.15). This can be verified by using the calculations displayed on the BPMS, or by using the values shown on the boiler control displays to calculate the ratio with the following formula.

5. Begin Sootblowing

Start the Unit #7 Sootblowers by using the new microprocessor controls. Select all of the Retractable Blowers (all of the IK's) and the Air Heater Sootblower, and operate until the boiler efficiency is shown to be acceptable. Note that the Wall Blowers (all of the IR's) are not used. Continue operating the Sootblowers during the SI process to maintain the needed boiler efficiencies. The optimum sequence that has been determined is:

First Cycle	IK-3, IK-4, IK-8
Second Cycle	IK-3, IK-5, IK-7, IK-8
Return to First Cycle	

The Air Heater Sootblower should be operated about once an hour during Sorbent Injection.

6. Begin Ash Pulling

Start the Ash Pulling sequence on continuous. The addition of the Sorbent and the continuous Sootblowing cause the hoppers to fill at a faster rate than normal, especially the Rear-Pass Hoppers. The ash must be pulled using the dry system due to the alkalinity of the Sorbent.

7. Start SI Fan

Start the SI Fan by using the Digital Control Station II or the pop-up window on the SI Overview. Verify that the fan's outlet damper opens and a flow is indicated on the SI Air Transmitter. The normal minimum flow is usually around 1500 SCFM. (W) Verify that the currently selected SI Cooling Fan stops and that the associated damper closes. (W or L)

8. Start Sorbent Transport Air Blower

Start the Sorbent Transport Air Blower by using the Digital Control Station II or the pop-up window on the SI Overview. Verify that the Weigh Hopper Air Slide Valve opens momentarily and closes again. This valve will cycle automatically during operation to provide air inside the Weigh Hopper to prevent plugging. Verify that the Transport Air Pinch Valve is open. (W or L) Verify that air flow, temperature, and pressure are indicated from their respective transmitters. (W) This information can be found on the SI Overview Screen. Raise the demand output to the Transport Air Control Valve (G-FV-102) using the SI M/A Station Screen or the pop-up window on the SI Overview. This will assure that air is flowing into the boiler and that boiler gas cannot be back-fed into the system. Set the Transport Air to the minimum flow of 250 ACFM or the flow needed for testing of 500 ACFM. Note that this valve closes as the demand output is increased. This is because the valve allows the transport air to be vented to atmosphere when it is open. As the valve closes, it diverts more air through the transport line.

9. Start Sorbent Screw Pump

Start the Sorbent Screw Pump using the Digital Control Station II or the pop-up window on the Sorbent Overview Screen. Verify that the Seal Air Valve opens and that a Low Pressure indication is not present on the Sorbent Overview Screen. (W)

10. Start Sorbent Rotary Feeder Valve

Start Sorbent Rotary Feeder Valve using the Digital Control Station II. There is not a pop-up window to start this valve. Note that at 0% demand output, the rotary valve is turning at minimum speed.

11. Raise the SI Air to desired Flow

Using the SI M/A Station Screen or the pop-up window, open the inlet damper to the SI Fan to increase the SI Air flow to 5,000 SCFM.

12. Raise the Sorbent Transport Air Flow to the desired Rate

If the Sorbent Transport Air Flow has not already been set to the required flow of 500 ACFM, do so now.

13. Raise the Sorbent Flow to the desired Rate

Raise the Sorbent flow using the pop-up window or the SI M/A station for the Rotary Feeder Valve. The desired flow is determined by the boiler load and the optimum Ca/S ratio (Calcium to Sulfur ratio). This is the hardest flow to maintain due to the inherent problems of dry bulk solids handling. The desired flow is measured by monitoring the average of the displayed flow values. This is easiest to do if the trend function is used on the Westinghouse Control Station.

14. Monitoring during operation

Monitor the system to verify all equipment is functioning properly. Monitor the Sorbent Flow to maintain constant flow. It is possible for the flow to stop due to plugging of the weigh hopper. If this happens, the Weigh Hopper Solenoid Valve should correct this when it opens. This valve is on a timing circuit. This cycle time can be adjusted by changing the values of the timers "On" and "Off" data points in the point data detail window.

2.3 Shutdown

2.3.1 GR and OFA

Note: The required verifications and checks will be annotated with a (W) or a (L) to reflect whether the verification or check should be done at the (W)estinghouse Control Screens or (L)ocally.

1. Reduce Natural Gas Flow and OFA Flow Symmetrically to 0% Output

Begin Reducing the Natural Gas flow and the OFA flows in relation to each other. Reduce the flows by reversing the method for increasing the flows (found in the start up section). Monitor the CO emission to verify controlled stoichiometry as in start up and normal operation. Continue reducing flows until the demand outputs to the Natural Gas Control Valve and the OFA Dampers are at 0%. Verify that the Natural Gas Flow returns to 0. (W) This flow indication does not immediately reset to 0 due to the nature of the flow element. The flow element is a turbine meter which must "spin-down" after flow through the meter has stopped. Verify that the OFA flows have returned to the minimum flow.(W) This minimum flow is dependent on the boiler load. It is nominally 1.8 KSCFM at each OFA duct.

2. Close Natural Gas Block Valves

Close the Natural Gas Block Valves using the Digital Control Station I or by using the pop-up control on the GR/OFA Overview. Verify that the Natural Gas Bleed Valve opens to vent gas trapped between the block valves to the atmosphere. (W)

3. Stop FGR Fan

If the fan has been used for the GR process and is cooling, the turning gear should only be stopped once the FGR fan housing temperature has cooled enough that there is little chance that the fan shaft could take a set. The turning gear may be stopped from the WDPF once the fan housing has cooled. The fan housing temperature is indicated on a WDPF digital control station screen. Once the housing temperature has been below 300 °F for 4 hours an alarm on the WDPF will indicate that it is OK for the turning gear to be stopped. The turning gear can be stopped from the digital control station screen or at the local H-O-A switch. The FGR fan should never be started if the fan impeller is still turning. The fan will continue to turn for some time after the turning gear has stopped. A timer within the WDPF will prevent the startup of the fan if it is still turning after the turning gear motor has stopped. Reduce the FGR Fan speed by lowering the demand output to 0%. THIS SHOULD BE DONE SLOWLY. Verify that the FGR flow has returned to minimum (about 1500 SCFM) (W). Stop the FGR Fan by using the digital control station or by using the pop-up control for the fan. Close the Multiclone Inlet Damper (G-CV-608) by using the digital control station or by using the dedicated pop-up control for the damper. Verify that the associated seal air fan starts and the seal air damper opens. (W)

4. Put Fuel / Air Master Control in Automatic.

Wait for the boiler to settle after making changes to the total air flow from the starting of cooling fans and seal air fans. Adjust the Fuel / Air Master to the desired ratio and put the controller in the automatic mode. Verify that the air flows and the excess O2 return to the normal operating state. (W)

2.3.2 SI

Note: The required verifications and checks will be annotated with a (W) or a (L) to reflect whether the verification or check should be done at the (W)estinghouse Control Screens or (L)ocally.

1. Reduce the Sorbent Flow to 0% Output

Reduce the Sorbent flow using the pop-up window or the SI M/A station for the Rotary Feeder Valve. Note that at 0% demand output the valve is still turning at a very slow speed, some Sorbent will still fed into the system until the valve is stopped by using the Start/Stop Station.

2. Stop the Sorbent Rotary Feeder

Stop Sorbent Rotary Feeder Valve using the Digital Control Station II. There is not a pop-up window to stop this valve.

3. Stop the Sorbent Screw Pump

Stop the Sorbent Screw Pump using the Digital Control Station II or the pop-up window on the Sorbent Overview Screen.

4. Reduce the SI Air Fan to 0% Output

Using the SI M/A Station Screen or the pop-up window on the SI Overview Screen, close the inlet damper to the SI Fan to reduce the SI Air flow to minimum.

5. Reduce the Sorbent Transport Air Flow to 0% Output

Verify that the Sorbent Transport Air Pressure has decreased to a constant reading. This indicates that the transport line is clear of any Sorbent. (W) Reduce demand output to the Transport Air Control Valve to 0% by using the SI M/A Station Screen or the pop-up window on the SI Overview. Note that reducing the demand output to this valve actually opens the valve to allow more transport air to be vented to atmosphere.

6. Stop the Sorbent Transport Air Blower

Stop the Sorbent Transport Air Blower by using the Digital Control Station II or the pop-up window on the SI Overview. Verify that the Transport Air Pinch Valve is closed. (W or L)

7. Stop the SI Air Fan

Stop the SI Fan by using the Digital Control Station II or the pop-up window on the SI Overview. Verify that the fan's outlet damper closes. Verify that the currently selected SI Cooling Fan starts and that the associated damper opens. (W or L) The normal cooling fan flow is usually around 750 SCFM.

8. Put Fuel / Air Master Control in Automatic.

Wait for the boiler to settle after making changes to the total air flow from the starting of cooling fans and seal air fans. Adjust the Fuel / Air Master to the desired ratio and put the controller in the automatic mode. Verify that the air flows and the excess O2 return to a normal state. (W)

9. Continue Sootblowing and Ash Pulling

After the current sootblowing cycle finishes, select all of the retractable sootblowers and the Air Heater Sootblower and blow them at least three times. This should remove most of the Sorbent that may have deposited in the back passes of the boiler. Continue pulling ash on the dry system during the sootblower sequence and continue until all hoppers have been cleared of any ash and Sorbent laden ash.

10. Stop Sorbent Silo Air Compressor and Air Dryer

If the Sorbent Silo Compressor is no longer needed. (i.e., SI has been completed and Ash Removal has been completed), stop the Sorbent Silo Air Compressor and the Air Dryer. Check the compressor control panel display for any advisories that may be displayed. The controller is programmed to display advisories such as needed filter changes and etc.. Notify the appropriate maintenance group for any service needed.

11. Close Sorbent Hopper Manual Slide Gate Valve

Close the Sorbent Hopper Manual Slide Gate Valve located just above the Sorbent Rotary Feeder Valve.

12. Stop the Discharge Fan for the Sorbent Screw Pump Baghouse

Using the hand switch located on the South wall of the Sorbent Silo, stop the Discharge Fan for the Sorbent Screw Pump Baghouse.

2.4.1 Permissives, Alarms and Trips For GR & OFA

Permissives:

Refer to screen 2030 for all system start permissives.

GR System Ready

1. FGR Injection Fan in Remote
2. FGR Fan Turning Gear in Remote
3. Furnace Temp. Permit
4. Gas Pressure > minimum
5. Gas Flow Control Valve at minimum
6. Load (Steam Flow) > minimum
7. F.D. Fan Running
8. Both Gas Shut off valves closed
9. Coal in service permit

FGR Injection Fan Start Permits

1. FGR Fan Rotor is Stopped
2. Multiclone Inlet is Closed
3. FGR Discharge is Closed
4. GR System Ready

FGR Injection System Ready

1. FGR Injection Fan Running
2. Multiclone Inlet Open
3. FGR Discharge damper open
4. Gas Recirc. Flow > Min

OFA System Ready

1. GR System Ready
2. OFA Dampers Released to Modulate
3. OFA Flow > Min

Gas Valve Permits

1. Boiler Trip Not Present
2. GR-SI Emergency Stop not Present

3. FGR Fan Running
4. FD Fan Running
5. Boiler Load > Minimum
6. Any Two of Three Optical Pyrometer temps. above 1700°F
7. Coal in Service Permit
8. OFA System Ready
9. GR System Ready
10. FGR Injection System Ready
11. Natural Gas Press OK
12. Aspirating Air Valve Closed

Alarms

These alarms indicate GR start permissives that are not satisfied.

1. FGR Injection Fan not in auto
2. Coal Flow not in service
3. Natural Gas Shut-off valves open
4. Gas Pressure is low
5. Gas Flow Control Valve below minimum
6. Load (MW) below minimum
7. Furnace temperature below minimum
8. FGR Fan fault
9. Natural Gas Pressure is High

Miscellaneous Alarms

1. FGR Turning Gear not running
2. FGR Inboard Bearing Vibration high
3. FGR Outboard Bearing Vibration high
4. FGR Inboard Bearing Temperature high
5. FGR Outboard Bearing Temperature high
6. FGR Housing Temperature high
7. OK to Stop FGR Turning Gear
8. FGR Fan Discharge Shut-off Damper fault

9. Seal Air Fan fault
10. GR Nozzle cooling Fan A fault
11. GR Nozzle cooling Fan B fault
12. FGR Flow Tap Purge Panel fault

GR and OFA Trips

(which shut off flow of Natural Gas)

1. Boiler Trip
2. Emergency Stop Initiated by Operator
3. FD Fan trip
4. Indication OFA System not ready
5. GR Permissives not satisfied

2.4.2 Permissives, Alarms and Trips for SI

Permissives

SI Fan Start Permits

1. SI Fan in Remote
2. SI Fan Discharge Damper Closed
3. SI Fan Control Damper at Min.

Transport Air Blower Start Permit

1. Transport Air Blower in Remote
2. SI Fan Running
3. SI Fan Discharge Damper Open

Feed Train Ready Permits

1. Transport Air Blower Running
2. Transport air flow > Min (time delay)
3. Sorbent Screw Pump in Remote
4. Sorbent Rotary Feeder in Remote
5. Seal Air Press > Min
6. Weigh Hopper Level > Min

Sorbent Screw Pump Start Permits

1. Sorbent Screw Pump in Remote
2. Feed Train Ready
3. Boiler Trip not Present
4. Boiler Load > Min
5. GR-SI Emergency Stop not Present
6. SI Fan Running
7. Transport Air Blower Running

Sorbent Rotary Feeder Start Permits

1. Sorbent Rotary Feeder in Remote
2. Sorbent Screw Pump Running
3. Boiler Trip no Present
4. SI Fan Running
5. GR-SI Emergency Stop not Present
6. Boiler Load > Min.
7. Transport Air Flow > Min.
8. Sorbent Transport Air Blower Running
9. Feed Train Ready

Alarms

1. Sorbent Screw Pump not in auto.
2. Sorbent Rotary Seal not in auto.
3. Sorbent Screw Pump fault.
4. Sorbent Rotary Feeder fault.
5. Sorbent Silo level low.
6. Sorbent Silo empty.
7. Sorbent Silo level high.
8. SI Fan failed to stop.
9. Transport Air Blower failed to stop.
10. Sorbent Screw Pump failed to stop.
11. Sorbent Rotary Feeder failed to stop.

12. SI Fan not in auto.
13. SI Fan fault.
14. Sorbent Transport Air Blower fault.
15. Sorbent Transport Air Blower not in auto.
16. Sorbent Feed Train not in auto.
17. Sorbent Weigh Hopper failed to fill.
18. SI Fan Discharge S.O. Damper Fault.
19. SI Nozzle Cooling Fan "A" Fail to Start.
20. SI Nozzle Cooling Fan "B" Fail to Start.

Trips

1. Conditions that cause Sorbent Rotary Feeder trip.
    A. Stop sequence initiated.
    B. Sorbent Transport Blower stopped.
    C. Transport air below minimum.
    D. SI Fan stopped.
    E. Emergency Stop Push Button depressed.
    F. Sorbent Screw Pump stopped.
    G. Boiler load below designate M.W.
    H. Boiler trip initiated.
2. Conditions that cause Sorbent Screw Pump trip.
    A. Sorbent Screw Pump stopped by stop sequence.
    B. Sorbent Transport Blower stopped.
    C. Transport Air flow below minimum.
    D. SI Fan stopped.
    E. Emergency Stop Push Button depressed.
    F. Seal Air Permissive "A" not satisfied and Sorbent Screw Pump running more than 10 sec.
    G. Boiler Load below designated minimum.
    I. Boiler trip initiated.

APPENDIX B

HENNEPIN & LAKESIDE SAMPLING SCHEDULES

TABLE I. HENNEPIN PROJECT MONITORING IN PHASES I AND II

MEASUREMENT	SAMPLE TYPE	FREQUENCY	LOCATION
	COMPLIANCE		
WATER			
Flow Rate	single reading estimate	once/wk	existing ash pond discharge
pH	grab sample	once/wk	existing ash pond discharge
Total Suspended Solids	24 hr composite	once/wk	existing ash pond discharge
Oil and Grease	grab sample	twice/mo	existing ash pond discharge
GASEOUS EMISSIONS			
Coal Composition sulfur, ash, Btu, moisture	24 hr composite	daily	coal hopper
Coal Flow	24 hr composite	daily	coal feed belt
	SUPPLEMENTAL		
WATER			
General Use Water Quality Standards	composite	once	Illinois River - 100 ft upstream and downstream of ash pond discharge
GASEOUS EMISSIONS			
NOx	continuous	(1)	economizer inlet
CO	continuous	(1)	economizer inlet
O2	continuous	(1)	economizer inlet
SO2	continuous	(1)	economizer inlet
WORKER HEALTH			
Hearing		once (2)	TBD
Pulmonary Function		once (2)	TBD
TSP		once (2)	TBD

1. Two-week period in Phase I.
2. Must occur prior to initiation of Phase III.

TABLE 2. HENNEPIN PROJECT MONITORING IN PHASE III-page 1 of 3

MEASUREMENT	SAMPLE TYPE	FREQUENCY	LOCATION
	COMPLIANCE		
WATER			
Flow Rate	24 hr total	daily	ash pond discharge
pH	grab sample	once/wk	ash pond discharge
Total Suspended Solids	24 hr composite	once/wk	ash pond discharge
Oil and Grease	grab sample	once/mo	ash pond discharge
Groundwater (pH, TDS, S, B, Mn, Ca, Chloride, Nitrate, Nitrite, Sulfite, Sulfate)	grab sample	(1)	groundwater monitoring wells
GASEOUS EMISSIONS			
Coal Composition (sulfur, ash, Btu, moisture)	24 hr composite	daily	coal hopper
Coal Flow	24 hr composite	daily	coal feed belt
	SUPPLEMENTAL		
WATER			
Ill. River General Use Water Quality Standards (35 Ill. Adm. Code 302)	grab sample	once (4)	Illinois River - 100 ft upstream and downstream of ash pond discharge
Sluice water analyses(2)	grab sample	monthly (3)	ash sluice line to existing ash pond
GASEOUS EMISSIONS			
NO_x	extractive probe/ chemiluminescent	(8) continuous	stack breeching
SO_x	extractive probe/ NDUV	(8) continuous	stack breeching
CO	extractive probe/ NDIR	(8) continuous	stack breeching
CO_2	extractive probe/ NDIR	(8) continuous	stack breeching
O_2	extractive probe/ paramagnetic	(8) continuous	stack breeching
HC	extractive probe/ FID	(8) continuous	stack breeching

TABLE 2. HENNEPIN PROJECT MONITORING IN PHASE III

MEASUREMENT	SAMPLE TYPE	FREQUENCY	LOCATION
GASEOUS EMISSIONS			
Particulate Loading	Method 17	(4)	ESP inlet
	Method 5	(4)	ESP outlet
Particle Size Distribution	cascade impactors	(4)	ESP inlet and outlet
Resistivity	cyclonic flow probe	(4)	ESP inlet
N2O	extractive	(5)	stack breeching
SOLID BY-PRODUCTS			
Ash (6)	composite of	(7)	bottom ash hopper, economizer, and ESP hoppers #1 and #2
WORKER HEALTH			
Hearing	N/A	once/yr	TBD
Pulmonary Function	N/A	once/yr	TBD
TSP	N/A	once/yr	TBD
AIR			
Noise	single reading	once (4)	near equipment installation
Ambient Dust	single reading-Hi-Volume Sampler	once (4)	upwind and downwind of sorbent silo

TABLE 2. FOOTNOTES- HENNEPIN PROJECT MONITORING IN PHASE III

1. Monitoring will occur once prior to GR-SI operation, quarterly until the program is completed, and quarterly through closure and post-closure periods.
2. Water will be analyzed for arsenic, barium, boron, cadmium, chromium, iron, lead, mercury, oil and grease, pH, selenium, silver, sulfates, TDS, TSS, zinc, and flow rate.
3. Sampling will be conducted once prior to Phase III, then monthly for the first six months of long-term testing.
4. Measurements will be taken once prior to Phase III, then once during long term testing.
5. Samples will be collected once prior to Phase III, and once during long-term testing. Additional testing will then be done if the N_2O concentration is greater than 5 ppm.
6. Ash will be monitored for mineral analysis, free CaO, total organic carbon, sulfate, COD, phenol, cyanide, nitrate, chloride sulfide, specific gravity, fineness, pozzolanic activity, soundness, PAH and pH. Paint filter and TCLP tests will also be conducted.
7. Sampling will be conducted once prior to Phase III. During long-term testing sampling and analysis will be conducted monthly for the first 3 months.
8. Sampling will occur once prior to Phase III, and CEM data will be reported during long-term testing.

TABLE 3. LAKESIDE PROJECT MONITORING IN PHASES I AND II

MEASUREMENT	SAMPLE TYPE	FREQUENCY	LOCATION
	COMPLIANCE		
WATER			
Flow Rate	single reading estimate	once/wk	ash pond discharge
pH	grab sample	twice/wk	ash pond discharge
Total Suspended Solids	24 hr composite	twice/wk	ash pond discharge
Oil and Grease	grab sample	twice/mo	ash pond discharge
Flow Rate	single reading estimate	once/wk	outfall 008
pH	grab sample	once/wk	outfall 008
Total Suspended Solids	8 hr composite	once/wk	outfall 008
Oil and Grease	grab sample	once/wk	outfall 008
Iron	8 hr composite	once/wk	outfall 008
GASEOUS EMISSIONS			
Opacity	in-situ optical	continuous	stack
	SUPPLEMENTAL		
GASEOUS EMISSIONS			
NOx	extractive probe/ chemiluminescent	continuous (2)	air heater inlet
CO	extractive probe/ NDIR	continuous (2)	air heater inlet
O2	extractive probe/ paramagnetic	continuous (2)	air heater inlet
SO2	extractive probe/ NDUV	continuous (2)	air heater inlet
CO2	extractive probe/ NDIR	continuous (2)	air heater inlet
HC	extractive probe/ FID	continuous (2)	air heater inlet
Particulate Loading	Method 17	see note 2	ESP inlet
	Method 5	see note 2	ESP outlet
Particle Size Distribution	cascade impactors	see note 2	ESP inlet and outlet
Resistivity	cyclonic flow probe	see note 2	ESP inlet
N2O	extractive	see note 2	air heater inlet

TABLE 3. LAKESIDE PROJECT MONITORING IN PHASES I AND II

MEASUREMENT	SAMPLE TYPE	FREQUENCY	LOCATION
	SUPPLEMENTAL		
WATER			
pH, sulfates	grab sample	once	sluice line discharge
pH, sulfates	grab sample	once	sluice water intake (Lake Springfield)
SOLID BY-PRODUCTS			
Ash (1)	grab sample	(2)	Ash Hoppers
WORKER HEALTH			
Hearing	NA	once (3)	TBD
Pulmonary Function	N/A	once (3)	TBD
TSP	N/A	once (3)	TBD
AIR			
Noise	single reading	once (3)	near equipment installation
Ambient Dust	single reading	once (3)	near coal pile

1. Ash will be monitored for the following parameters: *mineral analysis*, TCLP, *total organic carbon*, cyanide chloride, sulfide, specific gravity, fineness, PAH, and pH.
2. Measurements will be taken once during Phase I.
3. Must occur prior to initiation of Phase III.

TABLE 4. LAKESIDE PROJECT MONITORING IN PHASE III

MEASUREMENT	SAMPLE TYPE	FREQUENCY	LOCATION
	COMPLIANCE		
WATER			
Flow Rate	single reading estimate	once/wk	ash pond discharge
pH	grab sample	twice/wk	ash pond discharge
Total Suspended Solids	24 hr composite	twice/wk	ash pond discharge
Oil and Grease	grab sample	twice/mo	ash pond discharge
Flow Rate	single reading estimate	once/wk	outfall 008
pH	grab sample	once/wk	outfall 008
Total Suspended Solids	8 hr composite	once/wk	outfall 008
Oil and Grease	grab sample	once/wk	outfall 008
Iron	8 hr composite	once/wk	outfall 008
GASEOUS EMISSIONS			
Opacity	in-situ optical	continuous	stack
	SUPPLEMENTAL		
WATER			
pH, sulfate	grab sample	see note 1	sluice line discharge
pH, sulfate	grab sample	see note 1	sluice water intake (Lake Springfield)
GASEOUS EMISSIONS			
NO_x	extractive probe/ chemiluminescent	continuous	air heater inlet
SO_x	extractive probe/ NDUV	continuous	air heater inlet
CO	extractive probe/ NDIR	continuous	air heater inlet
CO_2	extractive probe/ NDIR	continuous	air heater inlet
O_2	extractive probe/ paramagnetic	continuous	air heater inlet
HC	extractive probe/ FID	continuous	air heater inlet
Particulate Loading	Method 17	see note 1	ESP inlet
	Method 5	see note 1	ESP outlet

TABLE 4. LAKESIDE PROJECT MONITORING IN PHASE III, continued

MEASUREMENT	SAMPLE TYPE	FREQUENCY	LOCATION
GASEOUS EMISSIONS			
Particle Size Distribution	cascade impactors	see note 1	ESP inlet and outlet
Resistivity	cyclonic flow probe	see note 1	ESP inlet
N2O	extractive	see note 2	air heater inlet
SOLID BY-PRODUCTS			
Ash	grab sample	see note 3	ESP hopper
WORKER HEALTH			
Hearing	N/A	once/yr	TBD
Pulmonary Function	N/A	once/yr	TBD
AIR			
Noise	single reading	once (1)	near equipment installation
Ambient Dust	single reading	once (1)	near coal pile

1. Measurements taken once during Phase III long-term testing.
2. N2O measurements taken once during long-term testing. Additional testing will then be done if the N2O concentration is greater than 5 ppm.
3. Ash sampling will be conducted monthly for the first three months of the long-term testing period.

APPENDIX C

HENNEPIN & LAKESIDE
TEST DATA

TABLE C-1. RESULTS OF GR TEST SERIES (AVERAGE OF TEST PERIODS)

Date 1991	Test ID	Load (MWe)	NOx Emiss. (ppm)	NOx Emiss. (lb/MBtu)	CO Emiss. (ppm)	Excess Oxygen (%, wet)	FGR (scfm)	Gas Heat percent of Total	Coal Zone SR	Reburn Zone SR	Exit Zone SR	Burner Tilt (deg)
14-Jun	GR-33A	70	390	0.532	–	–	0	0	1.15	1.19	1.19	-27
15-Jun	GR-33A	70	405	0.552	–	2.20	0	0	1.13	1.18	1.18	-27
17-Jun	GR-33A	70	347	0.473	5	2.20	39	0	1.13	1.13	1.18	-27
17-Jun	GR-33C	70	309	0.421	7	2.50	1	0	1.08	1.08	1.16	-26
17-Jun	GR-33E	70	200	0.273	6	2.30	0	0	0.99	0.99	1.16	-26
17-Jun	GR-33F	70	290	0.395	8	1.50	0	0	1.09	1.09	1.11	-24
17-Jun	GR-33G	70	250	0.341	80	1.00	0	0	1.05	1.05	1.07	-23
17-Jun	GR-33H	70	392	0.534	5	2.30	0	0	1.15	1.15	1.15	-27
18-Jun	GR-37C1	70	247	0.333	6	2.30	7,294	10	1.10	1.01	1.17	-21
18-Jun	GR-37C2	70	224	0.302	3	2.20	7,304	10	1.31	1.20	1.35	-27
18-Jun	GR-37A1	70	208	0.279	5	2.80	7,504	16	1.10	0.94	1.20	-27
18-Jun	GR-37A2	70	202	0.271	2	2.70	7,599	16	1.33	1.14	1.40	-27
18-Jun	GR-37A3	70	226	0.303	6	2.90	6,030	15	1.14	0.98	1.23	-26
18-Jun	GR-37A4	70	378	0.515	8	2.20	3,822	0	1.15	1.15	1.15	2
19-Jun	GR-34B	60	352	0.480	12	2.70	322	0	1.16	1.17	1.19	26
19-Jun	GR-34A	60	358	0.488	8	2.90	1,864	0	1.19	1.20	1.21	0
19-Jun	GR-35A1	60	161	0.215	19	2.10	7,479	19	1.08	0.90	1.16	-1
19-Jun	GR-35A2	60	382	0.521	5	2.70	4,242	0	1.17	1.17	1.18	12
20-Jun	GR-35D	70	188	0.251	20	1.90	7,678	17	1.06	0.89	1.14	0
20-Jun	GR-36A	70	190	0.254	15	2.40	8,000	19	1.11	0.92	1.17	-23
20-Jun	GR-36B1	70	173	0.231	19	2.00	6,911	19	1.08	0.89	1.14	-21
20-Jun	GR-36B2	70	204	0.272	8	2.50	5,015	19	1.12	0.93	1.17	-22
20-Jun	GR-36B3	70	184	0.246	33	1.90	2,544	20	1.07	0.88	1.12	-7
20-Jun	GR-36B4	70	427	0.582	8	2.50	2,503	0	1.16	1.16	1.17	-6
21-Jun	GR-39A	60	364	0.496	9	2.40	577	0	1.12	1.13	1.17	10
21-Jun	GR-39C	60	160	0.214	10	2.20	7,080	19	1.10	0.91	1.17	-13
21-Jun	GR-39B	60	204	0.275	8	2.70	7,239	11	1.10	1.00	1.19	-10
22-Jun	GR-38C1	50	380	0.518	9	2.80	1,907	0	1.17	1.17	1.21	25

TABLE C-1. RESULTS OF GR TEST SERIES (AVERAGE OF TEST PERIODS) continued

Date 1991	Test ID	Load (MWe)	NOx Emiss. (ppm)	NOx Emiss. (lb/MBtu)	CO Emiss. (ppm)	Excess Oxygen (%, wet)	FGR (scfm)	Gas Heat percent of Total	Coal Zone SR	Reburn Zone SR	Exit Zone SR	Burner Tilt (deg)
22-Jun	GR-38C2	50	429	0.585	8	3.10	1,877	0	1.21	1.22	1.23	16
22-Jun	GR-38B1	40	359	0.489	11	3.00	1,886	0	1.16	1.17	1.22	27
22-Jun	GR-38B2	40	408	0.556	9	2.90	1,788	0	1.21	1.22	1.22	27
24-Jun	GR-41A	70	192	0.259	20	1.90	6,896	10	1.07	0.97	1.13	-24
24-Jun	GR-41B	70	154	0.206	23	1.70	6,928	18	1.06	0.88	1.12	-27
24-Jun	GR-41C1	70	166	0.222	18	1.60	5,533	18	1.06	0.88	1.12	-26
24-Jun	GR-41C2	70	413	0.563	9	2.00	5,542	0	1.14	1.14	1.14	-23
24-Jun	GR-41C3	70	361	0.492	9	2.10	80	0	1.09	1.10	1.14	-24
25-Jun	GR-42A	40	296	0.404	11	3.40	233	0	1.19	1.20	1.26	27
25-Jun	GR-42B	40	180	0.245	16	3.40	113	0	0.95	0.95	1.23	27
25-Jun	GR-42C1	40	224	0.305	18	4.60	131	0	0.97	0.98	1.33	27
25-Jun	GR-42C2	40	388	0.529	16	4.20	10	0	1.30	1.31	1.32	27
1-Jul	GR-33A	70	371	0.506	9	2.30	197	0	1.13	1.13	1.16	-21
11-Jul	GR-33A	70	331	0.451	22	2.30	251	0	1.27	1.28	1.31	14
12-Jul	GR-37A	60	161	0.215	31	2.00	8,407	18	1.10	0.91	1.15	-24
16-Jul	GR-40B	40	270	0.364	14	3.30	7,000	11	1.10	1.00	1.24	14
16-Jul	GR-40C	40	220	0.293	13	3.10	6,857	22	1.13	0.90	1.23	14
16-Jul	GR-40D1	40	240	0.321	14	3.50	4,945	17	1.15	0.97	1.25	14
16-Jul	GR-40D2	40	399	0.544	14	3.30	5,770	0	1.21	1.22	1.22	27
16-Jul	GR-40D3	40	331	0.451	14	3.30	5,792	0	1.08	1.08	1.22	21
12-Nov	GR-33A2	70	269	0.367	23	1.97	6	0	1.07	1.08	1.14	-12
13-Nov	GR-42A1	45*	348	0.474	5	2.77	33	0	1.11	1.12	1.19	27
13-Nov	GR-42A2	45*	305	0.416	5	3.37	16	0	1.08	1.09	1.24	27
15-Nov	GR-45B	45	189	0.253	31	2.89	2,647	18	1.07	0.90	1.20	27
15-Nov	GR-45C	45	180	0.241	114	2.84	3,429	18	1.08	0.91	1.20	27
15-Nov	GR-45D	45	177	0.237	55	2.87	4,472	18	1.08	0.90	1.19	27
15-Nov	GR-45E	45	178	0.238	57	2.93	4,752	18	1.08	0.90	1.20	27
[illegible]-Nov	GR-46B	45	17[illegible]	[illegible]	45	3.05	2,610	18	1.08	0.91	1.21	26

TABLE C-1. RESULTS OF GR TEST SERIES (AVERAGE OF TEST PERIODS) continued

Date 1991	Test ID	Load (MWe)	NOx Emiss. (ppm)	NOx Emiss. (lb/MBtu)	CO Emiss. (ppm)	Excess Oxygen (%, wet)	FGR (scfm)	Gas Heat percent of Total	Coal Zone SR	Reburn Zone SR	Exit Zone SR	Burner Tilt (deg)
19-Nov	GR-46C	45	173	0.231	38	2.97	3,550	19	1.08	0.90	1.20	27
19-Nov	GR-46D	45	162	0.217	108	2.83	4,523	18	1.07	0.90	1.19	27
19-Nov	GR-46E	45	165	0.221	205	2.98	4,721	18	1.08	0.91	1.22	27
21-Nov	GR-46B2	45	150	0.200	3	2.82	2,885	19	1.07	0.90	1.19	-8
22-Nov	GR-46D3	45	171	0.228	41	3.07	4,448	18	1.10	0.92	1.21	26
23-Nov	GR-50A	45	171	0.229	3	2.88	3,016	15	1.08	0.94	1.20	4
23-Nov	GR-50B	45	179	0.241	3	2.95	3,030	12	1.09	0.97	1.20	-2
23-Nov	GR-50C	45	188	0.253	3	2.86	3,054	10	1.08	0.98	1.19	0
7-Dec	GR-44A	70	186	0.249	2	2.84	2,777	18	1.09	0.92	1.19	3
10-Dec	GR-33A1	70	370	0.504	2	2.40	0	0	1.14	1.15	1.16	-23
10-Dec	GR-33A2	70	390	0.532	2	2.30	0	0	1.09	1.10	1.16	22
10-Dec	GR-39A1	60	325	0.443	2	2.93	0	0	1.13	1.14	1.20	3
10-Dec	GR-39A2	60	261	0.356	2	3.04	0	0	1.09	1.10	1.21	2
11-Dec	GR-44C2	70	163	0.218	3	2.99	4,383	18	1.12	0.94	1.21	-6
11-Dec	GR-44B2	70	176	0.235	2	2.97	3,591	18	1.10	0.92	1.20	-6
11-Dec	GR-44A2	70	184	0.246	2	2.88	3,057	18	1.10	0.92	1.20	-6
11-Dec	GR-43A1	70	164	0.219	2	2.20	3,096	18	1.07	0.89	1.15	-6
11-Dec	GR-43B1	70	152	0.203	2	2.26	3,603	18	1.06	0.89	1.15	-6
11-Dec	GR-43C1	70	141	0.188	2	2.18	4,542	18	1.06	0.89	1.15	-6
12-Dec	GR-44A3	70	166	0.222	4	2.77	2,622	18	1.08	0.90	1.19	4
12-Dec	GR-43A2	70	157	0.210	8	2.24	2,653	18	1.09	0.91	1.15	2
12-Dec	GR-51A1	70	206	0.276	2	3.02	2,662	14	1.08	0.94	1.21	1
12-Dec	GR-51A2	70	184	0.247	3	2.91	4,419	14	1.07	0.93	1.20	1
12-Dec	GR-51B	70	207	0.276	3	3.16	4,472	12	1.08	0.97	1.22	1
		AVG	254	0.343	18	2.64	3,278	9	1.11	1.02	1.19	0
		MAX	429	0.585	205	4.60	8,407	22	1.33	1.31	1.40	27
		MIN	141	0.188	2	1.00	0	0	0.95	0.88	1.07	-27

TABLE C-2. RESULTS OF GR-SI TEST SERIES (AVERAGE OF TEST PERIODS)

Date 1991	Test ID	Load (MWe)	Sorbent Injection Elevation	Gas Heat Input (%)	Plant O2 (%, wet)	NOx Emiss. (lb/MBtu)	SO2 non-GR Baseline (lb/MBtu)	SO2 GR Baseline (lb/MBtu)	SO2 Emiss. (lb/MBtu)	Ca/S Molar Ratio	Total SO2 Reduction (%)	Sorbent SO2 Reduction (%)	Ca Util. (%)	Sorbent Jet Vel. (ft/sec)	Coal Burner Tilt (Deg)
2-Aug	GRSI-1A	45	Lower	17.4	3.20	0.281	5.12	4.12	2.55	2.07	50.27	38.22	18.46	150	13
6-Aug	GRSI-1F	75	Upper	17.5	2.70	0.237	5.02	3.98	1.85	1.96	63.18	53.52	27.31	290	1
6-Aug	GRSI-1D	60	Upper	17.7	3.10	0.269	5.02	3.97	1.76	1.83	64.89	55.67	30.42	300	6
6-Aug	GRSI-1C	60	Lower	17.9	3.10	0.237	5.02	3.97	2.20	1.83	56.11	44.57	24.36	160	-18
7-Aug	GRSI-1G	58	Upper	17.6	3.30	0.310	5.36	4.32	2.08	2.02	61.19	51.75	25.62	300	18
8-Aug	GRSI-1H	60	Lower	17.7	3.60	0.283	5.18	4.17	1.76	2.10	66.00	57.78	27.52	150	-10
9-Aug	GRSI-1IB	70	Upper	15.5	3.30	0.351	5.35	4.29	1.98	2.07	63.01	53.91	26.04	280	-1
9-Aug	GRSI-1IA	70	Upper	15.5	3.10	0.315	5.35	4.29	2.11	2.06	60.49	50.77	24.65	290	2
12-Aug	GRSI-2A	71.5	Upper	15.5	3.20	0.311	5.37	4.27	2.05	2.25	61.75	51.87	23.05	280	-7
14-Aug	GRSI-3C	70	Upper	17.8	2.80	0.261	5.42	4.43	2.86	1.24	47.25	35.53	28.65	240	2
14-Aug	GRSI-3B	70	Upper	17.9	3.10	0.265	5.42	4.43	3.14	1.17	42.09	29.21	24.96	200	-3
14-Aug	GRSI-3A	70	Upper	18.0	2.80	0.278	5.42	4.43	3.20	1.10	40.91	27.75	25.23	150	1
19-Aug	GRSI-4	DIS	Lower	–	3.40	0.241	5.30	4.33	1.83	1.99	65.58	57.82	29.06	150	-8
20-Aug	GRSI-5	DIS	Lower	–	3.60	0.254	5.31	4.37	1.72	2.12	67.60	60.63	28.60	160	-3
21-Aug	GRSI-6BL	65	Lower	17.8	2.50	0.218	5.14	4.13	1.92	1.90	62.59	53.48	28.15	150	-21
21-Aug	GRSI-6BH	65	Upper	17.6	2.50	0.235	5.14	4.13	2.13	1.89	58.64	48.58	25.70	270	1
21-Aug	GRSI-6AL	45	Lower	18.2	2.70	0.191	5.14	4.13	1.94	1.74	62.28	53.07	30.50	160	-2
21-Aug	GRSI-6AH	45	Upper	18.4	3.50	0.313	5.14	4.13	2.03	1.95	60.41	50.73	26.02	280	27
22-Aug	GRSI-7C	65	Upper	17.8	3.20	0.279	5.31	4.35	2.37	2.21	55.43	45.63	20.65	250	12
22-Aug	GRSI-7B	65	Upper	17.6	3.20	0.278	5.31	4.35	2.47	1.79	53.42	43.19	24.13	240	16
22-Aug	GRSI-7A	65	Upper	17.8	3.30	0.282	5.31	4.35	2.66	1.29	49.87	38.84	30.11	240	6
23-Aug	GRSI-8B	65	Upper	17.6	2.90	0.255	5.15	4.11	2.08	2.04	59.62	49.35	24.19	260	15
23-Aug	GRSI-8A	65	Upper	18.0	2.80	0.226	5.15	4.11	2.60	1.73	49.53	36.68	21.20	250	8
26-Aug	GRSI-9D	55	Upper	17.8	2.80	0.254	5.37	4.32	2.49	1.81	53.63	42.34	23.39	280	15
26-Aug	GRSI-9C	55	Lower	17.8	2.90	0.191	5.37	4.32	2.23	1.83	58.53	48.42	26.46	150	-19
26-Aug	GRSI-9B	50	Lower	17.9	2.60	0.263	5.37	4.32	2.47	1.70	54.06	42.86	25.21	150	8
26-Aug	GRSI-9A	50	Upper	18.4	2.90	0.259	5.37	4.32	2.75	1.63	48.81	36.30	22.27	250	27
27-Aug	SI-3C	70	Upper	0.0	3.40	0.515	5.08	5.08	2.35	2.44	53.61	53.61	21.97	240	4
27-Aug	SI-3B	70	Upper	0.0	3.30	0.518	5.08	5.08	2.99	1.76	41.18	41.18	23.40	240	-1
27-Aug	SI-3A	70	Upper	0.0	3.30	0.513	5.08	5.08	3.79	0.96	25.29	25.29	26.34	250	3
28-Aug	GRSI-10B	70	Upper	17.7	2.90	0.285	5.16	4.25	2.25	1.82	56.36	46.93	25.78	250	7
[illegible]-Aug	GRSI-10A	70	Upper	18.0	2.80	0.277	5.16	4.25	2.92	1.02	43.47	31.24	30.63	250	1

TABLE C-3. GR EMISSIONS SUMMARY

Test I. D.	Test Date	Test Duration (hr:min)	Gross Power (MWe)	Gas Heat (%)	Coal SR	Reb SR	Burn-out SR	Exit SR	OFA (%)	CEMS O2 (%, dry)	Plant O2 (%, wet)	COc (ppm)	CO2c (%)	NOxc (ppm)	NOx (lb/MBtu)	NOx Reduc. (%)	SO2c (ppm)	SO2 (lb/MBtu)	HCc (ppm)
GR-6B	7/28/93	0:54	33	23.4	1.17	0.89	1.24	1.26	28	3.67	2.93	174	14.3	266	0.352	63.26	2426	4.509	1.6
GR-5C	7/28/93	0:26	33	23.4	1.14	0.87	1.23	1.24	29	3.60	2.82	228	14.3	264	0.350	63.51	2409	4.470	1.0
GR-5A	7/29/93	0:60	35	23.2	1.16	0.88	1.22	1.23	28	3.48	2.81	87	14.4	288	0.383	61.20	2512	4.609	0.9
GR-4A	7/29/93	0:13	35	21.8	1.14	0.90	1.23	1.23	27	3.59	3.00	64	14.4	302	0.401	59.34	2544	4.733	1.0
GR-3A	7/30/93	0:49	34	19.6	1.14	0.92	1.21	1.22	26	3.27	2.68	83	14.6	303	0.403	58.61	2624	4.874	4.6
GR-2A	7/30/93	0:60	34	16.1	1.16	0.98	1.23	1.24	22	3.26	2.69	27	14.7	351	0.469	52.30	2726	5.106	2.2
GR-5D	7/30/93	0:51	35	23.1	1.16	0.87	1.22	1.23	28	3.52	2.91	82	14.4	322	0.429	56.60	2535	4.713	0.9
GR-5E	7/30/93	0:54	34	22.0	1.16	0.87	1.22	1.23	28	3.46	2.75	141	14.4	321	0.426	56.70	2515	4.676	0.9
GR-5F	7/30/93	0:60	34	22.0	1.12	0.88	1.20	1.21	28	3.61	2.60	432	14.3	323	0.429	56.04	2606	4.661	16.7
GR-5G	7/30/93	0:66	36	22.8	1.08	0.86	1.17	1.17	28	3.48	2.78	82	14.3	289	0.384	61.11	2601	4.651	0.0
GR-16B	8/2/93	0:50	28	22.0	1.14	0.89	1.22	1.23	27	4.00	3.46	28	14.4	308	0.411	62.78	2525	4.703	0.0
GR-16A	8/2/93	0:50	28	22.0	1.12	0.87	1.20	1.21	27	3.86	3.21	34	14.6	286	0.370	60.64	2510	4.682	0.1
GR-16C	8/2/93	0:50	28	22.6	1.18	0.82	1.26	1.28	28	4.17	3.66	7	14.5	314	0.418	62.22	2487	4.640	0.0
GR-14A	8/2/93	0:60	28	25.0	1.16	0.87	1.20	1.21	27	3.86	3.21	41	14.4	277	0.368	60.06	2420	4.488	0.1
GR-13A	8/2/93	0:60	28	20.6	1.16	0.82	1.26	1.28	28	4.00	3.68	7	14.6	316	0.422	51.69	2517	4.691	0.0
GR-12A	8/2/93	0:50	26	18.0	1.11	0.82	1.24	1.23	26	4.17	3.63	6	14.6	334	0.446	48.88	2562	4.700	0.0
GR-11A	8/2/93	0:50	26	18.6	1.11	0.84	1.21	1.21	22	3.85	3.34	6	14.7	374	0.501	42.52	2644	4.951	0.0
GR-25A	8/11/93	0:50	19	23.9	1.14	0.89	1.25	1.26	29	3.84	3.01	134	14.1	204	0.271	65.35	2372	4.404	3.5
GR-25B	8/11/93	0:60	19	23.9	1.17	0.91	1.28	1.27	28	3.86	3.16	85	14.1	216	0.285	63.46	2343	4.350	1.1
GR-25C	8/11/93	0:60	20	24.0	1.19	0.93	1.28	1.28	28	3.65	2.83	104	14.1	217	0.289	63.17	2347	4.350	2.1
GR-24A	8/11/93	0:60	19	22.2	1.18	0.92	1.28	1.28	26	3.62	2.99	70	14.1	223	0.296	62.10	2401	4.467	0.9
GR-22A	8/11/93	0:28	19	17.0	1.17	1.00	1.27	1.27	22	3.69	3.13	21	14.3	268	0.358	53.96	2542	4.761	0.0
GR-16D	8/12/93	0:60	27	23.2	1.14	0.88	1.23	1.24	28	3.13	2.36	486	14.3	243	0.322	63.24	2450	4.571	18.7
GR-15E	8/12/93	0:60	27	23.1	1.14	0.89	1.24	1.24	28	3.00	2.30	461	14.3	226	0.299	65.94	2452	4.559	19.0
GR-15F	8/12/93	0:57	27	23.3	1.14	0.88	1.24	1.24	28	2.82	2.78	486	14.3	196	0.261	70.26	2454	4.550	27.1
GR-5A2	8/13/93	0:50	33	24.8	1.09	0.84	1.24	1.24	32	3.85	3.06	253	14.3	308	0.400	57.90	2417	4.406	7.5
GR-8A	8/13/93	0:60	34	24.8	1.16	0.88	1.26	1.25	30	3.88	3.11	164	14.3	326	0.431	55.73	2390	4.434	3.8
GR-5H	8/13/93	0:50	33	24.8	1.16	0.88	1.31	1.30	33	4.62	3.72	105	14.3	351	0.465	51.82	2366	4.390	1.0
GR-5I	8/13/93	0:52	32	24.9	1.16	0.88	1.34	1.33	34	6.02	4.09	44	14.2	368	0.488	48.71	2303	4.420	0.6
GR-15G	8/17/93	0:42	25	21.4	1.13	0.91	1.20	1.20	25	3.54	2.88	31	14.4	280	0.373	56.57	2390	4.466	1.9
GR-15G2	8/17/93	0:51	25	23.8	1.15	0.80	1.21	1.21	26	3.76	3.12	12	14.3	290	0.385	55.11	2316	4.305	0.0
GR-15H	8/17/93	0:50	25	23.6	1.16	0.90	1.30	1.29	30	4.79	3.89	12	14.2	326	0.433	49.40	2290	4.254	0.7
GR-15I	8/17/93	0:50	25	23.6	1.16	0.91	1.34	1.34	33	5.36	4.30	16	14.1	334	0.444	48.37	2283	4.241	0.7
GR-8B	8/18/93	0:53	33	24.8	1.14	0.88	1.24	1.24	29	3.84	3.12	49	14.3	311	0.412	57.08	2324	4.311	0.0
GR-5I	8/18/93	0:56	33	24.8	1.16	0.88	1.33	1.32	33	4.79	3.92	14	14.2	346	0.459	52.15	2317	4.299	0.0
GR-25D	8/19/93	0:46	19	22.2	1.14	0.90	1.27	1.27	29	4.96	4.00	12	14.2	310	0.412	46.92	2360	4.393	0.0
GR-25E	8/19/93	1:00	19	22.2	1.13	0.91	1.27	1.27	28	4.82	4.10	8	14.2	303	0.404	48.01	2347	4.360	0.0
GR-25E2	8/19/93	0:52	19	21.9	0.85	0.78	1.11	1.12	32	3.61	2.96	233	14.2	181	0.254	67.37	2360	4.400	0.0
GR-25F	8/19/93	0:58	19	22.0	0.96	0.77	1.13	1.12	32	3.55	2.98	276	14.2	171	0.227	70.81	2351	4.376	0.0
GR-25G	8/20/93	0:31	19	22.7	1.08	0.86	1.16	1.15	25	3.85	3.12	75	14.4	233	0.310	60.26	2394	4.452	0.0
GR-25G2	8/20/93	0:46	19	25.6	1.08	0.83	1.12	1.12	26	3.65	2.83	225	14.3	222	0.293	67.29	2304	4.272	0.0
GR-25H	8/20/93	0:58	19	25.6	1.08	0.83	1.25	1.24	33	5.05	4.15	19	14.2	276	0.365	53.25	2282	4.230	0.0
GR-25I	8/20/93	0:51	19	25.7	1.08	0.83	1.20	1.19	31	4.49	3.72	23	14.2	252	0.334	57.11	2273	4.213	0.0
GR-25F2	8/20/93	0:48	19	25.9	1.08	0.83	1.20	1.19	31	4.54	3.74	54	14.2	248	0.329	57.67	2261	4.190	0.0
GR-25E3	8/20/93	0:57	19	25.8	1.08	0.82	1.19	1.19	31	4.40	3.60	77	14.2	260	0.345	55.66	2256	4.182	0.0
GR-25D2	8/20/93	0:57	19	25.3	1.08	0.82	1.19	1.19	31	4.24	3.23	203	14.2	264	0.349	55.10	2274	4.206	0.0

Notes: Subscript c denotes correction to 3% O2

NOx reduction from correlated baseline: NOx = 0.522 + 0.0134*(load)

TABLE C-3. GR EMISSIONS SUMMARY (continued)

Test I. D.	Test Date	Test Duration (hr:min)	Gross Power (MWe)	Gas Heat (%)	Coal SR	Reb SR	Burn-out SR	Exit SR	OFA (%)	CEMS O2 (%, dry)	Plant O2 (%, wet)	COc (ppm)	CO2c (%)	NOxc (ppm)	NOx (lb/MBtu)	NOx Reduc. (%)	SO2c (ppm)	SO2 (lb/MBtu)	HCc (ppm)
GR-14A2	8/23/93	0:50	24	24.4	1.00	0.82	1.21	1.21	32	3.80	3.20	326	14.3	220	0.303	64.12	2394	4.443	0.0
GR-15A2	8/23/93	0:58	24	23.2	1.05	0.82	1.22	1.22	32	3.87	3.27	390	14.3	234	0.311	63.25	2412	4.483	0.0
GR-5E2	8/23/93	0:50	31	25.2	1.13	0.86	1.24	1.23	30	3.63	3.00	117	14.2	276	0.366	61.12	2271	4.211	0.0
GR-14A2	8/31/93	0:55	24	25.0	1.14	0.80	1.20	1.28	32	3.77	2.71	353	14.4	269	0.367	57.72	2496	4.020	19.6
GR-15F2	8/31/93	0:50	24	24.1	1.15	0.89	1.27	1.27	30	3.49	2.61	256	14.4	240	0.329	61.01	2618	4.075	0.5
GR-16E2	8/31/93	0:50	24	24.0	1.16	0.89	1.27	1.27	30	3.66	2.40	434	14.4	270	0.370	66.11	2614	4.660	30.0
GR-19A	8/31/93	0:50	24	24.1	1.15	0.89	1.32	1.32	32	4.10	3.13	100	14.4	282	0.376	65.52	2500	4.650	8.6
GR-26B2	9/1/93	0:50	19	26.7	1.16	0.89	1.37	1.30	36	4.00	3.01	81	14.1	213	0.282	63.01	2397	4.442	3.5
GR-1A	9/2/93	1:00	36	11.0	1.16	1.03	1.27	1.27	18	2.53	2.30	70	14.0	302	0.520	40.58	2767	5.210	0.0
GR-5D2	9/2/93	0:35	34	26.0	1.18	0.89	1.22	1.22	27	2.23	1.86	477	14.1	220	0.302	60.92	2430	4.530	0.0
GR-5C2	9/2/93	0:52	33	25.4	1.26	0.86	1.32	1.31	28	3.67	3.16	30	14.2	302	0.400	60.61	2390	4.432	0.0
GR-6D2	9/2/93	0:50	33	25.3	1.26	0.86	1.31	1.31	28	3.60	3.13	28	14.2	322	0.427	66.77	2307	4.420	0.0
GR-26A	9/3/93	0:50	20	23.0	1.20	0.86	1.33	1.32	28	4.23	3.87	33	14.3	260	0.332	67.71	2503	4.060	0.0
GR-25B2	9/3/93	0:50	18	26.6	1.28	0.80	1.36	1.34	27	3.80	3.76	82	14.3	240	0.320	67.34	2436	4.512	0.0
GR-25I2	9/7/93	0:55	19	25.8	1.16	0.88	1.35	1.34	34	4.04	3.76	204	14.3	201	0.266	65.96	2524	4.677	0.0
GR-25J	9/7/93	0:53	19	25.6	1.15	0.89	1.42	1.41	37	5.46	4.47	68	14.3	232	0.308	60.71	2498	4.631	0.0
GR-H2	9/7/93	0:46	20	25.6	1.16	0.88	1.29	1.28	32	3.80	3.05	495	14.3	174	0.231	70.60	2480	4.597	0.0
GR-27B	9/8/93	0:48	18	22.8	1.11	0.88	1.30	1.30	32	4.16	3.05	528	14.4	171	0.227	70.80	2550	4.763	0.0
GR-27C	9/8/93	0.50	18	23.0	1.10	0.88	1.35	1.36	35	4.73	3.04	615	14.3	185	0.246	68.26	2520	4.604	0.0
GR-27D	9/8/93	0:50	19	22.9	1.10	0.89	1.40	1.39	37	5.35	4.23	219	14.2	208	0.276	64.47	2529	4.700	0.0
GR-27E	9/8/93	0:50	18	23.0	1.11	0.88	1.47	1.46	38	6.02	4.82	67	14.2	238	0.316	59.38	2540	4.722	0.0
GR-28A	9/8/93	0:50	18	19.7	1.11	0.82	1.40	1.38	34	6.20	4.17	187	14.4	223	0.298	61.87	2644	4.832	0.0
GR-28B	9/8/93	0:50	19	18.0	1.11	0.84	1.38	1.37	32	4.87	3.87	188	14.5	227	0.304	61.05	2698	5.046	0.0
GR-10A	9/30/93	0:50	23	20.0	1.08	0.84	1.43	1.41	41	5.66	4.60	92	13.8	223	0.286	64.60	2390	4.420	0.0
GR	10/25/93	2:10	26	10.6	1.14	0.95	1.28	1.30	27	3.87	2.77	358	14.1	260	0.360	57.80	2660	4.783	0.0
GR 113B	10/26/93	2:05	24	24.8	1.16	0.89	1.31	1.31	32	4.63	3.49	198	14.2	235	0.312	63.32	2333	4.330	0.0
GR 113A	10/26/93	1:05	25	24.8	1.10	0.86	1.30	1.30	34	4.50	3.38	454	14.3	210	0.279	67.21	2310	4.287	0.0
GR113C	10/26/93	0:30	25	26.0	1.18	0.91	1.30	1.30	30	4.16	3.25	221	14.2	232	0.308	63.81	2293	4.254	0.0
GR 111A	10/26/93	0:50	25	26.0	1.14	0.86	1.25	1.25	31	3.70	2.70	520	14.2	200	0.265	60.87	2272	4.210	0.0
GR 111B	10/26/93	0:50	25	20.1	1.16	0.94	1.26	1.26	26	3.63	2.67	410	14.5	224	0.298	64.97	2407	4.489	0.0
GR 101B	10/27/93	0:50	34	24.7	1.16	0.89	1.28	1.29	32	4.20	3.32	136	14.4	333	0.441	54.57	2397	4.449	0.0
GR 101C	10/27/93	0:50	34	24.9	1.18	0.91	1.30	1.29	30	4.21	3.39	46	14.4	333	0.442	54.53	2372	4.400	0.0
GR 101D	10/27/93	0:50	34	24.8	1.20	0.92	1.30	1.30	28	4.20	3.37	27	14.4	334	0.443	54.35	2332	4.327	0.0
GR 101A	10/27/93	0:50	34	24.7	1.10	0.85	1.30	1.29	34	4.52	3.30	283	14.3	292	0.387	60.15	2322	4.309	0.0
GR 104A	10/27/93	0:30	34	24.9	1.18	0.91	1.30	1.30	30	4.36	3.34	29	14.3	325	0.431	55.65	2298	4.262	0.0
GR 104B	10/27/93	0.29	34	24.9	1.10	0.90	1.30	1.30	30	4.38	3.34	42	14.3	335	0.444	54.24	2294	4.256	0.0
GR 104C	10/27/93	0:30	34	24.8	1.10	0.90	1.29	1.30	30	4.39	3.35	51	14.2	349	0.462	52.39	2301	4.268	0.0
GR 102A	10/28/93	0.50	33	23.7	1.18	0.92	1.30	1.30	30	4.31	3.33	74	14.3	341	0.453	52.90	2415	4.407	0.0
GR 102B	10/28/93	0.50	33	20.1	1.17	0.96	1.29	1.28	26	4.01	3.14	46	14.4	355	0.473	50.88	2485	4.633	0.0
GR 102C	10/28/93	0:50	33	16.1	1.17	1.01	1.28	1.28	21	3.81	3.06	18	14.6	405	0.544	43.57	2620	4.920	0.0
GR 103A	10/28/93	0:50	33	25.6	1.17	0.89	1.25	1.26	28	3.71	2.73	323	14.1	289	0.384	60.12	2365	4.383	0.0
GR 103B	10/28/93	0:50	33	25.7	1.17	0.90	1.34	1.34	33	4.07	3.84	25	14.0	343	0.454	52.85	2368	4.388	0.0

Notes: Subscript c denotes correction to 3% O2

NOx reduction from correlated baseline: NOx = 0.522 + 0.0134*(load)

TABLE C-3. GR EMISSIONS SUMMARY (continued)

Test I.D.	Test Date	Test Duration (hr:min)	Gross Power (MWe)	Gas Heat (%)	Coal SR	Reb SR	Burn-out SR	Exit SR	OFA (%)	CEMS O2 (%, dry)	Plant O2 (%, wet)	COc (ppm)	CO2c (%)	NOxc (ppm)	NOx (lb/MBtu)	NOx Reduc. (%)	SO2c (ppm)	SO2 (lb/MBtu)	HCc (ppm)
GR 112A2	10/29/93	0:30	24	21.4	1.18	0.86	1.28	1.28	26	3.81	2.88	303	14.5	234	0.311	63.05	2471	4.601	0.0
GR 112A	10/29/93	0:25	24	24.1	1.18	0.82	1.30	1.30	28	4.08	3.16	287	14.3	232	0.308	63.41	2399	4.454	0.0
GR 112B	10/29/93	0:30	24	20.4	1.18	0.96	1.30	1.30	26	3.89	3.05	175	14.5	250	0.334	60.34	2409	4.640	0.0
GR 112C	10/29/93	0:30	24	14.8	1.18	1.03	1.30	1.30	21	3.80	3.05	58	14.8	310	0.415	50.60	2637	4.946	0.0
GR-106A	11/10/93	0:15	32	26.0	1.09	0.83	1.20	1.20	31	3.16	1.92	602	14.3	227	0.302	68.12	2306	4.425	0.0
GR-106B	11/10/93	0:30	32	26.0	1.08	0.83	1.25	1.25	33	3.78	2.63	520	14.3	242	0.320	66.32	2371	4.399	0.0
GR-107C	11/10/93	0:30	32	26.1	1.09	0.83	1.24	1.26	34	3.78	2.40	621	14.3	204	0.376	60.39	2351	4.359	0.0
GR--107B	11/10/93	0:30	32	26.1	1.09	0.83	1.24	1.25	33	3.71	2.65	518	14.2	255	0.338	64.38	2345	4.350	0.0
GR-106C	11/10/93	0:30	32	26.3	1.09	0.83	1.29	1.29	35	4.32	3.08	537	14.3	249	0.330	65.19	2340	4.339	0.0
GR-108A	11/10/93	0:10	32	23.8	1.16	0.80	1.30	1.28	31	4.17	3.18	170	14.4	278	0.370	60.95	2388	4.420	0.0
GR-106B	11/10/93	0:30	32	26.0	1.09	0.83	1.26	1.26	33	3.78	2.63	520	14.3	242	0.320	66.32	2371	4.399	0.0
GR-107C	11/10/93	0:30	32	26.1	1.08	0.83	1.24	1.26	34	3.78	2.40	621	14.3	204	0.378	60.39	2361	4.359	0.0
GR--107B	11/10/93	0:30	32	26.1	1.09	0.83	1.24	1.25	33	3.71	2.65	518	14.2	265	0.338	64.38	2345	4.350	0.0
GR-106C	11/10/93	0:30	32	26.3	1.09	0.83	1.29	1.29	35	4.32	3.08	537	14.3	240	0.330	65.19	2340	4.339	0.0
GR	11/15/93	0:41	26	23.0	1.16	0.91	1.30	1.33	30	6.10	3.45	195	14.3	222	0.295	65.83	2414	4.409	0.0
GR	11/16/93	0:16	23	22.0	1.15	0.92	1.30	1.32	29	4.35	3.26	250	14.3	230	0.306	63.27	2337	4.366	0.0
GR 114 A	11/17/93	0:20	23	23.0	1.16	0.91	1.29	1.35	30	4.94	3.06	50	14.4	226	0.301	63.79	2350	4.368	0.0
GR 114 B	11/17/93	0:00	23	23.2	1.14	0.90	1.29	1.35	30	4.82	3.79	50	14.4	225	0.299	64.05	2370	4.404	0.0
GR 114 C	11/17/93	0:20	23	23.1	1.14	0.90	1.28	1.34	30	4.90	3.70	46	14.3	246	0.327	60.60	2377	4.410	0.0
GR	11/23/93	5:22	23	22.2	1.14	0.91	1.30	1.29	30	4.13	3.38	223	14.3	220	0.304	63.44	2432	4.526	0.0
GR	2/16/94	1:38	26	21.4	1.16	0.83	1.28	1.30	28	4.61	3.45	228	14.3	307	0.412	57.96	2440	4.548	0.0
GR	2/17/94	4:51	28	22.2	1.14	0.81	1.28	1.30	28	6.14	3.84	83	14.1	285	0.380	56.61	2360	4.388	0.0
GR	2/18/94	2:04	28	21.2	1.14	0.82	1.24	1.28	28	4.61	3.66	108	14.3	281	0.377	57.78	2418	4.508	0.0
GR	3/28/94	0:37	30	22.2	1.16	0.92	1.26	1.29	27	4.13	3.22	134	14.5	273	0.364	60.39	2462	4.582	0.0
GR	4/6/94	1:00	31	20.1	1.16	0.86	1.25	1.28	24	4.14	3.29	116	14.4	284	0.385	59.01	2513	4.698	0.0
GR-25-25	4/8/94	1:47	26	23.8	1.16	0.80	1.28	1.35	30	6.08	3.65	163	14.2	188	0.249	70.98	1882	3.478	0.0
GR-25-25	4/8/94	2:09	26	23.1	1.18	0.82	1.30	1.34	28	4.46	3.44	300	13.8	209	0.278	67.56	2405	4.469	0.0
GR-25-30	4/8/94	2:48	29	14.3	1.16	1.03	1.32	1.37	23	4.85	3.87	190	14.7	384	0.518	42.99	2690	5.063	0.0
GR-23-25	4/9/94	0:47	20	22.1	1.20	0.97	1.44	1.48	33	6.41	5.05	30	14.1	247	0.328	58.81	2422	4.510	0.0
GR-23-23	4/9/94	5:12	24	23.1	1.17	0.83	1.34	1.40	30	5.26	4.11	57	14.2	275	0.299	64.41	2394	4.451	0.0
GR-23-29	4/9/94	7:29	29	23.4	1.16	0.90	1.31	1.36	31	4.76	3.80	142	14.1	225	0.299	67.02	2342	4.350	0.0
GR-23-30	4/11/94	11:50	30	23.0	1.15	0.91	1.28	1.33	29	4.28	3.51	100	14.2	231	0.308	66.79	2332	4.335	0.0
GR-23-26	4/11/94	0:31	26	23.7	1.15	0.91	1.31	1.37	31	5.21	4.12	23	14.1	219	0.292	66.63	2372	4.407	0.0
GR-23-25	4/12/94	7:45	26	23.6	1.16	0.90	1.31	1.36	31	4.93	4.02	57	14.0	217	0.288	67.08	2332	4.332	0.0
GR-23-30	4/12/94	6:14	30	21.4	1.15	0.93	1.27	1.32	27	4.43	3.54	116	14.2	287	0.383	58.76	2435	4.535	0.0
GR	4/14/94	110:26	27	22.6	1.16	0.82	1.26	1.32	27	4.34	3.45	79	14.0	239	0.318	63.80	2100	4.054	0.0
GR-23-24	4/20/94	0:35	26	23.4	1.15	0.91	1.27	1.33	28	4.52	3.59	28	14.1	233	0.309	63.73	2390	4.443	0.0
GR-23-30	4/21/94	5:51	30	23.0	1.16	0.90	1.28	1.33	29	4.41	3.64	136	14.1	266	0.353	61.98	2238	4.158	0.0
GR	5/17/94	8:33	25	22.6	1.14	0.91	1.25	1.29	27	4.09	3.07	258	14.3	220	0.292	65.83	1885	3.465	0.0
GR	5/18/94	10:03	25	22.7	1.15	0.82	1.28	1.31	29	4.60	3.63	112	14.3	230	0.307	64.41	2464	4.582	0.0

Notes: Subscript c denotes correction to 3% O2

NOx reduction from correlated baseline: NOx = 0.522 + 0.0134*(load)

TABLE C-4. GR OPERATING CONDITIONS

Test I. D.	Test Date	Gross Power (MWe)	Gas Heat (%)	Coal Flow (lb/hr)	Reb Gas (scfm)	FGR (scfm)	Cyclone Air (lb/hr)	OFA Flow (scfm)	Opac (%)	Steam Load (lb/hr)	SSH Steam (F)	SSH Steam (psig)	PSH Steam (F)	Blr Drum (psig)	RhBnk G I (F)	RhBnk G O (F)	AirHtr G O (F)
GR-5B	7/28/93	33	23.4	28,666	1,618	6,976	264,388	23,066	2	300,721	897	881	837	942	893	667	339
GR-6C	7/28/93	33	23.4	28,765	1,618	6,881	258,778	23,784	2	300,836	895	881	837	942	903	674	341
GR-5A	7/28/93	35	23.2	28,467	1,616	6,866	268,670	22,822	3	305,477	898	876	837	940	909	674	340
GR-4A	7/29/93	36	21.8	30,000	1,483	6,894	270,470	22,053	3	305,010	895	876	842	940	910	678	343
GR-3A	7/30/93	34	19.6	30,034	1,336	5,877	270,892	19,958	3	298,822	896	874	831	934	892	665	338
GR-7A	7/30/93	34	16.1	31,886	1,126	6,853	288,118	17,826	3	306,050	894	876	828	940	903	676	339
GR-5D	7/30/93	36	23.1	29,680	1,623	6,886	267,869	23,472	3	307,869	893	876	829	939	923	682	343
GR-5E	7/30/93	34	22.8	30,006	1,624	4,037	270,808	23,492	3	307,736	895	876	825	939	916	681	346
GR-5F	7/30/93	34	22.6	29,690	1,623	3,096	267,858	23,570	3	307,935	894	876	821	939	894	667	340
GR-6G	7/30/93	35	27.8	28,860	1,624	6,902	270,247	23,660	4	311,621	895	878	820	941	911	675	340
GR-16B	8/2/93	20	22.8	24,688	1,241	4,872	221,398	17,864	3	241,513	898	876	819	912	883	659	327
GR-16A	8/2/93	20	22.8	24,830	1,244	4,830	217,088	17,876	3	242,928	896	878	816	912	881	662	328
GR-16C	8/2/93	20	22.6	24,482	1,248	4,886	227,488	17,878	3	242,014	893	878	817	912	906	668	332
GR-14A	8/2/93	20	26.0	23,882	1,306	4,907	218,330	17,876	3	244,307	898	878	818	912	912	670	333
GR-13A	8/2/93	20	20.6	24,876	1,138	4,878	226,682	17,877	3	243,435	893	877	815	912	913	673	333
GR-12A	8/2/93	20	18.6	24,830	1,086	4,980	227,180	17,905	3	242,134	895	876	817	911	919	677	335
GR-11A	8/2/93	20	16.6	26,749	918	4,977	236,043	16,164	3	241,438	896	876	812	910	927	678	336
GR-25A	8/11/93	19	23.9	18,609	1,010	4,846	167,857	16,672	4	178,052	896	881	784	894	823	620	311
GR-25B	8/11/93	18	23.8	18,810	1,010	4,835	171,607	16,663	4	180,033	894	881	786	895	833	622	313
GR-25C	8/11/93	20	24.0	18,643	1,011	4,833	174,203	14,160	4	180,863	896	881	787	895	840	622	314
GR-24A	8/11/93	18	22.2	18,860	932	4,822	172,576	14,120	4	180,294	895	881	786	895	838	622	314
GR-22A	8/11/93	19	17.0	18,630	700	4,864	182,608	11,902	4	177,000	896	878	786	893	842	622	315
GR-15D	8/12/93	27	23.2	24,740	1,287	3,046	222,874	19,387	4	241,487	897	881	788	912	920	664	334
GR-15E	8/12/93	27	23.1	24,830	1,287	3,875	223,657	19,413	4	242,216	895	881	792	913	931	668	336
GR-15F	8/12/93	27	23.3	24,668	1,289	6,800	221,258	19,440	4	242,266	896	881	796	914	922	672	337
GR-6A2	8/13/93	33	24.6	28,771	1,618	6,878	248,686	28,788	4	284,766	894	881	828	937	918	671	338
GR-8A	8/13/93	34	24.8	28,688	1,630	6,840	268,248	24,881	4	296,814	896	881	836	939	919	678	342
GR-5H	8/13/93	33	24.8	28,488	1,635	6,868	267,340	28,391	4	295,450	892	881	834	938	927	681	344
GR-5I	8/13/93	32	24.8	28,682	1,636	6,871	267,847	30,168	6	296,619	893	881	836	937	937	687	347
GR-15G	8/17/93	26	21.4	24,418	1,160	6,066	217,422	18,162	0	233,604	898	881	824	914	868	642	329
GR-15G2	8/17/93	25	23.6	23,864	1,275	6,036	216,811	17,397	0	233,426	895	881	821	913	876	645	331
GR-15H	8/17/93	25	23.6	24,000	1,278	4,968	218,830	21,734	0	233,833	892	881	821	913	880	649	332
GR-15I	8/17/93	25	23.5	24,213	1,278	5,016	219,827	24,257	0	234,261	893	881	822	913	893	653	333
GR-8B	8/18/93	33	24.8	29,318	1,668	6,992	263,491	24,991	3	299,690	897	892	844	952	902	673	345
GR-5I	8/18/93	33	24.8	29,306	1,669	5,990	265,243	30,181	3	301,041	891	891	844	952	924	682	348
GR-25D	8/19/93	19	22.2	19,188	843	3,104	171,652	16,736	6	178,273	896	892	803	906	815	616	314
GR-25E	8/19/93	19	22.2	19,174	843	4,018	171,473	16,726	3	178,937	894	892	804	906	818	619	315
GR-25C2	8/19/93	19	21.9	19,848	866	4,073	148,830	16,703	3	179,425	899	891	789	905	820	615	317
GR-25F	8/19/93	19	22.0	19,661	858	6,859	148,172	16,717	3	178,305	895	892	792	905	816	618	318
GR-25G	8/20/93	19	22.7	18,482	886	5,113	166,057	12,898	4	181,339	895	891	801	907	817	615	314
GR-25G2	8/20/93	19	25.6	18,821	1,109	6,130	168,305	12,924	4	179,989	896	891	805	906	818	616	316
GR-25H	8/20/93	19	25.6	18,870	1,121	6,109	168,673	18,484	4	181,970	890	892	804	906	830	621	316
GR-25I	8/20/93	19	25.7	18,759	1,116	6,109	159,763	16,264	4	180,455	895	892	806	906	829	621	316
GR-25F2	8/20/93	19	25.9	18,613	1,116	5,974	157,578	16,271	4	178,707	895	892	808	906	828	621	317
GR-25E3	8/20/93	19	25.8	18,666	1,116	4,065	158,914	16,257	4	179,454	894	892	802	906	831	619	317
GR-25D2	8/20/93	19	25.3	19,196	1,116	3,023	163,546	16,255	4	178,940	895	892	803	906	807	613	321

TABLE C-4. GR OPERATING CONDITIONS (continued)

Test I.D.	Test Date	Gross Power (MWe)	Gas Heat (%)	Coal Flow (lb/hr)	Reb Gas (scfm)	FGR (scfm)	Cyclone Air (lb/hr)	OFA Flow (scfm)	Opac (%)	Steam Load (lb/hr)	SSH Steam (F)	SSH Steam (psig)	PSH Steam (F)	Blr Drum (psig)	BlrBnk G I (F)	BlrBnk G O (F)	AirHtr G O (F)
GR-14A2	8/23/93	24	24.4	22,467	1,261	5,007	187,740	20,137	3	225,200	893	881	790	909	885	646	321
GR-15A2	8/23/93	24	23.2	22,940	1,186	4,987	188,318	20,652	5	226,924	892	881	796	909	877	651	324
GR-5E2	8/23/93	31	25.2	27,897	1,624	5,961	247,582	24,489	3	282,340	895	881	826	936	960	704	352
GR-14A2	8/31/93	24	25.0	21,438	1,232	5,093	193,200	20,194	5	224,540	895	881	793	907	881	652	323
GR-15F2	8/31/93	24	24.1	21,506	1,170	5,805	194,356	18,974	5	223,314	897	881	795	907	885	656	324
GR-16E2	8/31/93	24	24.0	21,615	1,176	4,034	195,212	18,960	5	223,294	895	881	791	906	895	656	324
GR-19A	8/31/93	24	24.1	21,497	1,177	5,998	194,059	21,234	5	223,020	894	881	795	906	904	662	327
GR-25H2	9/1/93	19	26.7	17,511	1,047	5,984	158,683	20,090	4	182,160	890	881	774	893	823	623	304
GR-1A	9/2/93	35	11.8	33,428	766	5,968	302,290	16,056	4	314,036	896	881	824	945	940	695	342
GR-5D2	9/2/93	34	25.0	28,342	1,596	5,974	261,032	22,489	4	301,426	900	879	820	938	934	692	347
GR-5C2	9/2/93	33	25.4	27,712	1,624	5,980	272,739	23,711	6	300,256	894	881	837	941	912	680	334
GR-6D2	9/2/93	33	25.3	27,833	1,628	5,020	273,841	23,699	4	289,893	896	881	835	940	923	683	335
GR-25A	9/3/93	20	23.8	18,819	1,000	5,080	178,010	16,490	5	185,007	890	881	788	898	800	612	300
GR-26B2	9/3/93	19	25.6	16,907	1,001	6,132	171,208	14,610	7	170,190	895	881	797	893	796	610	300
GR-26I2	9/7/93	18	25.8	17,668	1,068	5,908	160,038	19,378	4	181,161	894	881	776	893	824	620	300
GR-25J	9/7/93	19	25.0	17,878	1,059	5,870	161,808	22,328	4	182,600	894	881	777	893	831	622	300
GR-H2	9/7/93	20	25.0	17,813	1,060	5,937	161,621	17,127	4	182,340	901	881	781	894	827	620	300
GR-27B	9/8/93	19	22.9	17,898	914	5,941	150,201	17,029	5	177,252	894	881	775	892	797	608	300
GR-27C	9/8/93	19	23.0	17,703	916	5,898	164,833	18,040	5	170,809	894	881	774	891	801	608	300
GR-27D	9/8/93	19	22.9	17,920	917	5,860	160,072	20,798	5	177,507	884	881	776	892	804	611	300
GR-27E	9/8/93	19	23.0	17,768	918	5,989	166,062	23,286	5	177,042	894	881	775	891	806	613	300
GR-28A	9/8/93	18	18.7	18,404	703	5,983	161,291	18,374	6	178,843	890	881	774	891	805	612	300
GR-28B	9/8/93	19	18.0	18,806	716	5,883	184,860	17,864	5	177,719	897	881	772	891	800	611	300
GR-18A	8/30/93	23	20.0	20,039	1,249	5,938	177,704	20,454	6	212,078	892	881	785	901	857	639	311
GR	10/25/93	26	18.5	23,367	918	5,430	210,486	17,278	6	225,810	886	883	778	907	881	653	318
GR 113B	10/26/93	24	24.0	21,776	1,223	5,830	190,661	21,400	6	223,017	890	883	802	910	851	640	313
GR 113A	10/26/93	25	24.0	21,778	1,228	5,804	189,240	22,749	6	223,303	885	883	796	909	868	646	316
GR 113C	10/26/93	26	25.0	21,370	1,228	5,830	188,840	18,870	6	223,204	890	883	803	909	870	651	318
GR 111A	10/26/93	26	20.0	21,476	1,289	5,878	182,523	18,682	6	223,079	890	883	801	910	884	654	319
GR 111B	10/26/93	25	20.1	22,662	900	5,936	204,722	16,182	6	223,758	886	883	799	910	886	656	320
GR 101B	10/27/93	34	24.7	28,828	1,631	5,900	261,016	27,347	7	304,190	885	883	826	942	930	690	330
GR 101C	10/27/93	34	24.9	28,714	1,641	5,993	267,454	26,006	7	303,856	885	883	831	943	947	697	341
GR 101D	10/27/93	34	24.8	28,670	1,641	5,976	271,480	25,164	7	303,810	886	884	831	943	960	704	344
GR 101A	10/27/93	34	24.7	28,933	1,630	5,890	261,137	29,980	7	304,051	884	883	819	940	969	702	345
GR 104A	10/27/93	34	24.9	28,649	1,641	4,873	266,876	26,360	7	303,970	887	884	822	941	970	702	344
GR 104B	10/27/93	34	24.8	28,652	1,642	3,990	266,778	26,346	7	303,809	885	884	822	940	973	703	345
GR 104C	10/27/93	34	24.9	28,698	1,642	2,980	267,328	26,320	7	303,828	885	883	819	940	967	702	344
GR 102A	10/28/93	33	23.7	29,008	1,551	0,000	268,729	25,590	7	297,422	889	884	842	944	889	668	336
GR 102B	10/28/93	33	20.1	28,908	1,293	5,877	278,616	22,110	7	297,820	886	883	842	944	801	670	330
GR 102C	10/28/93	33	15.1	31,673	974	5,889	283,310	17,716	7	298,520	885	883	839	942	904	675	332
GR 103A	10/28/93	33	25.0	28,268	1,676	5,861	261,592	23,614	7	297,971	880	883	840	943	923	681	335
GR 103B	10/28/93	33	25.7	28,208	1,606	5,961	261,797	29,799	7	298,709	880	883	837	942	937	690	339

TABLE C-4. GR OPERATING CONDITIONS (continued)

Test I. D.	Test Date	Gross Power (MWe)	Gas Heat (%)	Coal Flow (lb/hr)	Reb Gas (scfm)	FGR (scfm)	Cyclone Air (lb/hr)	OFA Flow (scfm)	Opac (%)	Steam Load (lb/hr)	SSH Steam (F)	SSH Steam (psig)	PSH Steam (F)	Blr Drum (psig)	BlrBnk G I (F)	BlrBnk G O (F)	AirHtr G O (F)
GR 112A2	10/28/93	24	21.4	21,817	1,024	6,000	202,661	18,828	7	216,817	888	884	786	907	933	683	326
GR 112A	10/28/93	24	24.1	21,200	1,160	6,000	198,830	18,897	7	216,731	885	884	795	907	939	685	328
GR 112B	10/29/93	24	20.4	21,804	867	6,000	203,333	16,674	7	216,516	887	884	795	907	938	685	328
GR 112C	10/29/93	24	14.9	23,365	704	5,935	216,978	13,342	7	216,801	886	884	793	907	937	686	328
GR-106A	11/10/93	32	26.0	20,978	1,667	5,899	248,531	25,088	7	171,613	885	871	786	881	793	624	334
GR-106B	11/10/93	32	26.0	20,849	1,668	5,804	247,973	20,122	7	210,074	898	880	822	904	858	671	347
GR-107C	11/10/93	32	26.1	20,788	1,668	3,100	248,710	20,166	6	288,208	888	881	817	937	918	738	381
GR-107B	11/10/93	32	26.1	20,883	1,670	3,898	247,392	20,123	7	171,161	885	871	789	882	794	628	340
GR-106C	11/10/93	37	26.3	20,782	1,678	5,870	247,280	30,729	7	282,663	887	881	836	933	930	725	381
GR-108A	11/10/93	37	23.8	20,278	1,582	5,819	284,486	20,844	7	210,778	886	871	805	894	855	674	366
GR-108B	11/10/93	37	26.0	20,848	1,888	5,884	247,873	20,127	7	208,707	886	871	789	893	841	684	363
GR-107C	11/10/93	32	26.1	20,788	1,888	3,100	248,710	20,166	6	288,138	888	881	818	938	916	731	388
GR-107B	11/10/93	32	25.1	20,883	1,670	3,888	247,392	20,173	4	296,858	885	881	818	938	919	735	395
GR-106C	11/10/93	32	25.3	20,782	1,678	5,870	247,280	30,729	7	209,840	886	871	807	894	853	667	364
GR	11/15/93	26	23.0	22,160	1,141	5,864	200,722	18,596	6	179,482	868	891	741	900	841	667	356
GR	11/16/93	23	22.0	22,748	1,107	5,909	205,528	19,440	0			898	695	903			
GR 114 A	11/17/93	23	23.0	22,212	1,144	5,004	200,801	18,401	5	302,556	893	889	808	945	909	709	369
GR 114 B	11/17/93	23	23.2	22,000	1,148	4,050	198,220	18,423	7	205,813	896	881	817	903	840	657	344
GR 114 C	11/17/93	23	23.1	22,106	1,140	2,938	200,032	18,412	5	300,675	891	891	814	946	919	750	395
GR	11/23/93	23	22.2	22,621	1,113	5,915	203,367	18,536	7	206,601	896	881	814	903	858	677	360
GR	2/16/94	26	21.4	27,369	1,291	5,963	247,813	22,201	7	207,180	887	871	800	893	860	672	361
GR	2/17/94	26	22.2	26,707	1,270	5,948	231,846	20,229	6	178,030	899	881	788	892	888	651	350
GR	2/18/94	28	21.2	26,968	1,248	5,967	242,787	19,020	6	295,749	901	881	801	932	940	766	414
GR	3/20/94	30	22.2	20,802	1,409	5,618	282,048	21,607	4	268,092	894	881	847	928	886	656	327
GR	4/6/94	31	20.1	20,237	1,243	6,000	260,116	18,908	4	260,989	895	887	839	925	868	651	321
GR-25-25	4/8/94	26	23.8	21,418	1,161	5,976	184,300	18,721	4	204,949	891	881	816	903	832	647	339
GR-25-25	4/8/94	25	23.1	21,685	1,123	5,894	198,948	18,786	3	205,653	890	881	816	903	828	626	314
GR-25-30	4/8/94	29	14.3	27,614	837	5,059	253,700	18,490	3	240,654	898	882	827	916	880	655	327
GR-23-25	4/9/94	28	22.1	18,407	801	5,993	173,542	19,401	3	169,545	903	880	787	891	822	626	312
GR-23-23	4/9/94	24	23.1	20,638	1,063	5,909	189,944	18,016	3	194,220	892	881	800	898	859	641	320
GR-23-28	4/9/94	29	23.4	25,046	1,321	5,901	226,113	23,310	3	241,190	891	882	829	916	898	660	333
GR-23-30	4/11/94	30	23.0	26,796	1,377	5,949	242,747	22,657	4	255,784	891	881	834	922	928	681	339
GR-23-26	4/11/94	26	23.7	22,757	1,216	6,000	206,133	21,209	4	214,139	903	881	820	906	848	642	319
GR-23-25	4/12/94	26	23.6	22,993	1,224	5,907	207,817	21,204	12	216,329	891	881	824	907	858	647	323
GR-23-30	4/12/94	30	21.4	27,609	1,307	5,691	250,383	21,270	1	255,629	890	881	834	922	898	669	335
GR	4/14/94	27	22.6	23,164	1,160	5,980	210,220	17,936	3	225,574	892	881	814	910	875	650	328
GR-23-24	4/20/94	25	23.4	21,087	1,113	5,972	181,634	17,211	5	209,014	893	881	788	901	881	652	327
GR-23-30	4/21/94	30	23.6	25,834	1,300	5,907	234,455	22,270	5	265,300	891	881	823	923	877	652	327
GR	5/17/94	25	22.5	22,633	1,177	5,840	203,314	17,476	4	216,029	888	879	828	904	823	628	320
GR	5/18/94	25	22.7	22,033	1,112	5,808	189,626	18,307	4	220,273	889	880	823	906	892	654	321

TABLE C-5. GR THERMAL IMPACTS

Test I. D.	Test Date	Gross Power (MWe)	Gas Heat (%)	TotStm H A (MBtu/hr)	Furn H A (MBtu/hr)	SSH H A (MBtu/hr)	PSH H A (MBtu/hr)	GenBnk H A (MBtu/hr)	Attemp H A (MBtu/hr)	AirHt H A (MBtu/hr)	Furn H A Ratio	SSH H A Ratio	PSH H A Ratio	GenBnk H A Ratio	DimAtt H A Ratio	AirHtr H A Ratio	Boiler Effic. (%)
GR-6B	7/28/93	33	23.4	342.8	203.7	40.1	71.8	27.0	28.8	38.8	0.96	1.00	1.06	0.88	1.33	1.02	84.59
GR-5C	7/28/93	33	23.4	342.6	203.3	38.8	72.0	27.3	29.2	38.7	0.98	1.00	1.07	0.89	1.35	1.02	84.56
GR-5A	7/29/93	35	23.2	345.4	203.9	40.0	72.6	28.3	29.2	39.8	0.95	1.07	1.06	1.01	1.33	1.03	84.50
GR-4A	7/29/93	35	21.8	346.4	202.8	40.1	73.5	28.8	30.2	40.0	0.95	1.05	1.08	1.02	1.37	1.04	84.48
GR-3A	7/30/93	34	19.6	339.4	202.2	41.2	68.5	26.8	29.0	38.5	0.96	1.11	1.04	0.97	1.37	1.03	84.00
GR-2A	7/30/93	34	16.1	340.1	207.4	40.1	71.2	27.3	27.8	39.7	0.97	1.05	1.04	0.97	1.25	1.02	84.91
GR-5D	7/30/93	35	23.1	347.6	207.9	39.0	71.7	29.0	26.8	40.6	0.97	1.01	1.04	1.02	1.20	1.04	84.52
GR-5E	7/30/93	34	22.8	360.6	211.1	38.7	71.5	28.2	26.6	40.8	0.97	1.02	1.03	0.98	1.17	1.05	84.51
GR-5F	7/30/93	34	22.6	340.8	211.5	39.8	70.5	26.8	28.1	39.9	0.98	1.03	1.02	0.94	1.16	1.03	84.73
GR-5G	7/30/93	35	22.8	350.9	209.7	39.8	72.3	28.9	27.3	40.3	0.97	1.02	1.04	1.01	1.20	1.02	84.63
GR-15B	8/2/93	20	22.6	277.3	168.7	31.0	64.6	22.1	19.7	32.2	0.95	1.10	1.08	1.09	1.46	1.09	84.59
GR-16A	8/2/93	26	22.8	278.0	170.0	31.0	64.2	22.2	19.5	31.8	0.96	1.08	1.05	1.08	1.43	1.07	84.83
GR-16C	8/2/93	20	22.6	277.8	168.4	30.2	64.4	23.8	18.1	33.1	0.95	1.08	1.05	1.10	1.40	1.11	84.42
GR-14A	8/2/93	20	26.0	280.1	170.4	31.0	56.1	23.8	18.6	32.1	0.96	1.08	1.08	1.14	1.41	1.07	84.45
GR-13A	8/2/93	26	20.6	278.6	170.2	28.8	64.4	24.0	18.7	33.1	0.95	1.05	1.05	1.17	1.36	1.11	84.46
GR-12A	8/2/93	26	19.6	277.2	168.9	28.8	64.3	24.3	18.5	33.2	0.95	1.05	1.06	1.19	1.37	1.12	84.42
GR-11A	8/2/93	26	16.5	277.1	169.8	29.2	63.6	24.8	17.0	32.8	0.95	1.03	1.04	1.21	1.26	1.11	84.61
GR-25A	8/11/93	19	23.8	226.5	0.0	21.2	39.1	0.0	8.6	0.0	0.00	1.03	1.02	0.00	1.23	0.00	84.82
GR-25B	8/11/93	19	23.9	226.6	0.0	21.2	39.6	0.0	8.7	0.0	0.00	1.02	1.03	0.00	1.23	0.00	84.50
GR-25C	8/11/93	20	24.0	223.3	0.0	21.1	39.2	0.0	8.8	0.0	0.00	1.03	1.03	0.00	1.30	0.00	84.54
GR-24A	8/11/93	19	22.2	218.7	0.0	20.6	38.3	0.0	8.4	0.0	0.00	1.03	1.03	0.00	1.33	0.00	84.60
GR-22A	8/11/93	19	17.0	218.8	0.0	20.2	37.8	0.0	8.1	0.0	0.00	1.03	1.04	0.00	1.35	0.00	84.50
GR-16D	8/12/93	27	23.2	280.7	0.0	28.0	60.6	0.0	12.1	0.0	0.00	0.88	0.87	0.00	0.87	0.00	84.30
GR-15E	8/12/93	27	23.1	281.1	0.0	28.4	61.3	0.0	13.2	0.0	0.00	0.88	0.98	0.00	0.94	0.00	84.34
GR-15F	8/12/93	27	23.3	281.0	0.0	29.1	62.1	0.0	14.4	0.0	0.00	1.01	0.99	0.00	1.03	0.00	84.31
GR-5A2	8/13/93	33	24.8	337.5	0.0	37.5	69.1	0.0	26.6	0.0	0.00	1.02	1.04	0.00	1.21	0.00	84.30
GR-8A	8/13/93	34	24.8	338.3	0.0	38.0	70.8	0.0	28.7	0.0	0.00	1.05	1.07	0.00	1.33	0.00	84.10
GR-5H	8/13/93	33	24.9	337.8	0.0	38.2	70.5	0.0	27.6	0.0	0.00	1.03	1.06	0.00	1.31	0.00	83.87
GR-5I	8/13/93	32	24.9	338.0	0.0	38.6	70.7	0.0	26.2	0.0	0.00	0.99	1.06	0.00	1.24	0.00	83.65
GR-15G	8/17/93	25	21.4	275.2	0.0	31.3	64.6	0.0	20.6	0.0	0.00	1.12	1.08	0.00	1.57	0.00	84.65
GR-15G2	8/17/93	25	23.6	276.0	0.0	30.3	64.3	0.0	19.7	0.0	0.00	1.08	1.07	0.00	1.40	0.00	84.49
GR-15H	8/17/93	25	23.6	276.6	0.0	29.2	64.4	0.0	19.0	0.0	0.00	1.04	1.07	0.00	1.43	0.00	84.11
GR-15I	8/17/93	25	23.5	276.8	0.0	28.6	64.6	0.0	18.4	0.0	0.00	1.02	1.07	0.00	1.38	0.00	83.89
GR-8B	8/18/93	33	24.8	345.3	0.0	41.3	73.7	0.0	31.4	0.0	0.00	1.09	1.08	0.00	1.43	0.00	84.15
GR-5I	8/18/93	33	24.8	346.3	0.0	39.7	74.1	0.0	30.9	0.0	0.00	1.04	1.08	0.00	1.39	0.00	83.69
GR-25D	8/19/93	19	22.2	219.5	0.0	21.2	40.2	0.0	10.8	0.0	0.00	1.06	1.08	0.00	1.72	0.00	84.49
GR-25E	8/19/93	19	22.2	220.0	0.0	20.6	40.5	0.0	10.7	0.0	0.00	1.03	1.09	0.00	1.67	0.00	84.44
GR-25E2	8/19/93	19	21.9	221.6	0.0	20.8	39.0	0.0	8.5	0.0	0.00	1.03	1.04	0.00	1.30	0.00	85.02
GR-25F	8/19/93	19	22.0	221.1	0.0	21.1	38.2	0.0	9.4	0.0	0.00	1.04	1.05	0.00	1.45	0.00	84.96
GR-25G	8/20/93	19	22.7	222.1	0.0	21.2	40.5	0.0	10.6	0.0	0.00	1.04	1.07	0.00	1.59	0.00	84.94
GR-25G2	8/20/93	19	25.5	221.1	0.0	21.6	40.8	0.0	11.3	0.0	0.00	1.07	1.09	0.00	1.73	0.00	84.94
GR-25H	8/20/93	19	25.6	222.1	0.0	20.8	41.1	0.0	11.1	0.0	0.00	1.02	1.08	0.00	1.66	0.00	84.42
GR-25I	8/20/93	19	25.7	221.3	0.0	21.2	40.9	0.0	11.1	0.0	0.00	1.05	1.09	0.00	1.69	0.00	84.60
GR-25F2	8/20/93	19	25.9	219.1	0.0	21.0	40.7	0.0	11.4	0.0	0.00	1.06	1.10	0.00	1.80	0.00	84.57
GR-25E3	8/20/93	19	25.8	220.4	0.0	21.2	40.4	0.0	10.9	0.0	0.00	1.05	1.08	0.00	1.69	0.00	84.59
GR-25D2	8/20/93	19	25.3	227.1	24.9	22.8	41.4	7.5	12.1	7.8	0.17	1.08	1.07	0.18	1.68	0.13	84.52

Note: H A Ratio relative to baseline case

TABLE C-5. GR THERMAL IMPACTS (continued)

Test I.D.	Test Date	Gross Power (MWe)	Gas Heat (%)	TotStm H A (MBtu/hr)	Furn H A (MBtu/hr)	SSH H A (MBtu/hr)	PSH H A (MBtu/hr)	GenBnk H A (MBtu/hr)	Attmp H A (MBtu/hr)	AirHt H A (MBtu/hr)	Furn H A Ratio	SSH H A Ratio	PSH H A Ratio	GenBnk H A Ratio	DnnAH H A Ratio	AirHtr H A Ratio	Boiler Effic. (%)
GR-14A2	8/23/93	24	24.4	265.9	168.7	28.2	49.1	19.9	15.1	29.2	0.98	1.06	1.01	1.05	1.25	1.06	84.68
GR-15A2	8/23/93	24	23.2	268.6	170.6	27.9	48.3	20.8	14.5	29.6	0.98	1.04	1.00	1.00	1.17	1.07	84.61
GR-5E2	8/23/93	31	25.2	339.4	200.8	30.8	69.0	30.9	26.1	39.2	0.95	1.04	1.04	1.13	1.23	1.07	83.97
GR-14A2	8/31/93	24	25.0	256.9	163.7	25.5	46.7	21.1	11.9	30.1	0.97	1.00	1.01	1.17	1.08	1.10	84.39
GR-15F2	8/31/93	24	24.1	256.2	162.6	25.7	46.7	21.1	12.1	29.8	0.97	1.02	1.01	1.18	1.11	1.10	84.42
GR-15C2	8/31/93	24	24.0	255.9	162.8	25.4	46.2	21.5	11.5	29.9	0.97	1.01	1.00	1.20	1.06	1.10	84.43
GR-19A	8/31/93	24	24.1	255.4	160.9	24.9	46.7	22.9	11.8	31.1	0.96	0.99	1.01	1.28	1.09	1.15	84.16
GR-25H2	9/1/93	19	25.7	214.9	144.3	17.8	36.3	16.3	5.1	26.1	0.98	0.92	1.00	1.21	0.87	1.22	84.36
GR-1A	9/2/93	35	11.6	350.4	209.6	39.6	71.5	29.8	26.0	41.7	0.97	1.02	1.03	1.04	1.14	1.05	84.63
GR-5G2	9/2/93	34	25.0	345.4	206.6	40.9	69.7	28.8	26.0	40.5	0.97	1.08	1.02	1.03	1.18	1.06	84.24
GR-5C2	9/2/93	33	25.4	337.2	199.3	30.8	70.8	28.3	20.4	41.7	0.95	1.05	1.07	1.04	1.35	1.10	84.12
GR-5D2	9/2/93	33	25.3	337.0	199.3	38.2	70.5	29.1	27.2	41.9	0.95	1.03	1.06	1.07	1.29	1.11	84.08
GR-25A	9/3/93	20	23.6	217.4	141.4	21.3	39.4	15.3	10.2	26.4	0.96	1.08	1.07	1.12	1.67	1.21	84.66
GR-25B2	9/3/93	19	25.5	210.0	137.9	20.0	37.8	14.3	9.5	24.7	0.96	1.07	1.08	1.11	1.81	1.20	84.51
GR-25I2	9/7/93	19	25.8	222.8	149.5	19.0	37.7	16.6	5.5	26.5	1.00	0.93	1.00	1.17	0.83	1.24	84.53
GR-25J	9/7/93	19	25.6	225.1	150.3	18.6	38.3	17.8	5.2	28.0	0.99	0.90	1.00	1.23	0.75	1.31	84.27
GR-H2	9/7/93	20	25.6	219.2	145.7	19.5	37.6	16.4	6.1	25.5	0.98	0.98	1.02	1.19	0.98	1.19	84.76
GR-27B	9/8/93	19	22.9	210.2	142.0	18.1	35.5	14.6	5.4	24.6	0.98	0.96	1.01	1.13	1.02	1.19	84.79
GR-27C	9/8/93	19	23.0	210.1	142.2	17.3	35.4	15.2	4.5	25.4	0.99	0.92	1.01	1.18	0.85	1.23	84.60
GR-27D	9/8/93	19	22.9	210.8	142.3	17.1	35.7	15.7	4.4	26.3	0.99	0.91	1.01	1.21	0.82	1.27	84.43
GR-27E	9/8/93	19	23.0	210.6	142.6	16.3	35.8	16.2	3.6	27.4	0.99	0.86	1.01	1.25	0.67	1.32	84.10
GR-28A	9/8/93	19	19.7	210.8	142.6	17.1	35.5	15.7	3.8	26.2	0.99	0.91	1.01	1.22	0.71	1.27	84.52
GR-28B	9/8/93	19	18.0	211.8	143.6	17.4	35.4	15.2	4.0	25.9	0.99	0.92	1.00	1.17	0.74	1.24	84.00
GR-18A	9/30/93	23	26.0	233.1	150.4	18.9	41.3	21.6	7.1	32.7	0.96	0.90	1.01	1.30	0.86	1.28	84.07
GR	10/25/93	25	18.5	277.9	182.1	26.1	48.7	21.5	10.1	31.5	1.02	0.92	0.94	1.06	0.75	1.15	84.75
GR 113B	10/26/93	24	24.6	266.4	188.6	26.8	49.8	20.2	15.2	31.4	0.98	1.00	1.02	1.05	1.24	1.16	84.51
GR 113A	10/26/93	25	24.6	263.5	188.3	25.6	48.6	21.1	13.3	31.4	0.98	0.97	1.01	1.12	1.11	1.16	84.47
GR113C	10/26/93	25	25.0	263.9	166.1	27.0	49.5	21.3	15.1	31.0	0.97	1.02	1.03	1.13	1.27	1.14	84.41
GR 111A	10/26/93	25	26.0	264.0	166.3	27.0	49.4	21.3	15.3	30.4	0.97	1.02	1.02	1.13	1.28	1.12	84.55
GR 111B	10/26/93	25	20.1	263.7	166.5	27.2	48.9	21.1	15.2	30.1	0.97	1.03	1.02	1.11	1.27	1.10	84.69
GR 101B	10/27/93	34	24.7	345.4	205.4	38.5	70.9	30.7	27.3	43.0	0.96	1.00	1.03	1.09	1.73	1.12	84.13
GR 101C	10/27/93	34	24.9	344.9	203.6	38.7	71.6	30.9	28.4	43.3	0.95	1.01	1.05	1.10	1.28	1.13	84.01
GR 101D	10/27/93	34	24.9	344.8	202.7	38.4	71.8	31.9	28.1	43.5	0.95	1.00	1.05	1.14	1.27	1.13	83.93
GR 101A	10/27/93	34	24.7	345.0	206.4	35.5	69.6	33.4	23.3	43.6	0.96	0.93	1.01	1.18	1.05	1.14	83.95
GR 104A	10/27/93	34	24.9	345.4	205.6	36.6	70.1	33.0	24.4	43.5	0.96	0.96	1.02	1.17	1.10	1.14	83.92
GR 104B	10/27/93	34	24.9	344.9	206.1	35.8	70.0	33.0	23.9	43.5	0.96	0.94	1.02	1.17	1.08	1.13	83.92
GR 104C	10/27/93	34	24.9	344.5	208.0	35.2	69.3	32.0	22.6	43.6	0.97	0.92	1.01	1.14	1.02	1.14	83.93
GR 102A	10/28/93	33	23.7	354.6	208.3	43.6	75.4	27.3	34.4	42.6	0.95	1.11	1.07	0.94	1.49	1.14	84.17
GR 102B	10/28/93	33	20.1	351.1	206.2	42.7	74.9	27.8	33.7	41.4	0.95	1.08	1.07	0.97	1.48	1.10	84.49
GR 102C	10/28/93	33	15.1	350.3	207.3	41.3	74.2	27.5	32.4	41.3	0.96	1.06	1.06	0.96	1.42	1.10	84.65
GR 103A	10/28/93	33	25.6	350.5	205.8	41.3	74.5	28.9	32.4	40.9	0.95	1.06	1.07	1.01	1.43	1.09	84.37
GR 103B	10/28/93	33	25.7	350.6	205.9	39.3	74.1	31.3	30.9	44.2	0.95	1.01	1.06	1.09	1.35	1.17	83.86

Note: H A Ratio relative to baseline case

TABLE C-5. GR THERMAL IMPACTS (continued)

Test I.D.	Test Date	Gross Power (MWe)	Gas Heat (%)	TotStm HA (MBtu/hr)	Furn HA (MBtu/hr)	SSH HA (MBtu/hr)	PSH HA (MBtu/hr)	GenBnk HA (MBtu/hr)	Attmp HA (MBtu/hr)	AirHtr HA (MBtu/hr)	Furn HA Ratio	SSH HA Ratio	PSH HA Ratio	GenBnk HA Ratio	DrmAtt HA Ratio	AirHtr HA Ratio	Boiler Effic. (%)
GR 117A2	10/28/93	24	21.4	258.6	160.7	25.8	47.2	23.0	13.6	31.2	0.96	1.01	1.02	1.27	1.22	1.19	84.37
GR 112A	10/29/93	24	24.1	260.4	160.3	25.6	47.0	23.6	13.6	31.6	0.95	1.00	1.01	1.30	1.22	1.20	84.19
GR 112B	10/29/93	24	20.4	256.3	160.2	25.9	46.9	23.3	13.6	31.2	0.95	1.02	1.01	1.29	1.23	1.19	84.30
GR 112C	10/29/93	24	14.9	256.1	160.6	25.9	46.6	23.1	13.5	31.2	0.96	1.02	1.01	1.28	1.23	1.19	84.50
GR-106A	11/10/93	32	25.0	232.0	168.8	20.6	38.9	12.6	9.6	26.6	1.07	1.01	1.03	0.90	1.42	1.33	84.42
GR-106B	11/10/93	32	25.0	289.8	188.6	30.0	54.1	19.1	19.2	31.2	1.06	1.00	1.07	0.96	1.46	1.23	83.46
GR-107C	11/10/93	32	25.1	350.8	217.5	39.6	70.1	23.7	26.5	45.3	1.00	1.02	1.01	0.83	1.16	1.21	82.32
GR--107B	11/10/93	32	25.1	233.3	161.0	20.3	39.4	12.6	9.4	26.8	1.07	0.99	1.04	0.89	1.38	1.34	84.14
GR-106C	11/10/93	32	25.3	356.6	219.0	41.0	70.7	25.8	29.9	41.8	1.04	1.11	1.07	0.95	1.42	1.18	83.06
GR-108A	11/10/93	32	23.6	289.3	191.8	28.7	61.8	18.8	17.3	33.1	1.08	1.03	1.02	0.84	1.30	1.30	83.72
GR-106B	11/10/93	32	25.0	287.8	192.2	28.8	60.8	18.4	16.4	32.1	1.09	1.03	1.01	0.82	1.25	1.27	84.25
GR-107C	11/10/93	32	25.1	348.5	216.1	40.4	69.4	22.7	27.2	41.3	1.00	1.05	1.01	0.80	1.21	1.11	82.83
GR--107B	11/10/93	32	26.1	347.8	214.9	40.9	69.4	22.0	28.0	41.2	1.00	1.06	1.01	0.80	1.25	1.11	82.74
GR-106C	11/10/93	32	25.3	288.9	180.4	29.4	52.0	17.0	18.2	32.6	1.08	1.06	1.03	0.85	1.38	1.29	83.87
GR	11/15/93	26	23.0	216.8	162.6	17.0	33.0	13.4	2.7	26.7	1.03	0.86	0.89	0.98	0.43	1.27	83.61
GR	11/16/93	23	22.0	278.6	188.1	28.6	61.8	18.2	17.7	31.1	1.05	1.08	1.07	1.02	1.47	1.23	83.29
GR 114 A	11/17/93	23	23.0	366.9	232.3	39.5	71.0	24.1	22.7	43.9	1.04	0.97	0.97	0.80	0.93	1.15	84.08
GR 114 B	11/17/93	23	23.2	272.7	177.0	27.7	50.3	17.7	17.2	28.0	1.05	1.08	1.07	0.97	1.53	1.13	83.69
GR 114 C	11/17/93	23	23.1	340.9	221.4	38.0	69.0	20.6	23.4	45.1	1.03	0.88	1.00	0.73	1.04	1.19	83.38
GR	11/23/93	23	22.2	272.9	177.1	27.2	49.8	18.8	16.3	31.2	1.05	1.06	1.06	1.03	1.44	1.26	82.82
GR	2/16/94	26	21.4	272.1	179.9	27.3	48.1	16.9	15.7	37.2	1.06	1.06	1.03	0.92	1.39	1.29	83.88
GR	2/17/94	28	22.2	223.8	163.8	18.8	38.2	11.7	6.4	28.8	1.03	0.97	1.01	0.83	0.96	1.29	83.97
GR	2/18/94	28	21.2	339.6	219.2	35.4	64.4	20.5	17.3	44.3	1.04	0.86	0.97	0.75	0.82	1.19	82.97
GR	3/20/94	30	22.2	328.6	188.6	36.7	67.0	27.3	20.7	36.0	1.01	1.09	1.11	1.12	1.59	1.08	84.41
GR	4/6/94	31	20.1	323.5	200.5	33.9	64.2	24.9	24.7	34.3	1.03	1.04	1.09	1.05	1.43	1.06	84.64
GR-25-25	4/8/94	25	23.8	260.8	169.0	26.1	48.0	17.6	16.6	26.6	1.03	1.08	1.08	1.03	1.65	1.08	83.64
GR-25-25	4/8/94	25	23.1	271.6	176.8	26.4	50.0	19.2	16.6	26.4	1.04	1.03	1.07	1.05	1.49	1.07	84.36
GR-25-30	4/8/94	29	14.3	306.0	191.9	29.8	58.7	25.5	19.3	33.1	1.04	0.98	1.08	1.17	1.25	1.12	84.15
GR-23-25	4/9/94	20	22.1	234.3	168.8	17.8	40.2	17.4	6.0	24.3	1.06	0.88	1.06	1.23	0.89	1.24	83.61
GR-23-23	4/9/94	24	23.1	260.2	170.1	23.0	46.6	20.5	12.3	26.4	1.04	0.96	1.06	1.21	1.25	1.14	83.92
GR-23-29	4/9/94	29	23.4	308.8	182.8	30.8	59.7	26.4	21.1	32.9	1.03	1.00	1.07	1.19	1.34	1.11	83.86
GR-23-30	4/11/94	30	23.0	325.9	199.2	34.1	63.8	20.7	24.7	35.9	1.02	1.04	1.08	1.20	1.41	1.13	83.90
GR-23-26	4/11/94	26	23.7	269.6	171.1	26.3	51.1	21.1	16.4	29.0	1.02	1.04	1.11	1.17	1.51	1.12	84.09
GR-23-25	4/12/94	26	23.6	272.1	172.5	26.6	61.4	21.7	17.6	29.5	1.02	1.03	1.09	1.18	1.55	1.13	84.02
GR-23-30	4/12/94	30	21.4	314.4	193.1	33.0	61.7	26.5	24.0	35.2	1.02	1.05	1.08	1.16	1.47	1.11	84.11
GR	4/14/94	27	22.6	274.0	171.0	27.1	52.2	22.7	17.0	29.0	0.99	1.01	1.06	1.19	1.33	1.05	84.10
GR-23-24	4/20/94	25	23.4	261.2	169.6	23.8	46.5	21.4	9.7	26.4	1.00	0.92	0.99	1.16	0.85	1.05	84.04
GR-23-30	4/21/94	30	23.6	305.5	187.7	31.2	61.3	25.3	20.1	33.3	0.97	0.96	1.05	1.07	1.17	1.01	84.21
GR	5/17/94	25	22.5	278.3	173.8	30.6	55.2	18.6	22.0	26.8	0.98	1.09	1.09	0.92	1.65	1.03	84.46
GR	5/18/94	25	22.7	268.9	165.4	28.2	52.9	22.5	19.2	28.0	0.96	1.05	1.08	1.18	1.56	1.05	84.35

Note: HA Ratio relative to baseline case

TABLE C-6. SI EMISSIONS SUMMARY

Test I. D.	Test Date	Test Duration (hr:min)	Gross Power (MWe)	Ca/S Molar Ratio	Coal SR	Reb SR	Burn-out SR	Exit SR	OFA (%)	CEMS O2 (%, dry)	Plant O2 (%, wet)	COc (ppm)	CO2c (%)	NOxc (ppm)	NOx (lb/MBtu)	SO2c (ppm)	SO2 (lb/MBtu)	SO2 Reduc. (%)	Ca Utiliz. (%)
SI-15	9/10/93	1:00	20	1.23	1.15	1.15	1.27	1.34	10	5.84	4.61	13	15.4	588	0.802	2,470	4.705	20.26	16.51
SI-17	9/10/93	1:00	20	2.34	1.15	1.15	1.27	1.34	9	5.61	4.33	12	15.4	603	0.822	2,083	3.972	32.67	13.97
SI-19	9/10/93	0:57	20	3.46	1.15	1.15	1.27	1.34	9	5.36	4.14	13	15.1	589	0.803	1,761	3.357	43.11	12.45
SI-2	9/13/93	0:08	33	2.05	1.16	1.16	1.24	1.31	6	3.99	2.96	13	15.3	704	0.960	1,967	3.767	36.15	17.64
SI-8	9/13/93	0:54	33	2.01	1.16	1.16	1.24	1.30	7	3.95	2.92	13	15.3	669	0.913	1,129	2.147	63.60	31.67
SI-2A	9/14/93	1:01	33	2.09	1.16	1.16	1.23	1.31	6	4.46	3.33	9	15.4	732	0.998	1,732	3.304	44.01	21.07
SI-8A	9/14/93	2:00	33	2.16	1.15	1.15	1.23	1.29	6	4.16	3.05	9	15.5	746	1.017	1,551	2.958	49.87	23.09
SI-14	9/17/93	1:00	20	1.95	1.15	1.15	1.27	1.40	9	6.01	4.34	17	15.2	590	0.804	2,193	4.181	29.14	14.98
SI-16	9/17/93	1:00	20	1.87	1.15	1.15	1.27	1.36	9	5.54	4.49	10	15.2	569	0.775	2,151	4.102	30.47	16.27
SI-26	9/20/93	1:00	24	1.93	1.15	1.15	1.26	1.35	8	5.01	3.89	14	15.4	586	0.797	2,126	4.043	31.48	16.31
SI-27	9/20/93	1:00	24	1.94	1.15	1.15	1.26	1.32	8	4.71	3.69	12	15.5	591	0.805	2,138	4.074	30.95	15.95
SI-28	9/22/93	1:00	33	2.27	1.14	1.14	1.22	1.30	7	3.96	3.19	16	15.3	681	0.929	1,716	3.276	44.48	19.61
SI-8B	9/22/93	0:57	33	2.15	1.15	1.15	1.23	1.28	7	3.68	3.01	13	15.2	697	0.950	1,693	3.229	45.27	21.03
SI-11B	9/22/93	1:00	34	2.15	1.15	1.15	1.23	1.26	7	3.31	2.79	13	15.2	689	0.939	1,761	3.357	43.10	20.08
SI-3	9/23/93	1:00	33	1.10	1.15	1.15	1.23	1.30	7	4.24	3.45	10	15.4	744	1.014	2,096	3.996	32.28	29.29
SI-6	9/23/93	1:00	33	2.10	1.15	1.15	1.23	1.29	6	4.04	3.20	12	15.4	750	1.022	1,553	2.965	49.75	23.66
SI-10	9/23/93	1:00	33	2.07	1.15	1.15	1.23	1.29	6	4.02	3.06	14	15.3	790	1.077	1,186	2.267	61.57	21.43
SI-27	11/2/93	0:57	23	1.75	1.14	1.14	1.25	1.29	8	4.96	4.04	10	15.2	624	0.851	2,057	3.923	33.51	19.19
SI-28	11/2/93	0:55	23	1.74	1.14	1.14	1.25	1.30	8	5.07	4.04	8	15.2	619	0.843	1,976	3.762	36.24	20.78
SI-29	11/2/93	0:57	23	1.77	1.14	1.14	1.25	1.31	8	5.25	4.10	7	15.3	649	0.885	1,907	3.644	38.24	21.58
SI-30	11/2/93	0:57	23	1.72	1.14	1.14	1.24	1.34	8	5.52	4.23	11	15.2	652	0.889	1,858	3.547	39.88	23.14
SI-16	11/3/93	0:30	19	1.64	1.14	1.14	1.27	1.33	10	5.56	4.51	11	15.1	622	0.848	2,173	4.139	29.84	18.17
SI-17	11/3/93	0:30	19	1.71	1.14	1.14	1.27	1.36	10	5.84	4.59	13	15.1	633	0.863	2,106	4.016	31.94	18.69
SI-18	11/3/93	0:35	19	1.56	1.14	1.14	1.27	1.38	10	6.26	4.79	12	14.9	613	0.835	2,114	4.030	31.70	20.26
SI-23	11/3/93	0:30	23	1.14	1.15	1.15	1.26	1.32	9	5.32	4.25	7	15.2	689	0.940	2,171	4.133	29.95	26.37
SI-24	11/3/93	0:35	23	2.24	1.15	1.15	1.26	1.33	9	5.21	4.17	11	15.1	664	0.903	1,622	3.108	47.32	21.15
SI-23-25	6/2/94	3:17	25	1.67	1.14	1.15	1.20	1.23	4	5.13	3.77	39	15.3	661	0.901	2,112	4.034	31.64	18.96
SI-25	6/3/94	6:12	26	1.79	1.15	1.15	1.19	1.23	4	5.18	3.71	39	15.2	640	0.872	1,858	3.541	39.98	22.33
SI-31	6/3/94	5:41	31	1.58	1.15	1.15	1.19	1.22	4	4.44	3.12	27	15.3	678	0.924	1,841	3.428	41.89	26.51

Notes: Subscript c denotes correction to 3% O2

SO2 reduction from 5.9 lb/MBtu baseline

TABLE C-7. SI OPERATING SUMMARY

Test I. D.	Test Date	Ca/S Molar Ratio	Sorb Flow (lb/hr)	Srb Inj AirFlow (scfm)	Coal Flow (lb/hr)	Cyclone Air (lb/hr)	OFA Flow (scfm)	Opac (%)	Steam Load (lb/hr)	SSH Steam (F)	SSH Steam (psig)	PSH Steam (F)	Blr Drum (psig)	BlrBnk G I (F)	BlrBnk G O (F)	AirHtr G O (F)
SI-15	9/10/93	1.23	1,848	2,425	23,075	209,292	4,984	6	180,514	879	881	750	891	833	651	329
SI-17	9/10/93	2.34	3,548	2,387	23,819	216,516	5,010	6	178,030	899	881	780	892	808	651	350
SI-19	9/10/93	3.46	5,290	2,365	23,761	215,667	4,989	6	178,081	897	881	768	892	841	666	357
SI-2	9/13/93	2.05	5,163	4,506	38,813	354,648	5,403	5	302,556	893	889	808	945	909	709	369
SI-8	9/13/93	2.01	4,972	3,482	38,405	351,112	5,482	4	302,349	891	891	798	944	924	746	400
SI-2A	9/14/93	2.09	5,233	4,528	39,144	356,255	5,381	5	300,675	891	891	814	946	919	750	395
SI-8A	9/14/93	2.16	5,357	3,787	38,811	352,896	5,276	5	301,309	893	891	797	944	946	760	411
SI-14	9/17/93	1.95	2,935	4,952	23,604	213,994	4,815	6	179,492	868	891	741	900	841	667	356
SI-16	9/17/93	1.87	2,851	3,516	23,726	215,322	4,873	5	177,421	892	891	774	902	805	641	354
SI-26	9/20/93	1.93	3,575	4,391	28,711	260,417	5,337	5	218,224	891	881	774	903	826	656	355
SI-27	9/20/93	1.94	3,575	3,039	28,616	259,585	5,340	5	218,697	892	881	778	904	825	661	365
SI-28	9/22/93	2.27	5,485	4,479	37,603	339,292	5,316	6	295,194	900	881	795	930	924	727	384
SI-8B	9/22/93	2.15	5,241	3,136	37,676	340,233	5,345	5	295,652	901	881	798	931	917	735	395
SI-11B	9/22/93	2.15	5,204	1,813	37,535	339,057	5,318	5	295,505	901	881	802	932	909	728	387
SI-3	9/23/93	1.10	2,816	3,588	37,916	344,836	5,384	6	295,721	900	881	807	932	891	699	369
SI-6	9/23/93	2.10	5,431	3,465	38,181	347,150	5,314	6	296,183	901	881	801	932	925	740	397
SI-10	9/23/93	2.87	7,457	3,383	38,096	346,571	5,333	6	295,749	901	881	801	932	940	766	414
SI-27	11/2/93	1.75	3,427	1,655	29,067	261,868	5,376	7	209,207	885	871	799	893	841	654	353
SI-28	11/2/93	1.74	3,517	2,444	29,079	261,670	5,315	7	208,851	887	871	803	893	840	659	356
SI-29	11/2/93	1.77	3,582	3,196	29,484	265,503	5,361	7	209,940	886	871	807	894	853	667	364
SI-30	11/2/93	1.72	3,500	4,526	29,554	266,124	5,317	7	210,776	885	871	805	894	855	674	365
SI-16	11/3/93	1.64	2,745	2,022	24,312	218,742	5,498	7	171,613	885	871	786	881	793	624	334
SI-17	11/3/93	1.71	2,836	3,168	24,203	218,220	5,510	7	171,161	885	871	789	882	794	628	340
SI-18	11/3/93	1.56	2,635	4,463	24,491	220,574	5,514	7	170,736	886	871	787	882	795	633	343
SI-23	11/3/93	1.14	2,201	2,825	28,323	255,812	5,536	7	206,769	887	871	795	892	833	653	345
SI-24	11/3/93	2.24	4,632	3,143	28,771	259,732	5,547	7	207,190	887	871	800	893	860	672	361
SI-23-25	6/2/94	1.67	3,498	1,593	30,726	277,040	2,703	4	204,642	888	881	832	903	860	652	359
SI-25	6/3/94	1.79	3,785	1,532	30,934	279,216	2,690	4	206,013	888	881	836	904	867	661	366
SI-31	6/3/94	1.58	3,997	1,440	36,927	333,626	3,051	4	252,332	889	880	849	922	914	693	380

TABLE C-8. SI HEAT TRANSFER SUMMARY

Test I. D.	Test Date	Gross Power (MWn)	Ca/S Molar Ratio	TotStm H A (MBtu/hr)	Furn H A (MBtu/hr)	SSH H A (MBtu/hr)	PSH H A (MBtu/hr)	GenBnk H A (MBtu/hr)	Attmp H A (MBtu/hr)	AirHt H A (MBtu/hr)	Furn H A Ratio	SSH H A Ratio	PSH H A Ratio	GenBnk H A Ratio	DmAtt H A Ratio	AirHtr H A Ratio	Boiler Effic. (%)
SI-15	9/10/93	20	1.23	214.3	150.9	16.6	33.7	13.2	2.3	25.7	1.03	0.85	0.93	0.98	0.38	1.21	84.52
SI-17	9/10/93	20	2.34	223.6	153.8	19.9	38.2	11.7	6.4	26.8	1.03	0.97	1.01	0.83	0.96	1.29	83.97
SI-19	9/10/93	20	3.46	220.4	151.1	19.8	36.5	13.0	5.4	26.7	1.02	0.99	0.98	0.95	0.82	1.28	83.84
SI-2	9/13/93	33	2.05	366.9	232.3	39.5	71.0	24.1	22.7	43.9	1.04	0.97	0.97	0.80	0.93	1.15	84.08
SI-8	9/13/93	33	2.01	363.8	236.4	37.6	68.7	21.1	19.3	44.4	1.06	0.93	0.95	0.71	0.80	1.16	83.32
SI-2A	9/14/93	33	2.09	348.9	221.4	38.0	69.0	20.6	23.4	45.1	1.03	0.98	1.00	0.73	1.04	1.19	83.38
SI-8A	9/14/93	33	2.16	346.3	221.5	37.3	65.3	22.2	19.5	45.0	1.03	0.98	0.95	0.79	0.88	1.18	83.05
SI-14	9/17/93	20	1.95	215.8	152.5	17.0	33.0	13.4	2.7	26.7	1.03	0.88	0.89	0.98	0.43	1.27	83.61
SI-16	9/17/93	20	1.87	219.8	151.0	19.5	37.0	12.3	6.3	26.0	1.02	0.97	0.99	0.89	0.97	1.25	83.76
SI-26	9/20/93	24	1.93	262.2	178.4	23.4	45.0	15.4	7.6	31.6	1.05	0.90	0.95	0.83	0.66	1.20	84.00
SI-27	9/20/93	24	1.94	260.4	176.6	24.1	45.1	14.5	8.7	31.4	1.04	0.94	0.96	0.79	0.76	1.19	83.88
SI-20	9/22/93	33	2.27	351.2	228.1	34.9	65.2	22.9	15.2	42.7	1.06	0.91	0.95	0.81	0.68	1.15	83.72
SI-8B	9/22/93	33	2.15	352.0	228.5	36.6	66.0	20.9	17.2	43.2	1.06	0.95	0.95	0.74	0.76	1.16	83.51
SI-11B	9/22/93	34	2.15	351.6	227.9	36.7	66.7	20.3	18.2	42.8	1.06	0.95	0.97	0.72	0.81	1.15	83.83
SI-3	9/23/93	33	1.10	339.7	216.5	35.4	65.5	22.3	18.5	42.4	1.03	0.96	0.99	0.82	0.88	1.14	84.09
SI-6	9/23/93	33	2.10	339.8	217.8	35.8	64.4	21.6	17.7	43.9	1.04	0.97	0.97	0.80	0.84	1.18	83.39
SI-10	9/23/93	33	2.87	339.5	219.2	35.4	64.4	20.5	17.3	44.3	1.04	0.96	0.97	0.75	0.82	1.19	82.97
SI-27	11/2/93	23	1.75	287.9	192.2	28.6	50.8	16.4	16.4	32.1	1.09	1.03	1.01	0.82	1.25	1.27	84.25
SI-28	11/2/93	23	1.74	289.3	192.6	29.2	51.5	16.0	17.2	32.0	1.09	1.05	1.02	0.80	1.31	1.27	84.13
SI-29	11/2/93	23	1.77	288.9	190.4	29.4	52.0	17.0	18.2	32.6	1.08	1.06	1.03	0.85	1.38	1.29	83.87
SI-30	11/2/93	23	1.72	289.3	191.8	28.7	51.9	16.8	17.3	33.1	1.08	1.03	1.02	0.84	1.30	1.30	83.72
SI-16	11/3/93	19	1.64	232.0	159.8	20.6	38.9	12.6	9.5	26.6	1.07	1.01	1.03	0.90	1.42	1.33	84.42
SI-17	11/3/93	19	1.71	233.3	161.0	20.3	39.4	12.6	9.4	26.8	1.07	0.99	1.04	0.89	1.38	1.34	84.14
SI-18	11/3/93	19	1.56	232.4	160.0	20.7	39.1	12.7	9.5	27.1	1.07	1.01	1.03	0.90	1.42	1.37	83.92
SI-23	11/3/93	23	1.14	269.3	180.4	26.2	46.9	15.8	14.1	31.4	1.07	1.03	1.01	0.88	1.27	1.26	84.33
SI-24	11/3/93	23	2.24	272.1	179.9	27.3	48.1	16.9	15.7	32.2	1.06	1.06	1.03	0.92	1.39	1.29	83.88
SI-23-25	6/2/94	25	1.67	284.8	183.4	30.1	52.6	18.7	22.5	29.0	1.08	1.17	1.11	1.02	1.93	1.18	84.34
SI-25	6/3/94	26	1.79	287.2	184.3	30.7	53.5	18.7	23.6	29.7	1.08	1.17	1.12	1.01	1.94	1.20	84.19
SI-31	6/3/94	31	1.58	343.9	214.4	38.6	66.9	24.1	31.9	37.2	1.09	1.16	1.12	0.99	1.79	1.19	84.07

Note: H A Ratio relative to baseline case

TABLE C-9. GR-SI EMISSIONS SUMMARY

Test I. D.	Test Date	Test Duration (hr:min)	Gross Power (MWe)	Gas Heat (%)	Ca/S Molar Ratio	Coal SR	Reb SR	Burn-out SR	Exit SR	OFA (%)	CEMS O2 (%, dry)	Plant O2 (%, wet)	COc (ppm)	CO2c (%)	NOxc (ppm)	NOx (lb/MBtu)	NOx Reduc. (%)	SO2c (ppm)	SO2 (lb/MBtu)	Toll-SO2 Reduc. (%)	Sorb-SO2 Reduc. (%)	Ca Utiliz. (%)
GRSI-11A	9/30/93	1:00	27	24.7	2.26	1.16	0.88	1.20	1.20	27	3.28	2.23	370	13.9	224	0.298	66.26	1,191	2.211	62.52	50.24	22.37
GRSI-11B	10/1/93	0:40	24	22.4	2.13	1.14	0.81	1.31	1.37	30	4.66	3.41	71	14.1	233	0.311	63.07	1,546	2.078	61.22	37.10	17.47
GRSI-1A	10/5/93	1:00	33	22.0	1.77	1.16	0.91	1.24	1.28	26	3.52	2.58	107	14.3	200	0.372	61.29	1,440	2.678	54.65	41.07	23.59
GRSI-1B	10/5/93	1:00	33	22.2	1.83	1.16	0.82	1.31	1.30	30	4.42	3.41	48	14.2	304	0.405	57.97	1,350	2.510	57.46	46.34	27.00
GRSI-1C	10/5/93	0:58	33	22.3	1.68	1.18	0.82	1.36	1.39	32	4.70	3.03	36	14.2	327	0.435	54.00	1,358	2.527	57.17	44.91	28.75
GRSI-13A	10/6/93	1:00	23	20.2	1.90	1.14	0.86	1.26	1.32	31	4.02	2.71	352	14.1	171	0.227	72.78	1,425	2.636	55.33	39.49	20.00
GRSI-13B	10/6/93	1:02	24	20.4	1.80	1.14	0.82	1.24	1.31	26	3.78	2.62	184	14.4	210	0.280	66.71	1,474	2.742	53.52	41.69	21.06
GRSI-13C	10/6/93	1:00	24	17.6	2.00	1.14	0.96	1.23	1.30	22	3.64	2.44	177	14.5	228	0.304	64.10	1,400	2.025	65.61	40.07	22.99
GRSI-13D	10/6/93	1:00	24	14.8	1.81	1.18	1.00	1.26	1.32	20	3.43	2.40	68	14.6	273	0.366	50.01	1,470	2.774	52.08	44.70	23.41
GRSI-11A2	10/8/93	1:00	24	20.2	1.87	1.18	0.83	1.28	1.33	22	3.78	2.76	117	14.2	220	0.293	65.40	1,269	2.307	60.88	45.00	23.20
GRSI-3B	10/7/93	1:02	34	14.2	1.87	1.18	1.01	1.28	1.31	20	3.40	2.60	62	14.0	366	0.482	49.36	1,530	2.077	61.24	43.18	23.16
GRSI-3C	10/7/93	1:02	33	18.6	1.75	1.16	0.95	1.28	1.31	24	3.38	2.47	173	14.4	283	0.377	61.12	1,388	2.592	56.07	46.02	20.33
GRSI-3D	10/7/93	1:00	33	20.7	1.76	1.16	0.83	1.26	1.31	26	3.37	2.48	141	14.3	267	0.356	63.26	1,200	2.302	59.62	49.09	27.99
GRSI-3A	10/7/93	1:00	33	25.6	1.90	1.16	0.87	1.25	1.30	30	3.37	2.40	348	14.0	230	0.316	67.35	1,125	2.091	64.55	52.38	27.60
GRSI-12A	10/11/93	1:00	24	21.8	1.82	1.10	0.88	1.31	1.30	33	4.78	3.62	183	14.0	210	0.292	65.62	1,618	3.011	48.96	34.76	18.05
GRSI-12B	10/11/93	1:00	24	22.2	1.90	1.20	0.95	1.31	1.30	27	4.43	3.20	68	14.1	266	0.341	59.06	1,415	2.631	55.40	42.70	22.50
GRSI-15A	10/11/93	1:00	24	22.2	1.10	1.14	0.91	1.24	1.30	27	3.66	2.65	296	14.1	193	0.257	69.69	1,640	3.047	48.36	33.67	30.47
GRSI-15B	10/11/93	1:00	24	22.2	1.80	1.14	0.80	1.24	1.30	27	3.34	2.41	440	14.1	179	0.238	71.88	1,342	2.498	57.64	45.52	25.29
GRSI-15C	10/11/93	0:31	24	22.4	2.70	1.14	0.80	1.23	1.28	27	3.33	2.40	441	14.1	182	0.243	71.38	1,231	2.301	60.99	48.74	18.40
GRSI-101D	11/2/93	1:00	32	23.4	1.48	1.14	0.88	1.25	1.30	28	4.05	3.13	108	14.3	209	0.304	59.32	1,480	2.760	53.39	39.17	20.33
GRSI-101B	11/11/93	1:00	31	23.3	1.72	1.16	0.80	1.26	1.28	28	3.88	2.81	164	14.3	267	0.350	62.15	1,391	2.604	56.20	42.89	24.99
GRSI-101C	11/11/93	1:00	31	23.0	1.74	1.17	0.82	1.24	1.28	28	4.01	2.79	168	14.2	288	0.390	57.91	1,234	2.290	61.19	49.67	20.47
GRSI-101A	11/11/93	1:00	31	22.8	1.75	1.12	0.88	1.28	1.30	30	4.13	3.03	76	14.2	272	0.362	61.65	1,332	2.472	58.10	45.06	20.16
GRSI-201B	11/12/93	1:00	23	23.3	2.08	1.16	0.80	1.26	1.32	28	4.06	2.80	267	14.2	200	0.266	67.06	1,302	2.420	68.88	46.42	22.63
GRSI-202A	11/12/93	1:05	23	23.0	2.09	1.16	0.81	1.30	1.38	30	5.68	3.27	110	13.8	242	0.321	61.04	1,030	1.916	67.52	57.00	27.66
GRSI-201A	11/12/93	1:10	23	23.1	2.12	1.12	0.88	1.28	1.33	30	4.77	3.01	268	14.1	195	0.260	68.61	1,140	2.124	63.99	53.16	25.13
GRSI-202B	11/12/93	1:00	23	23.3	2.12	1.16	0.81	1.35	1.41	33	6.47	3.77	66	13.7	271	0.360	56.40	1,104	2.198	62.74	51.46	24.23
GRSI-201C	11/12/93	1:00	23	23.2	2.14	1.17	0.92	1.24	1.31	26	3.75	2.57	256	14.2	212	0.281	65.93	1,092	2.030	65.46	55.01	25.65
GRSI	11/15/93	3:15	20	22.2	1.67	1.16	0.82	1.30	1.36	29	5.72	3.61	56	14.1	259	0.343	60.31	1,365	2.528	57.15	44.95	26.84
GRSI	11/16/93	4:53	23	22.2	1.97	1.15	0.82	1.29	1.36	29	6.16	3.42	83	14.0	233	0.310	62.69	1,147	2.137	63.77	53.45	27.12
GRSI	11/17/93	1:00	23	22.1	1.74	1.16	0.92	1.29	1.34	29	4.66	3.41	66	14.3	244	0.325	60.07	1,414	2.630	55.29	42.64	24.54
GRSI	2/16/94	2:08	29	21.5	1.33	1.14	0.82	1.28	1.33	28	4.65	3.74	85	14.2	302	0.402	55.58	1,529	2.852	51.67	30.43	20.05
GRSI	2/18/94	3:09	27	20.0	1.38	1.14	0.83	1.24	1.30	25	4.93	3.28	99	14.2	277	0.369	60.52	1,440	2.700	54.23	42.77	31.01
GRSI	3/28/94	0:34	30	21.7	1.21	1.16	0.82	1.26	1.32	27	4.89	3.57	83	14.3	312	0.414	54.87	1,703	3.169	46.29	31.38	25.97
GRSI	3/29/94	7:03	28	22.4	1.69	1.14	0.81	1.24	1.30	27	4.48	3.32	150	14.2	282	0.376	58.10	1,181	2.201	62.70	51.92	30.67
GRSI	3/30/94	6:34	31	22.2	1.78	1.13	0.80	1.24	1.30	27	4.65	3.32	129	14.2	206	0.300	59.39	1,136	2.113	64.19	53.96	30.37
GRSI	3/31/94	6:26	32	22.6	1.66	1.13	0.90	1.25	1.31	28	4.33	3.31	199	14.2	257	0.337	64.51	1,250	2.336	60.41	40.87	29.50

Notes: Subscript c denotes correction to 3% O2

NOx reduction from correlated baseline: NOx = 0.622 + 0.0134*(load)

SO2 reduction from 5.9 lb/MBtu baseline

TABLE C-9. GR-SI EMISSIONS SUMMARY (continued)

Test I. D.	Test Date	Test Duration (hr:min)	Gross Power (MWe)	Gas Heat (%)	Ca/S Molar Ratio	Coal SR	Reb SR	Burn-out SR	Exit SR	OFA (%)	CEMS O2 (%, dry)	Plant O2 (%, wet)	COc (ppm)	CO2c (%)	NOxc (ppm)	NOx (lb/MBtu)	NOx Reduc. (%)	SO2c (ppm)	SO2 (lb/MBtu)	Tot-SO2 Reduc. (%)	Sorb-SO2 Reduc. (%)	Ca Utiliz. (%)
GRSI	4/4/94	0:36	30	23.3	1.79	1.16	0.81	1.27	1.33	29	4.23	3.13	204	14.1	214	0.205	69.26	1,300	2.415	59.07	46.63	26.11
GR-SI	4/6/94	30:00	29	22.4	1.67	1.16	0.82	1.28	1.33	28	4.58	3.18	171	14.2	234	0.311	65.70	1,257	2.338	60.37	48.93	29.30
GRSI-23-24	5/13/94	14:17	24	21.8	1.86	1.16	0.93	1.28	1.33	28	4.20	3.16	143	14.1	208	0.277	67.43	1,249	2.315	60.77	49.80	26.73
GRSI-19-28	5/13/94	1:56	28	19.6	1.65	1.16	0.86	1.26	1.31	24	3.77	2.59	203	14.1	243	0.325	63.77	1,269	2.372	59.79	50.07	30.34
GRSI-22-28	5/13/94	4:55	28	21.8	1.77	1.19	0.95	1.33	1.37	28	4.35	3.20	206	13.9	270	0.364	59.33	1,192	2.211	62.53	52.08	29.45
GRSI	5/14/94	63:40	29	21.6	1.75	1.15	0.82	1.29	1.32	28	4.13	3.03	210	14.1	243	0.325	64.31	1,162	2.100	63.05	52.07	30.21
GRSI-23-33	6/2/94	0:40	33	22.1	1.64	1.15	0.91	1.24	1.27	27	3.82	2.30	375	14.6	270	0.359	62.82	1,487	2.766	53.11	39.78	24.21
GRSI-23-31	6/2/94	7:40	31	22.7	1.81	1.15	0.91	1.27	1.29	29	4.47	2.79	292	14.5	256	0.340	63.93	1,308	2.429	50.82	46.72	25.79

Notes: Subscript c denotes correction to 3% O2
NOx reduction from correlated baseline: NOx = 0.527 + 0.0134*(load)
SO2 reduction from 5.9 lb/MBtu baseline

TABLE C-10. GR-SI OPERATING SUMMARY

Test I. D.	Test Date	Coal Flow (lb/hr)	Gas Heat (%)	Ca/S Molar Ratio	Reb Gas (scfm)	FGR (scfm)	Cyclone Air (lb/hr)	OFA Flow (scfm)	Sorb Flow (lb/hr)	Srb Inj AirFlow (scfm)	Opac (%)	Steam Load (lb/hr)	SSH Steam (F)	SSH Steam (psig)	PSH Steam (F)	Blr Drum (psig)	BlrBnk G I (F)	BlrBnk G O (F)	AirHtr G O (F)
GRSI-11A	9/30/93	24,484	24.7	2.25	1,382	4,817	221,388	18,220	3,700	3,568	6	244,322	897	881	812	916	891	706	371
GRSI-11B	10/1/93	22,570	22.4	2.13	1,125	5,042	203,246	20,310	3,365	3,779	5	216,351	896	881	793	904	844	666	346
GRSI-1A	10/5/93	29,538	22.0	1.77	1,436	5,829	268,366	21,430	3,591	3,769	6	297,705	889	880	809	936	915	727	370
GRSI-1B	10/5/93	29,549	22.2	1.63	1,449	5,813	268,614	26,181	3,273	3,763	7	298,531	881	881	809	937	916	737	390
GRSI-1C	10/5/93	29,460	22.3	1.60	1,462	5,847	267,938	20,227	3,415	3,763	6	298,208	886	881	817	937	918	738	391
GRSI-13A	10/6/93	20,569	26.2	1.90	1,257	5,018	184,842	19,022	2,767	3,604	6	212,547	886	881	790	904	820	656	346
GRSI-13B	10/6/93	22,330	20.4	1.90	989	4,984	200,282	15,488	2,981	3,580	5	215,810	887	881	788	904	833	668	359
GRSI-13C	10/6/93	23,422	17.5	2.00	857	4,077	210,440	13,811	3,281	3,562	5	220,344	885	881	788	906	843	680	368
GRSI-13D	10/6/93	24,100	14.9	1.91	726	4,764	219,418	12,364	3,207	3,567	5	220,924	886	881	789	906	839	681	369
GRSI-11A2	10/6/93	22,693	26.2	1.97	1,070	5,028	200,500	17,083	3,170	3,632	4	220,913	887	881	805	908	845	685	377
GRSI-3D	10/7/93	32,157	14.2	1.87	915	5,767	292,802	10,430	4,003	3,834	5	298,651	886	881	808	936	909	728	382
GRSI-3C	10/7/93	30,254	18.6	1.75	1,192	5,897	274,831	19,838	3,814	3,894	5	298,138	886	881	810	930	915	731	380
GRSI-3B	10/7/93	28,469	20.7	1.75	1,324	6,000	267,894	21,413	3,547	3,893	4	295,850	885	881	816	930	919	735	386
GRSI-3A	10/7/93	27,855	25.6	1.90	1,656	5,959	253,809	24,639	3,663	3,692	4	295,541	885	881	816	938	926	737	390
GRSI-12A	10/11/93	22,890	21.8	1.82	1,089	4,571	189,167	22,077	2,885	3,651	6	221,265	885	881	779	904	826	654	330
GRSI-12B	10/11/93	22,435	22.2	1.90	1,102	6,001	211,388	17,830	2,940	3,808	6	221,646	888	881	792	906	843	668	349
GRSI-15A	10/11/93	22,413	22.2	1.10	1,101	5,980	201,005	18,788	1,654	3,529	6	218,401	887	881	792	905	824	651	346
GRSI-15B	10/11/93	22,362	22.2	1.00	1,102	5,989	200,320	16,764	2,761	3,659	6	220,973	886	881	795	906	834	660	348
GRSI-15C	10/11/93	27,407	22.4	2.70	1,110	5,847	201,600	16,847	4,133	3,617	6	221,062	886	881	795	900	852	670	350
GRSI-101D	11/2/93	30,110	23.4	1.40	1,603	6,866	271,131	24,423	3,002	3,603	7	288,366	887	871	820	926	842	734	370
GRSI-101B	11/11/93	28,724	23.3	1.72	1,667	6,888	289,000	23,534	3,640	3,720	6	221,265	885	881	779	904	820	654	330
GRSI-101C	11/11/93	30,246	23.0	1.74	1,669	5,950	278,473	22,206	3,590	3,704	6	298,661	886	881	808	936	909	729	382
GRSI-101A	11/11/93	30,428	22.8	1.75	1,567	5,833	289,243	26,734	3,820	3,888	5	177,421	892	881	774	902	805	641	354
GRSI-201B	11/12/93	22,142	23.3	2.00	1,160	5,760	200,486	17,751	3,160	3,770	6	212,647	886	881	790	904	820	650	346
GRSI-202A	11/12/93	22,441	23.0	2.00	1,160	5,857	202,881	19,882	3,222	3,780	4	295,541	885	881	816	938	926	737	390
GRSI-201A	11/12/93	22,344	23.1	2.12	1,150	5,924	188,730	18,327	3,250	3,787	5	215,810	887	881	788	904	833	660	359
GRSI-202B	11/12/93	22,598	23.3	2.12	1,150	5,870	204,429	22,729	3,310	3,770	5	220,924	886	881	789	906	839	681	369
GRSI-201C	11/12/93	22,207	23.2	2.14	1,150	5,931	205,754	15,930	3,259	3,785	5	218,224	891	881	774	903	826	656	355
GRSI	11/15/93	23,350	22.2	1.67	1,146	5,972	211,012	20,005	2,601	3,568	4	220,913	887	881	805	908	845	685	377
GRSI	11/16/93	23,409	22.2	1.97	1,149	5,966	211,201	19,779	3,136	3,753	5	220,344	885	881	788	906	843	680	369
GRSI	11/17/93	23,509	22.1	1.74	1,150	5,976	213,068	19,514	2,804	3,669	6	296,103	901	881	801	932	925	740	397
GRSI	2/16/94	28,269	21.5	1.33	1,333	5,882	254,629	22,886	2,638	3,435	6	244,322	897	881	812	916	891	706	371
GRSI	2/18/94	28,027	20.0	1.38	1,210	5,970	251,407	18,778	2,653	4,627	6	178,081	897	881	760	892	841	666	357
GRSI	3/28/94	29,673	21.7	1.21	1,420	5,637	269,852	22,479	2,469	4,614	4	268,219	890	880	839	928	897	681	345
GRSI	3/29/94	28,019	22.4	1.69	1,394	5,954	252,265	21,059	3,425	4,502	4	252,722	892	881	835	922	900	701	366
GRSI	3/30/94	28,896	22.2	1.70	1,422	5,850	257,232	21,948	3,514	4,521	4	259,411	892	881	832	924	904	705	368
GRSI	3/31/94	29,216	22.6	1.66	1,400	5,943	261,202	23,420	3,327	4,225	4	268,424	891	880	831	927	910	712	372

TABLE C-11. GR-SI OPERATING SUMMARY (continued)

Test I. D.	Test Date	Coal Flow (lb/hr)	Gas Heat (%)	Ca/S Molar Ratio	Reb Gas (scfm)	FOR (scfm)	Cyclone Air (lb/hr)	OFA Flow (scfm)	Sorb Flow (lb/hr)	Srb Inj AirFlow (scfm)	Opac (%)	Steam Load (lb/hr)	SSH Steam (F)	SSH Steam (psig)	PSH Steam (F)	Blr Drum (psig)	BlrUnk O I (F)	BlrUnk O O (F)	AirHtr G O (F)
GRSI	4/4/94	26,151	23.3	1.78	1,372	6,010	237,819	21,002	3,100	4,123	3	252,529	892	881	824	920	920	715	361
GR-SI	4/6/94	26,261	22.4	1.67	1,306	6,066	238,401	21,200	2,970	3,633	4	239,332	891	881	827	917	880	690	370
GRSI-23-24	5/13/94	22,162	21.0	1.86	1,067	6,905	201,531	17,603	2,839	3,041	4	209,729	891	881	812	904	863	682	372
GRSI-19-28	5/13/94	25,932	19.6	1.66	1,078	6,943	237,351	17,132	2,844	2,885	3	246,375	892	879	829	917	902	709	391
GRSI-22-28	5/13/94	25,142	21.8	1.77	1,209	6,818	235,782	21,130	3,052	2,820	3	244,893	888	881	820	916	898	711	384
GRSI	5/14/94	26,735	21.6	1.76	1,271	6,930	241,970	21,705	3,176	2,466	4	255,107	888	882	821	921	896	702	374
GRSI-23-33	6/2/94	30,964	22.1	1.64	1,620	6,000	281,581	23,088	3,487	1,802	6	273,433	896	881	853	932	959	725	374
GRSI-23-31	6/2/94	29,305	22.7	1.81	1,405	5,980	265,484	24,279	3,647	1,652	4	257,962	889	881	867	927	941	730	382

TABLE C-12. GR-SI THERMAL IMPACT SUMMARY

Test I. D.	Test Date	Gross Power (MWe)	Gas Heat (%)	Ca/S Molar Ratio	TotStm H A (MBtu/hr)	Furn H A (MBtu/hr)	SSH H A (MBtu/hr)	PSH H A (MBtu/hr)	GenBnk H A (MBtu/hr)	Attmp H A (MBtu/hr)	AirHtr H A (MBtu/hr)	Furn H A Ratio	SSH H A Ratio	PSH H A Ratio	GenBnk H A Ratio	DrmAtt H A Ratio	AirHtr H A Ratio	Boiler Effic. (%)
GRSI-11A	9/30/93	27	24.7	2.26	281.3	181.3	30.6	60.4	18.0	18.9	34.3	0.84	1.10	1.00	1.02	1.01	1.14	83.35
GRSI-11B	10/1/93	24	22.4	2.13	241.4	166.0	24.4	43.0	17.8	11.7	32.2	0.87	1.06	1.02	1.08	1.27	1.23	83.48
GRSI-1A	10/6/93	33	22.0	1.77	348.6	217.9	40.3	60.1	23.2	25.2	41.8	1.01	1.04	0.98	0.82	1.12	1.12	83.25
GRSI-1B	10/5/93	33	22.2	1.63	349.2	218.3	39.4	68.6	23.0	25.8	44.4	1.01	1.02	0.98	0.81	1.14	1.18	82.64
GRSI-1C	10/5/93	33	22.3	1.68	350.8	217.6	39.6	70.1	23.7	26.5	45.3	1.00	1.02	1.01	0.83	1.16	1.21	82.32
GRSI-13A	10/6/93	23	26.2	1.90	264.2	173.8	27.0	47.6	16.8	13.9	29.3	1.01	1.03	0.99	0.84	1.18	1.14	83.60
GRSI-13B	10/6/93	24	20.4	1.80	264.6	174.6	27.0	47.3	16.2	14.0	29.7	1.02	1.04	0.98	0.81	1.17	1.12	83.60
GRSI-13C	10/8/93	24	17.6	2.00	268.8	177.1	28.1	48.2	16.1	14.6	28.4	1.02	1.04	0.98	0.78	1.17	1.10	83.38
GRSI-13D	10/6/93	24	14.8	1.81	270.6	178.7	28.4	48.8	14.7	14.7	28.8	1.02	1.04	0.98	0.76	1.18	1.12	83.42
GRSI-11A2	10/6/93	24	20.2	1.97	272.8	176.7	30.6	51.4	16.3	18.8	30.8	1.00	1.11	1.03	0.78	1.47	1.14	82.81
GRSI-3D	10/7/93	34	14.2	1.87	348.6	219.6	38.6	68.2	22.3	24.8	41.8	1.02	1.02	0.98	0.78	1.10	1.12	83.32
GRSI-3C	10/7/93	33	18.6	1.76	348.6	218.1	40.4	69.4	22.7	27.7	41.3	1.00	1.05	1.01	0.80	1.21	1.11	82.83
GRSI-3B	10/7/93	33	20.7	1.75	347.8	214.9	40.8	68.4	22.8	28.8	41.7	1.00	1.06	1.01	0.80	1.25	1.11	82.74
GRSI-3A	10/7/93	33	25.6	1.80	347.2	213.6	41.1	69.1	23.2	28.2	41.1	0.89	1.07	1.01	0.82	1.26	1.11	82.50
GRSI-12A	10/11/93	24	21.0	1.82	270.0	180.9	24.8	47.1	17.1	10.0	33.0	1.04	0.92	0.95	0.88	0.79	1.23	83.69
GRSI-12B	10/11/93	24	22.2	1.90	270.0	177.2	27.1	49.1	17.2	13.9	32.4	1.01	1.00	0.99	0.88	1.10	1.21	83.39
GRSI-15A	10/11/93	24	22.2	1.10	268.4	176.2	27.2	48.6	16.4	13.9	30.7	1.02	1.01	0.99	0.85	1.12	1.13	83.81
GRSI-15B	10/11/93	24	22.2	1.80	271.4	177.2	28.0	49.7	16.6	15.1	30.2	1.01	1.02	1.00	0.84	1.19	1.13	83.75
GRSI-15C	10/11/93	24	22.4	2.70	269.4	176.8	27.8	49.3	16.6	15.0	30.6	1.01	1.03	1.00	0.86	1.20	1.14	83.55
GRSI-101B	11/2/93	32	23.4	1.48	368.8	220.6	42.2	72.1	26.7	31.0	46.4	1.05	1.09	1.04	0.93	1.36	1.26	83.31
GRSI-101D	11/11/93	31	23.3	1.72	270.0	180.8	24.9	47.1	17.1	10.0	33.0	1.04	0.82	0.85	0.80	0.79	1.23	83.69
GRSI-101C	11/11/93	31	23.0	1.74	348.6	219.6	38.6	68.2	22.3	24.9	41.8	1.02	1.02	0.88	0.78	1.10	1.12	83.32
GRSI-101A	11/11/93	31	22.8	1.76	218.8	161.0	18.6	37.0	12.3	6.3	26.0	1.02	0.87	0.88	0.89	0.97	1.25	83.70
GRSI-201B	11/12/93	23	23.3	2.06	264.2	173.8	27.0	47.6	16.8	13.9	28.3	1.01	1.03	0.89	0.84	1.18	1.14	83.60
GRSI-202A	11/12/93	23	23.0	2.09	347.2	213.6	41.1	69.1	23.2	28.2	41.1	0.99	1.07	1.01	0.82	1.26	1.11	82.50
GRSI-201A	11/12/93	23	23.1	2.12	264.8	174.8	27.6	47.3	16.2	14.0	29.7	1.02	1.04	0.98	0.81	1.17	1.12	83.50
GRSI-202B	11/12/93	23	23.3	2.12	270.6	178.7	28.4	48.6	14.7	14.7	29.9	1.02	1.04	0.98	0.76	1.16	1.12	83.42
GRSI-201C	11/12/93	23	23.2	2.14	282.2	178.4	23.4	46.0	16.4	7.6	31.6	1.05	0.90	0.95	0.83	0.66	1.20	84.00
GRSI	11/15/93	26	22.2	1.67	272.8	176.7	30.6	51.4	15.3	18.8	30.6	1.00	1.11	1.03	0.78	1.47	1.14	82.91
GRSI	11/16/93	23	22.2	1.97	268.8	177.1	28.1	48.2	15.1	14.6	29.4	1.02	1.04	0.98	0.78	1.17	1.10	83.30
GRSI	11/17/93	23	22.1	1.74	339.8	217.8	35.8	64.4	21.6	17.7	43.9	1.04	0.97	0.97	0.80	0.84	1.18	83.39
GRSI	2/16/94	29	21.5	1.33	261.3	161.3	30.5	50.4	19.0	10.9	34.3	0.94	1.16	1.06	1.02	1.61	1.14	83.35
GRSI	2/18/94	27	20.0	1.38	220.4	151.1	19.8	36.5	13.0	5.4	26.7	1.02	0.99	0.98	0.95	0.82	1.28	83.84
GRSI	3/20/94	30	21.7	1.21	335.2	203.6	37.7	67.0	26.9	29.1	38.7	1.02	1.10	1.08	1.07	1.55	1.16	83.83
GRSI	3/29/94	28	22.4	1.69	321.8	198.6	36.7	63.3	23.6	27.5	37.6	1.03	1.13	1.08	1.00	1.61	1.20	83.33
GRSI	3/30/94	31	22.2	1.70	329.4	204.7	36.3	64.4	24.0	26.4	38.6	1.04	1.09	1.07	0.99	1.46	1.20	83.33
GRSI	3/31/94	32	22.6	1.66	339.2	209.6	38.8	66.4	24.5	28.4	40.1	1.04	1.12	1.06	0.96	1.48	1.20	83.19

Note: H A Ratio relative to baseline case

TABLE C-12. GR-SI THERMAL IMPACT SUMMARY (continued)

Test I. D.	Test Date	Gross Power (MWe)	Gas Heat (%)	Ca/S Molar Ratio	TotStm H A (MBtu/hr)	Furn H A (MBtu/hr)	SSH H A (MBtu/hr)	PSH H A (MBtu/hr)	GenBnk H A (MBtu/hr)	Attmp H A (MBtu/hr)	AirHtr H A (MBtu/hr)	Furn H A Ratio	SSH H A Ratio	PSH H A Ratio	GenBnk H A Ratio	DrmAtt H A Ratio	AirHtr H A Ratio	Boiler Effic. (%)
GRSI	4/4/94	30	23.3	1.78	316.0	199.2	32.8	60.4	23.5	22.0	37.1	1.04	1.03	1.06	1.02	1.33	1.18	83.31
GR-SI	4/6/94	29	22.4	1.87	308.0	192.0	34.4	69.2	21.5	24.7	35.1	1.03	1.13	1.07	0.98	1.60	1.20	83.10
GRSI-23-24	5/13/94	24	21.8	1.80	267.1	162.7	20.1	49.0	17.3	17.6	27.5	0.97	1.11	1.06	0.97	1.60	1.09	82.94
GRSI-19-28	5/13/94	28	19.5	1.65	294.0	177.9	36.2	58.5	20.4	26.5	31.7	0.95	1.18	1.07	0.92	1.70	1.05	82.79
GRSI-22-28	5/13/94	28	21.8	1.77	293.3	181.0	33.5	58.0	20.7	23.0	34.3	0.97	1.10	1.05	0.94	1.40	1.14	82.59
GRSI	5/14/94	29	21.6	1.76	305.0	188.0	34.0	61.0	22.0	23.0	36.0	0.98	1.07	1.05	0.94	1.40	1.12	83.10
GRSI-23-33	6/2/94	33	22.1	1.64	372.0	225.4	43.6	73.3	29.7	35.7	43.8	1.08	1.19	1.11	1.10	1.71	1.28	83.39
GRSI-23-31	6/2/94	31	22.7	1.81	349.1	211.4	41.4	70.4	26.0	36.9	41.5	1.06	1.22	1.15	1.05	1.94	1.30	83.02

Note: H A Ratio relative to baseline case

APPENDIX D

LAKESIDE
NOVACON SORBENT TESTING

NovaCon Sorbent Testing
at Lakeside Station Unit 7
City Water, Light & Power - Springfield, Illinois

Test Report

Prepared by:
Energy and Environmental Research Corporation
1345 N. Main Street
Orrville, Ohio 44667

November 18, 1994

1.0 INTRODUCTION

Testing of sorbents provided by NovaCon Energy Systems, Inc. of Bedford, New York, was conducted at Lakeside Station Unit 7 as part of the Gas Reburning-Sorbent Injection (GR-SI) demonstration. The GR-SI demonstration is a Clean Coal Technology Program (Round 1) sponsored by the U.S. DOE, Gas Research Institute (GRI), Illinois State Department of Energy and Natural Resources (ENR), and the host utility. The work has been carried out by Energy and Environmental Research Corporation (EER). The NovaCon Sorbent Test was co-funded by the Illinois Clean Coal Institute and followed long-term GR-SI testing with Linwood hydrated lime sorbent.

Two types of sorbents referenced as Dolomitic and Calcitic were tested from October 17 to 19, 1994. The Dolomitic sorbent was denoted "90-325," because it has a specified fineness of 90% passing 325 mesh U.S. Standard Sieve, and has a makeup of approximately 55% $CaCO_3$, corresponding to a calcium content of 22%. The Calcitic sorbent is denoted "80-200," with a specified 80% passing 200 mesh U.S. Standard Sieve, and has a makeup of 93% $CaCO_3$, corresponding to 37% calcium content.

These sorbents have an approximate settled density of 90 lb/ft^3. This is three times that of the Linwood calcitic hydrate which has been the baseline sorbent at Lakeside. The difference in bulk density required adjustment to the sorbent feed and air transport systems. Sorbent Injection tests were preceded by a coal only baseline test, from which SO_2 reductions were calculated.

Both Dolomite and Calcite sobents were evaluated by EER in a Boiler Simulation Furnace (BSF), at EER's Santa Ana, California test facility, prior to the full scale evaluation. These tests focused on optimizing SO_2 reduction/calcium utilization and on characterization of fly ash/spent sorbent mixture. SO_2 reductions/calcium utilizations were compared to results obtained with Linwood hydrate. These tests indicated that SO_2 capture depended significantly on the particle size (grind), with fine grinds yielding the best results, and on injection temperature. The optimum injection temperatures for NovaCon sorbents were higher than that of Linwood hydrated lime. This indicated that NovaCon sorbents may perform well in boilers which have relatively high furnace temperature, such as cyclone fired units. A Toxicity Characteristic Leaching Procedure (TCLP) test indicated that the fly ash/spent sorbent mixture, obtained with Dolomite, is not hazardous.

2.0 TEST RESULTS

Results of NovaCon Sorbent testing at Lakeside Unit 7 are summarized in Table 1 and are compared with Linwood hydrate results in Figures 1 and 2. Due to the availability of materials, the sorbents were evaluated with short (typically less than 1 hour data points) parametric tests. The calcium to sulfur molar ratios ranged from 0.90 to 2.52 at full load, but reached 4.06 at reduced load of 22 MW_e. The mass loading of Calcitic sorbent was lower than that of Dolomitic sorbent, due to its higher calcium content. SO_2 reductions for Dolomite 90-325 ranged from 12% (Ca/S of 0.90) to 27% (Ca/S of 1.82). Calcium utilization ranged from 10% at high sorbent addition rates (Ca/S of 1.96 to 2.52), to 15% at low sorbent addition rates (Ca/S below 1.6). SO_2 reduction with the Calcitic sorbent at full load ranged from 17 to 18% (Ca/S of 1.35 to 1.68) to 24% (Ca/S of 2.45). The calcium utilization was in the 10 to 13% range. Testing of Calcite at a reduced load of 22 MW_e indicated reduced performance. At low load, injection of Calcitic sorbent at Ca/S molar ratios of 3.47 to 4.06 resulted in SO_2 reductions of 16 to 18% and calcium utilization of 5%. All SO_2 reductions were calculated from the 5.507 lb/MBtu baseline.

The performance of both the NovaCon sorbents, 90-325 and Calcitic, was significantly below that achieved in earlier BSF experimental testing, and also below that expected for the Lakeside Unit. BSF test data are summarized in Figures 3 and 4, which show SO_2 removal rates as a function of Ca/S and injection temperature respectively. Such data has been used successfully in the past, in the extrapolation, interpolation and evaluation of sorbent performance in a variety of applications.

The data in Figure 3 suggest that the Dolomitic 90-325 sorbent performs similarly to the Linwood calcitic hydrate, which has been the baseline sorbent at Lakeside to date, while the Calcitic sorbent yields SO_2 removal rates at about 63% of the level of Linwood. The data in

TABLE 1. SUMMARY OF NOVACON SORBENT PERFORMANCE
AT LAKESIDE STATION UNIT 7

Test I.D.	Test Date	Sorbent	Gross Load (MWe)	SO2 Emissions (lb/MBtu)	Sorbent Flow (lb/hr)	Ca/S Molar Ratio	Sorbent Injection Air (scfm)	SO2 Reduction * (%)	Calcium Utilization (%)
SI	10/18/94	Dolomite	33.2	4.081	14,341	2.52	4,019	25.89	10.28
SI	10/18/94	Dolomite	32.6	4.345	10,944	1.96	4,053	21.10	10.77
SI	10/18/94	Dolomite	32.7	4.172	8,827	1.57	4,117	24.24	15.44
Test #1	10/19/94	Dolomite	32.8	4.799	5,186	0.90	4,252	12.86	14.28
Test #2	10/19/94	Dolomite	33.3	4.819	5,225	0.90	2,991	12.49	13.88
Test #3	10/19/94	Dolomite	32.8	4.754	5,252	0.91	4,987	13.67	15.03
Test #4	10/19/94	Dolomite	32.8	4.043	10,529	1.82	4,290	26.58	14.61
Test #5	10/19/94	Dolomite	32.9	4.179	9,032	1.56	4,366	24.11	15.46
Test #6	10/19/94	Calcite	33.0	4.182	8,441	2.45	4,352	24.06	9.82
Test #7	10/19/94	Calcite	33.2	4.524	4,683	1.35	4,502	17.85	13.22
Test #8	10/19/94	Calcite	31.6	4.594	5,410	1.68	4,515	16.58	9.87
Test #9	10/19/94	Calcite	22.6	4.618	8,364	3.47	4,433	16.14	4.65
Test #10	10/19/94	Calcite	22.2	4.499	9,896	4.06	4,405	18.30	4.51

* Note: SO2 Reductions Calculated From 5.507 lb/MBtu Baseline

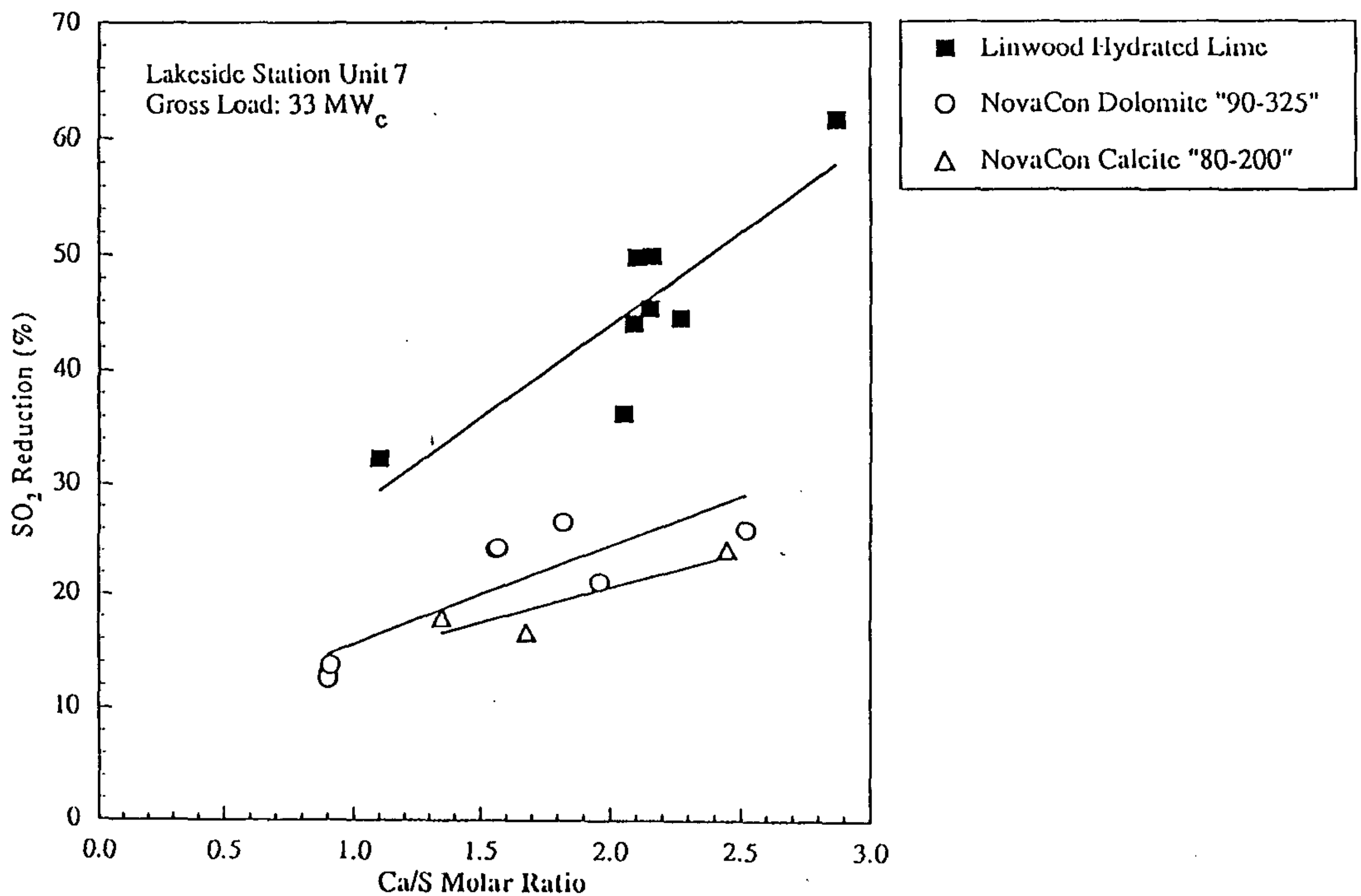


Figure 1. SO_2 reductions of NovaCon and Linwood Hydrated Lime sorbents.

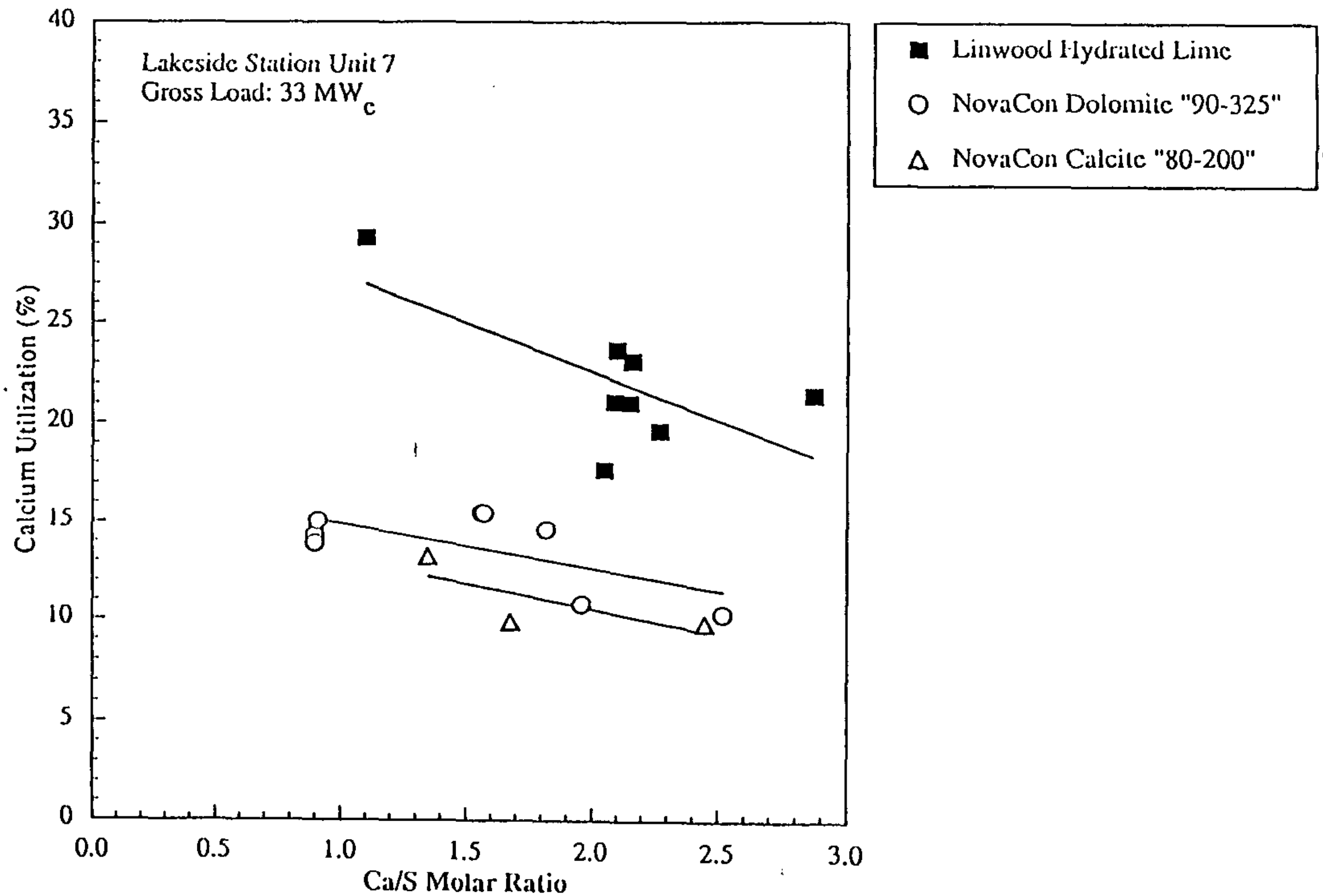


Figure 2. Calcium utilization of NovaCon and Linwood Hydrated Lime sorbents.

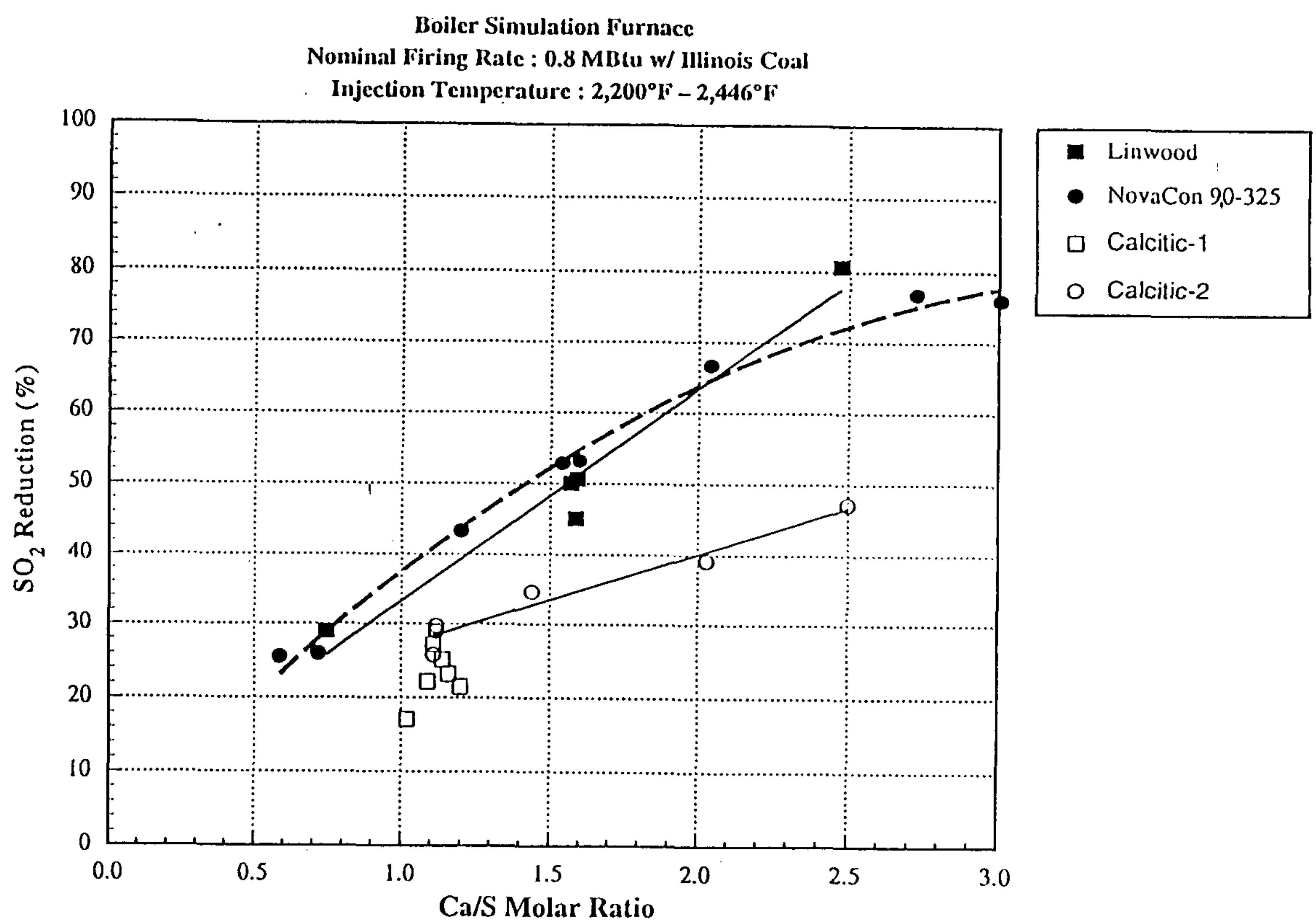


Figure 3. SO_2 reduction as a function of Ca/S molar ratio (BSF).

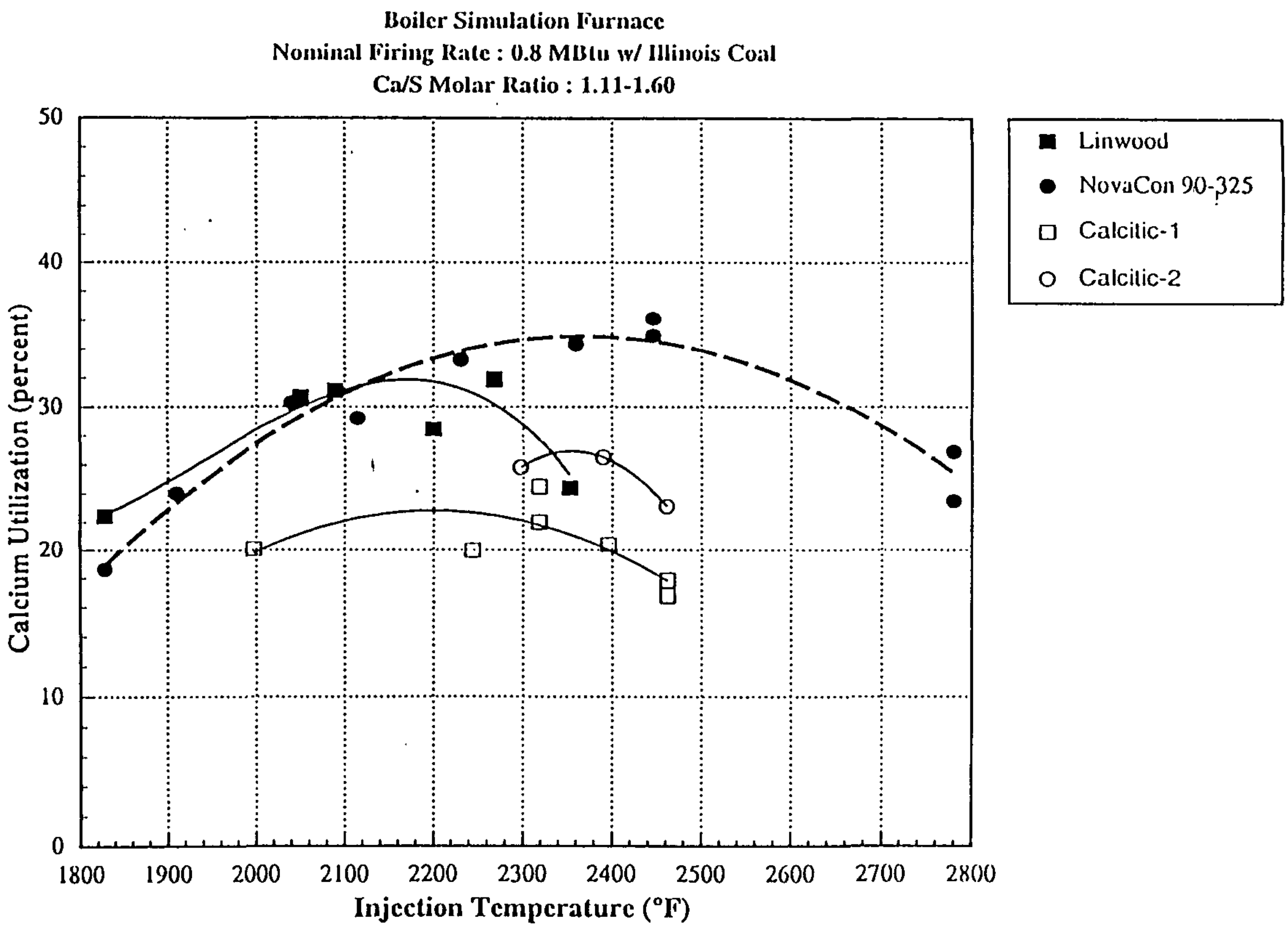


Figure 4. Injection temperature varation test (BSF).

Figure 4 indicate further that both NovaCon sorbents yield optimum performance at an injection temperature some 200°F higher than that for the Linwood hydrate (~2350°F compared to ~2150°F). The BSF data are not expected to translate directly to the Lakeside boiler, since absolute performance will be impacted by parameters such as injection temperature, quench rate and mixing. However, experience suggests that the relative behavior between sorbents should hold. On this basis, and using the data in Figure 3, when the Linwood sorbent achieves 40% SO_2 removal in the boiler the NovaCon sorbents would be expected to yield 40-44% and 30% SO_2 removal respectively. The boiler data in Figure 1 indicate SO_2 removal rates of ~25% and ~19% respectively, corresponding to about 60% of expected values.

The reason for the reduced level of performance of the NovaCon sorbents in the boiler is not immediately apparent from the data, although injection temperature, and temperature quench rate are parameters which can significantly impact sorbent behavior. In this regard it should be noted that the sorbent injection system at Lakeside has been designed to accommodate the properties of the Linwood calcitic hydrate. Mean gas temperatures at the boiler injection elevation are ~2200°F and ~2450°F, at the upper and lower elevations respectively. This is quite close to optimum for the Linwood sorbent at boiler conditions, and the measured performance (Figure 1) is consistent with the mean injection temperature of some 2300°F and a quench rate of ~1000°F/sec.

Both the NovaCon 90-325 and Calcitic sorbents have been shown to prefer somewhat higher injection temperatures, and performance should be expected to improve the injection at a lower elevation in the boiler (~2400 - 2500°F). However, injection temperature does not explain all sorbent behavior, since experience suggests that, to a first approximation, temperature and quench rate affect all sorbents equally, and consequently that the relative behavior between Linwood and NovaCon should translate from the BSF to the field. One explanation may be that the NovaCon sorbents are more sensitive to the higher quench rates which are typical of many field installations (and the Lakeside boiler in particular), though this would be inconsistent with prior experience. Another potential reason for the apparent reduced SO_2 removal performance could be that the sorbents tested at Lakeside are different from those tested earlier in the BSF. Particle size distribution can, for example, have a significant impact on the behavior of both

Dolomitic and Calcitic materials though there are other physical and chemical parameters which may not have been characterized. Some additional evaluation of sorbent samples obtained from the Lakeside tests might be beneficial in resolving any differences.

A Boiler Performance Monitoring System (BPMS) was used to monitor boiler characteristics. The BPMS data indicates that under sorbent injection there was reduced heat absorption by the secondary superheater, but increased heat absorption by the furnace, primary superheater and air heater. This change in heat absorption pattern is due to sorbent deposition. Reduced levels of steam attemperation were required. The unit has a drum type attemperator mounted in the upper steam drum. The secondary superheater outlet steam temperatures were maintained in the range of 887 to 894°F, which is the same as under baseline operation. Overall the changes in thermal performance were very minor. The duration of the tests was not sufficient to characterize the impacts on ESP performance and sootblowing cycles.