Results of Babcock & Wilcox's Clean Coal Technology Combustion Modification Projects: Coal Reburning for Cyclone Boiler NO_x Control and Low NO_x Cell™ Burner Demonstrations

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ABSTRACT

Cyclone furnaces were developed by Babcock & Wilcox (B&W) to effectively combust low quality fuels. B&W's Cell burners were designed to maximize heat release in the boiler to improve efficiency. These objectives were readily achieved through intense combustion and resulting high temperatures; a condition generating disproportionately high levels of NO_x. Each technology represents approximately 13% of pre-New Source Performance Standards (NSPS) coal-fired generating capacity. B&W, co-sponsored by Electric Power Research Institute (EPRI), the host utilities and utility co-funding sponsors through U. S. Department of Energy (DOE) Clean Coal Technology Demonstration projects, addressed the NO_x reduction needs of utilities using cyclones and cell burners. The Ohio Coal Development Office (OCDO) also sponsored the cell burner project as part of its own Clean Coal Technology Program. Coal reburning to reduce NO_x emissions by at least 50% from cyclones was demonstrated at Wisconsin Power and Light Company's (WP&L) 110 MW_e Nelson Dewey Generating Station. The Low-NO_x Cell™ burner (LNCB™) reducing NO_x emissions by at least 50% was demonstrated at the 605 MW_e Unit No. 4 at Dayton Power & Light Company's (DP&L) J. M. Stuart Station. Both emissions and overall boiler performance test results for each Clean Coal Technology Demonstration are presented in this paper.

INTRODUCTION AND BACKGROUND

Coal Reburning

The "Coal Reburning for Cyclone Boiler NO_x Control Demonstration" (Project DE-FC22-90PC89659) is one of the U. S. Department of Energy (DOE) Clean Coal Technology, Round II (CCT-II) Demonstration Program Projects. The objective of the coal reburning demonstration is to evaluate the applicability of the technology to full-scale cyclone-fired boilers for reduction of NO_x emissions. The project goals are:

1. Achieve a minimum 50% reduction in NO_x emissions at full load.

2. Reduce NO_x without serious impact to cyclone operation, boiler performance or other emissions streams.

3. Demonstrate a technically and economically feasible retrofit technology.

The project participants providing funding for the work are:

- DOE - funding co-sponsor
- WP&L - host site utility and funding co-sponsors
- B&W - prime contractor, project manager and funding co-sponsor
- EPRI - testing consultant and funding co-sponsor
- State of Illinois Department of Natural Resource - funding co-sponsor
- Utility funding co-sponsors

  - Allegheny Power System
  - Atlantic Electric
  - Associated Electric
  - Baltimore Gas & Electric
  - Basin Electric Power Cooperative
  - Iowa Electric Light & Power Company
  - Iowa Public Service
  - Minnkota Power Cooperative, Inc.
  - Missouri Public Service
  - Montana-Dakota Utilities
  - Kansas City Board of Public Utilities
  - Kansas City Power & Light
  - Northern Indiana Public Service Company
  - Tampa Electric Company

Currently, 105 operating, cyclone-equipped utility boilers exist, representing approximately 13% of pre-NSPS coal-fired generating capacity (over 26,000 MW_e). However, these units contribute approximately 21% of the NO_x emitted because their inherent, turbulent, high-temperature combustion process is conducive to NO_x formation. Typically, NO_x levels associated with cyclone-fired boilers range from 1.0 to 1.8 lb/10^6 Btu input (NO_x as NO_2). Although the majority of the cyclone units are 20 to 30 years old, utilities plan to operate many of them for at least an additional 10 to 20 years. These units (located primarily in the Midwest) have been targeted for the second phase of the Clean Air Act Amendments of 1990 (CAAA) Title IV (Acid Rain Control) scheduled to go into effect in 2000. In some instances, Title I, Ozone Non-Attainment will accelerate the timetable for compliance.

No economical, commercially-demonstrated, combustion modifications have significantly reduced NO_x emissions without adversely affecting cyclone operation. Past tests with combustion air staging achieved 15 to 30% reductions. Further investigation of staging for cyclone NO_x control was halted due to corrosion concerns, as a result of reducing conditions in the cyclone during air staging. Additionally, because no mandatory federal or state NO_x emission regulation was enforced, no alternative technologies were pursued.

The use of selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) technologies also offer the possibility of controlling NO_x emissions from these units, but at high capital and/or operating costs. Reburning is therefore a promising alternative NO_x reduction approach for cyclone-equipped units with more reasonable capital and operating costs. Reburning also complements a fuel switching SO_2 reduction strategy in that typical derates incurred in switching to a Western low sulfur subbituminous coal are offset by the reburn system's additional capacity.

The coal reburning full scale demonstration is justified via a previous EPRI-sponsored (Project RP-1402-30) engineering feasibility study and EPRI/GRI (EPRI RP-2154-11; GRI:5087-254-1471) pilot-scale evaluation of reburning for cyclone boilers performed by B&W.[1,2] These works indicated that NO_x reduction potential was significant and that the technology would apply to the majority of the cyclone boiler population.

The reburning project is 50 months long, September 1989 through October 1993.

Low NO_x Cell™ Burner

The "Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit" (Project DE-FC22-P0P90545) is one of the U. S. Department of Energy (DOE) Clean Coal Technology (CCT-III) Demonstration Program projects and also part of OCDO CCT program. The objective of the LNCB demonstration is to evaluate the applicability of this technology for reducing NO_x emissions in full scale, cell burner-equipped boilers. The program goals are:

1. Achieve at least a 50% reduction in NO_x emissions.
2. Reduce NO_x with no degradation to boiler performance or life.
3. Demonstrate a technically and economically feasible retrofit technology.

The project participants providing funding for the work are:

- DOE - funding co-sponsor
- DP&L - host site utility, operations and construction management and funding co-sponsor
- B&W - prime contractor, project manager and funding co-sponsor
- EPRI - testing consultant and funding co-sponsor
- OCDO - funding co-sponsor
- Utility funding co-sponsors
    - Allegheny Power System
    - Centerior Energy
    - Duke Power Company
    - New England Power Company
    - Tennessee Valley Authority
    - Cincinnati Gas & Electric Company
    - Columbus and Southern Power Company

Economic considerations, which dominated boiler design during the 1960s, led to the development of the standard cell burner for highly efficient boiler designs. Utility boilers equipped with cell burners currently comprise 13%, or approximately 26,000 MW_e of pre-NSPS coal-fired generating capacity. Cell burners are designed for rapid mixing of the fuel and oxidant. The tight burner spacing and rapid mixing minimize the flame size while maximizing the heat release rate and unit efficiency. Consequently, the combustion efficiency is good, but the rapid heat release produces relatively large quantities of NO_x. Typically NO_x levels associated with cell burners will range from 1.0 to 1.8 $lb/10^6$ Btu input (NO_x as NO_2).

To reduce NO_x emissions, the LNCB has been designed to stage the mixing of the fuel and combustion air. A key design criterion for the burner was accomplishing delayed fuel-air mixing with no pressure part modifications, i.e. a plug-in design. The plug-in design reduces material costs and outage time required to complete the retrofit, compared to installing conventional, internally staged low NO_x burners, thus providing a lower cost alternative to address cell burner NO_x reduction requirements.

Justification for the LNCB full scale demonstration was based on a laboratory test program which was designed to fully characterize the LNCB at several scales: 1.75 MW_e, 30 MW_e, and utility scale.[3] This development work was done in association with EPRI. Several aspects of the LNCB performance including NO_x reduction, unburned carbon (UBC), carbon monoxide (CO), corrosion and impact to furnace exit gas temperature (FEGT) were investigated. Results of the pilot scale studies showed that the LNCB burner arrangement was stable over the burner operating range and that greater than 50% NO_x reduction was possible with acceptable impact to CO, UBC, and FEGT levels.[4]

In 1985, one two-nozzle cell burner was replaced with an LNCB at DP&L's Stuart Station Unit No. 3 to test the mechanical reliability. After three years of normal burner operation, with no signs of material degradation, the test was deemed successful.

The LNCB project covers a 42 month span which commenced in April 1990 and is scheduled for completion in September 1993.

COAL REBURNING

Description of Technology

The Coal Reburning technology combines pulverized coal combustion with existing cyclone-fired technology. Instead of all of the combustion taking place within the cyclones, 20 to 35% of the fuel is diverted to a pulverized coal system and fed to the reburn burners downstream of the cyclones. These additional burners are used to create a reducing zone within the main furnace area. Within this zone, stoichiometries of less than 1.0 are maintained for as long as possible to allow mixing and chemical reduction of NO_x to occur. Overfire air is added higher in the furnace to provide enough air to complete the combustion process. At the furnace exit, the stoichiometry matches the original, unmodified condition.

In the reburn zone, up to 35% (at lower loads) of the total heat input required by the boiler is introduced sub-stoichiometrically. This creates large quantities of unburned (unoxidized) hydrocarbon gases which actively seek oxygen to complete the combustion process. Chemically, this oxygen comes from the NO_x molecules created in the cyclones. The reaction reduces the NO_x to elemental nitrogen (N_2). The combustion process is completed as the flue gas enters the overfire air zone where excess oxygen is available, but at a significantly lower temperature than found within the cyclone (2500 versus 3300F). This lower temperature limits NO_x reformation. Figure 1 presents the various combustion zones of the furnace: the main combustion zone, the reburn zone and the burnout zone.

Reburn System at Nelson Dewey Unit No. 2

The demonstration boiler host site at WP&L's Nelson Dewey Unit No. 2 is shown in Figure 2 and pertinent boiler information is summarized in Table 1.

TABLE 1 - Boiler Information - Nelson Dewey, Unit 2	
Name plate rate	100 MW_e
Type	Steam Turbine
Primary fuel	Bituminous and Subbituminous Coal
Operation date	October 1962 - Unit No. 2
Boiler ID	B&W RB-369
Boiler capacity	Nominal 110 MW_e
Boiler manufacturer	Babcock & Wilcox
Boiler type	Cyclone-Fired RB Boiler, Pressurized
Reburning demonstration fuel	Indiana (Lamar) Bituminous Coal, Medium Sulfur (1.87%)
Burners	Three B&W Vortex - Type Burners, Single Wall-Fired
Particulate control	Research Cottrell ESP
Boiler availability	90% Availability

The reburning system design considerations included pilot-scale testing at the small boiler simulator at the B&W Alliance Research Center, physical and three-dimensional numerical modeling activities and B&W low NO_x burner/overfire air port design experience. The size, number and location of reburn burners and overfire air ports were determined. The design objective was to obtain good mixing at the reburn burner elevation and overfire air ports. This mixing is essential for both NO_x reduction and combustible burnout. In addition, penetration of the reburn burners' fuel streams into the cyclone hot flue gas is of concern because over-penetration or under-penetration would cause tube wastage in the boiler, along with potential burner flame instability problems.

Application of Small Boiler Simulator (SBS)-Pilot Scale testing results as well as physical flow and numerical models to design of the reburn system are described elsewhere.[5,6] The coal reburning system at Nelson Dewey Unit 2 consists of the following items:

(1) Four B&W reburn burners
(2) Four standard dual air zone overfire air ports
(3) An MPS-67 pulverizer and primary air fan
(4) 150 ton coal silo
(5) Pulverizer enclosure building
(6) Control system modifications
(7) Reburn motor control center and power supply transformer
(8) Various flues, ducts, flow control dampers and monitors

The isometric view of the system shown in Figure 3 gives the spacial relationships of each of the components in the system. Integration of the reburn system with the existing plant consists of interfaces with the coal feed tripper conveyor, the air heater outlet, flue gas recirculation system, forced draft fan discharge, hot air recirculation system, penetrations into the boiler, and the control system. Tie-in of all reburn components was accomplished during the Fall outage, from September 16 through October 31, 1991.

Coal Reburning Test Results

The primary test coal for the coal reburning demonstration was an Illinois Basin bituminous coal (Lamar). The majority of the testing was performed while firing this fuel to reflect the higher sulfur bituminous coal fired by many of the utilities operating cyclones. Following the bituminous coal testing, subbituminous Powder River Basin (PRB) coal tests were performed to evaluate the effect of coal switching on reburn operation. In addition, WP&L's strategy to meet sulfur emission limitations as of January 1, 1993 is to fire the low sulfur coal.

Reburning Test Parameters

There were three sequences of testing of the coal reburning system using Lamar coal. Parametric optimization testing was used to set up the automatic controls. Performance testing was run with the unit in full automatic control at set load points. Long-term testing was performed with reburn in operation while the unit followed system load demand requirements. PRB coal was tested by parametric optimization and performance modes.

A test matrix was established in order to determine optimized operation. The test variables included in the matrix along with the approximate ranges tested are:

- Boiler load (37 to 118 MW_e)
- Reburn system percent of total boiler heat input ($\approx$25 to 40%)
- Reburn zone stoichiometry ($\approx$0.83 to 0.96)
- Reburn burner stoichiometry ($\approx$0.35 to 0.70)

- Reburn burner pulverized coal fineness (80 to 98% through 200 mesh)
- Gas recirculation rates to reburn burners (0 to 5% of boiler)
- Reburn burner spin vane and impeller/swirler adjustments
- Overfire air (OFA) port spin vane/sliding disk adjustments
- Economizer outlet O_2% (2 to 4%)

NO_x and CO Emissions

Baseline (no reburning) data for NO_x emissions under various load conditions for both coals are summarized in Figure 4 and in Table 2.

TABLE 2 - Baseline NO_x Levels for Lamar and PRB Coals

Load (MW_e)	Baseline NO_x Emissions - ppm ($lb/10^6$ Btu) Corrected to 3% Oxygen	
	Lamar Coal	Powder River Basin Coal
118	635 (0.86)	-
110	609 (0.83)	560 (0.75)
82	531 (0.72)	480 (0.64)
60	506 (0.69)	464 (0.62)
38	600 (0.82)	-

NO_x levels increase at 38 MW_e during Lamar firing because the boiler goes to single cyclone operation, approaching the heat release conditions and corresponding NO_x emissions achieved at full load.

CO emission levels during baseline operation were low while firing either of the two coal types. Generally speaking, the CO levels were slightly lower during the PRB coal firing tests (approximately 30 to 45 ppm versus 60 to 70 ppm over the load range).

Reburn testing on both the Lamar and PRB coals indicates that varying reburn zone stoichiometry is the most critical factor in changing NO_x emission levels during coal reburning operation. The reburn zone stoichiometry can be varied by altering the air flow quantities (oxygen availability) to the reburn burners, the percent reburn heat input, the gas recirculation flow rate or the cyclone stoichiometry.

Figure 5 represents B&W economizer outlet NO_x and CO emission levels in ppm corrected to 3% O_2 versus reburn zone stoichiometry at full load conditions (110 MW_e) while firing Lamar coal. This figure consists of parametric optimization and performance testing data. Figure 6 presents NO_x and CO emissions while firing PRB coal.

Load versus NO_x emissions for both coals are shown in Figure 7 and summarized in Table 3.

TABLE 3 - Reburn NO_x Emissions Versus Load for Lamar and PRB Coals

Load (MW_e)	Reburn NO_x Emissions/% Reduction from Baseline (ppm/%)	
	Lamar Coal	PRB Coal
118	-	275/-
110	290/52	208/62
82	285/47	215/55
60	325/36	220/53
41	-	220/-

Reburn operation burning PRB produced lower overall NO_x emission levels. Baseline NO_x levels with PRB were approximately 10% lower, and better NO_x reduction is probably due to the higher Western fuel volatile content. Higher volatile content generates higher concentrations of hydrocarbon radicals in the substoichiometric region of the furnace. Figure 7 also shows that PRB NO_x emissions could be maintained at a constant level over the 110 to 41 MW_e load range.

With PRB coal, at loads higher than 110 MW_e, NO_x emissions increased. At 118 MW_e, the NO_x level was 275 ppm (0.37 lb/10^6 Btu). Higher NO_x was due to less percent reburn heat input because of reburn feeder limitations. No baseline NO_x levels were obtained at this higher load because the boiler could not reach it without reburn burners in service.

Electrostatic Precipitator Performance

Considerable analysis was conducted on precipitator parameters during the initial stages of the project. It was anticipated with the Lamar coal that particulate loading would increase by as much as two times, depending upon the percentage of reburn fuel used. The analysis suggested that stack opacity would increase to 18 to 20% (the unit has a 40% opacity limit).

When the reburn system was operated, the opacity remained unchanged or decreased slightly. The results of several precipitator tests showed that the particulate grainloading to the precipitator increased about 37%, much less than the two times expected, while outlet grainloading decreased slightly. In general, precipitator efficiency increased slightly with reburn operation. This is probably the result of increased flyash mean particle size (43% of baseline particles were less than 2 microns in size versus 27% with reburn) and no change in flyash resistivity, which offset increased precipitator inlet grain loading.

The precipitator performance did not change significantly with PRB coal. Opacity was consistent with Lamar coal tests. Increases in inlet grain loading (with the reburn system in service) were not as great as that seen with Lamar coal (20% or less versus 30%). Outlet grain loading and precipitator efficiency were generally unchanged from baseline conditions. There was no apparent change in the flyash to total ash ratio.

Unburned Carbon Efficiency Loss

Figure 8 is a plot of change in unburned carbon boiler efficiency loss (UBCL) from baseline conditions versus steam flow (an indication of boiler load) for both Lamar and PRB coals with reburn in operation. For Lamar coal, the full, medium and low loads UBCL were 0.1, 0.25 and 1.5% higher, respectively, than baseline. Full, medium and low load UBCL increases with the PRB coal during reburn operation were 0.0, 0.2 and 0.3%, respectively. Combustion efficiency improved with PRB fuel as did reburn burner flame stability.

Furnace Exit Gas Temperature

Figure 9 shows the FEGT with and without reburn in service for the two coals tested. At full load firing the Lamar coal, the FEGT decreased by approximately 100 to 150F with reburn in service. The gas recirculation flow with reburn in service would be expected to cause about 25F of this decrease. There was no change in FEGT at 75% load and an increase of 50 to 75F at 50% load with reburn in service.

For the PRB coal tests at full load, the FEGT decreased by approximately 25 to 50F with reburn in service. Once again, the gas recirculation flow with reburn in service would account for approximately 25F of this change. There was no change in FEGT at 75% load and an increase of 75F at 50% load with reburn in service. The FEGT decreases at full load in both cases were reflected in significantly decreased superheater and reheater attemperator spray flows.

Although the explanation for this phenomenon is still unclear, it is believed that changes in emissivity in the furnace under substoichiometry conditions is causing increased furnace heat absorption.

Slagging and Fouling

During reburn system operation with Lamar coal, the operators continually monitored both the boiler internals for increased ash deposition and the On-Line Performance Monitoring System (OPM) for heat transfer changes. At no time throughout the system optimization or long term operation period were any slagging or fouling problems observed. In fact, during the scheduled spring and fall unit outages, internal boiler inspections revealed that boiler cleanliness had actually improved.

Because slagging and fouling is usually time dependent, experience on PRB coal is limited. OPM monitoring of furnace and convective pass heat transfer surfaces indicated no change over baseline, Lamar coal conditions. This is an improvement over previous PRB coal experience (without the reburn system) where careful monitoring of slagging and fouling conditions was required. PRB coal will be burned in the unit in the future and additional information and experience will be gained.

Furnace Corrosion

During the major reburn system installation outage (Fall 1991), extensive furnace wall tube ultrasonic thickness (UT) measurements were taken. In Fall 1992, at the completion of the long term testing, and again during the next scheduled outage in Spring 1993, UT measurements were taken in the same areas of the furnace. Additionally, tube specimens were removed from the rear wall of the furnace in the reburn zone for destructive examination. No observable decrease in tube wall thickness was measured. Follow up UT testing will continue for the next five years.

Hazardous Air Pollutant (HAP) Testing

Hazardous air pollutant (HAP) testing was performed using the Lamar test coal at the request of DOE and EPRI to assess the technology's environmental performance. The work was performed near the end of the testing program. The following streams were sampled:

- Crushed coal from the cyclone feeders
- Reburn coal from the pulverizer outlet
- Molten slag from the furnace
- Flue gas at the precipitator inlet
- Flue gas at the precipitator outlet
- Flyash from the precipitator hoppers

The trace elements analyzed were arsenic, beryllium, cadmium, chromium, lead, nickel, manganese, selenium and mercury. Volatile and semivolatile organics (benzene and toluene), aldehydes and acid gases (hydrogen fluoride and hydrogen chloride) were also tested.

HAP emissions were generally well within expected levels and emissions with reburn were comparable to baseline operation. No major effect of reburning on trace metals partitioning was discernable.

None of the 16 targeted (by Title III of the 1990 CAAA) polynuclear aromatic semivolatile organics were present in detectable concentration, at a detection limit of 1.2 ppb for either baseline or reburn operation. Of the 28 targeted volatile organics analyzed, the only compounds present at detectable levels were benzene and toluene and these are summarized in Table 4.

TABLE 4
Hazardous Air Pollutant Emission Results for Cyclone-Fired Boilers-Organics

Test Condition	Toluene, ppb	Benzene, ppb	Semivolatile PNA, ppb
Average Baseline	0.38	0.84	<1.19
Average w/Reburn	0.44	0.25	<1.60

Aldehydes were not detectable at the 2.8 ppb level for formaldehyde and 1.9 ppb level for acetaldehyde.

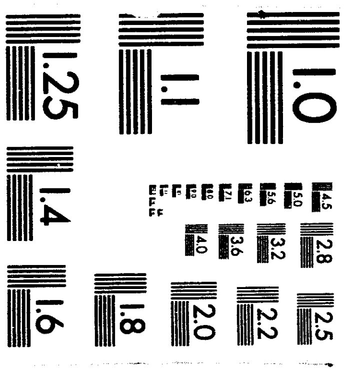
Reburn Results Summary

Table 5 presents a comparison of anticipated and actual results of reburn operation. The reburn system has performed very well as evidenced by WP&L's decision to continue system operations beyond the term of the DOE Coal Reburning Project.

A significant advantage of coal reburning is that it minimizes and possibly eliminates a 10 to 25% derate normally associated with switching to a PRB coal in a cyclone unit. The derate is a result of using of lower Btu content fuel in the volume limited cyclone. The reburn system transfers about 30% of the heat input out of the cyclones to the reburn burners, bringing the cyclone feed rate down to a manageable level, while maintaining full load heat input to the unit. At Nelson Dewey, maximum pre-reburn retrofit full load on PRB coal was 108 to 110 MW_e, while on the higher Btu Lamar coal, 118 MW_e could be achieved. With reburn in operation, the unit was able to achieve 118 MW_e on PRB coal. Accordingly, a reburn system possibly could be economically justified based on fuel cost savings and regained unit capacity when switching to a PRB coal.

TABLE 5
Effect of Reburn System on Unit Performance

Parameter	Anticipated Results	Actual Results
NO_x emissions (full load) Illinois Basin coal	Reduced 50% or more	Nominal 55% reduction
NO_x emissions (full load) Powder River Basin coal	Reduced 50% or more	Nominal 61% reduction
Precipitator opacity	Up 5 to 10%	No increase from base
Slagging/fouling	No change	Cleaner than normal
Furnace corrosion	No change	No change
Header/tube temps.	Higher 25 to 50F	No increase from base
FEGT (Illinois Basin - Lamar coal)	Higher by 50 to 75F	Reduced by 100 to 150F
FEGT (PRB)	Higher by 50 to 75F	Reduced by 25 to 50F
SH & RH sprays (Illinois Basin - Lamar Coal)	Higher by 30%	50% of base
Unburned carbon efficiency loss (full load) Illinois Basin coal	Higher	Higher by 0.1%
Unburned carbon efficiency loss (full load) Powder River Basin coal	Higher	No change
Hazardous air pollutants (Illinois Basin - Lamar coal)	No change	No change


1.0
1.1
1.25
1.4
1.6
1.8
2.0
2.2
2.5
2.8
3.2
3.6
4.0
4.5
5.0
5.6
6.3

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LOW NO_x CELL BURNERS (LNCB)

Description of Technology

The original cell burner design consisted of two or three circular burners mounted in the lower furnace. Figure 10 shows a two-nozzle cell burner. The two-nozzle LNCB shown in Figure 11 was developed by B&W in association with the EPRI. The features of the LNCB were designed to minimize the formation of thermal and fuel NO_x. The two original circular burners in each cell are replaced with a single S-type circular burner and a close coupled secondary air injection port. The flame shape is controlled using an impeller at the exit of the burner and adjustable spin vanes in the secondary air zone. The air port louver dampers provide additional control over the mixing between the fuel and air streams. The S-burner operates at a low air-fuel stoichiometry, typically 0.6, with the balance of air entering through the adjacent air port. The delayed mixing of the fuel and air during the initial stage of combustion limits the formation of NO_x.

Low NO_x Cell Burners at J. M. Stuart Station Unit No. 4

The host site for the full scale demonstration of the LNCB was DP&L's J. M. Stuart Station Unit No. 4 (JMSS4). JMSS4 is a B&W 605 MW_e Universal Pressure (UP) boiler, a once-through design, originally equipped with 24, two-nozzle cell burners arranged in an opposed wall configuration as shown in Figure 12.

Each of the original two-nozzle cell burners were replaced with a single S-type circular burner in place of the lower cell burner and a close coupled secondary air injection port at the upper cell location, shown in Figure 11. To avoid replacing coal pipes and pulverizer top housings, the two coal pipes, one to each burner of the original cell, were combined at the burner front to supply the new single S-type circular burner by using a special Y-pipe assembly. As a special feature of the LNCB technology, no pressure part modifications were necessary and the existing control system was utilized. The retrofit of the LNCB equipment was completed during a six week scheduled turbine outage during October/November 1991.

Initial test results with this original arrangement (Figure 13) indicated high levels of CO and hydrogen sulfide (H_2S) in the lower hopper region of the furnace, an unacceptable operating condition in this pressurized furnace. As a demonstration project, resources were allocated to perform in depth background work to develop the numerical model to help understand flow behavior in the unit. When problems with the LNCB operation arose, B&W used its three dimensional numerical modeling capabilities to simulate the existing operating condition, as well as evaluate alternative burner/secondary air port arrangements that could mitigate this problem. The best computer generated analysis identified for maximum mitigation of CO and H_2S levels was to invert the air port and burner of every other LNCB on the lowest level of burners (Figure 14).[7] This is the final configuration for which results are subsequently reported in this paper.

A second result of initial testing showed that NO_x reduction of only 35% from baseline levels was being achieved with the 50 degree coal impellers. By retracting the impellers within the coal nozzles, NO_x reduction increased to 45%. This indicated a need for an impeller design change in order to achieve the NO_x reduction goals of the project. A coal impeller with a 25 degree included angle was designed, fabricated and installed during the same one week outage in April 1992 in which the alternating inverted LNCB arrangement was accomplished.

Low NO_x Cell Burner (LNCB™) Test Results

The LNCB demonstration emphasized evaluation of boiler performance, boiler life and environmental impact. Key boiler performance parameters that were measured included boiler output (steam temperatures); flue gas temperatures at the furnace, economizer and air heater exits; the slagging tendencies of the unit; and UBC losses. Evaluation of H_2S levels, ultrasonic testing of lower furnace tube wall thicknesses and destructive examination of a corrosion test panel were the mechanisms used to predict impact on remaining boiler life. Environmentally, NO_x, CO, carbon dioxide (CO_2), total hydrocarbons (THC) and particulate matter, dust loadings and precipitator collection efficiency were measured at varying test conditions.

NO_x, CO Emissions and Unburned Carbon Losses

Full Load, 6 Mills In Service (Avg. 604 MW_e)

At full load conditions, averaging 604 MW_e with all mills in service, average NO_x emissions were 0.53 lb/10^6 Btu of heat input to the unit. This represents a NO_x reduction of 54.4%, averaging all data. Figure 15 presents NO_x data for both baseline (pre-retrofit) and post-retrofit operation as a function of excess air.

Emissions of CO under the same conditions ranged from 28 to 55 ppm.

The weighted average of unburned carbon content in ash (UBC) for samples collected from the boiler bottom ash hopper, the boiler outlet hopper and the precipitator first field hopper was 1.12% during full load operation, all mills in service, averaging 604

MW_e. This represents an unburned carbon efficiency loss (UBCL) of 0.2%. This is a 56% improvement over baseline unburned carbon losses and is most likely the result of improved air flow distribution provided by the LNCB retrofit.

Full Load, 5 Mills In Service (Avg. 604 MW_e)

A total of six tests were conducted at full load with a different mill out of service for each test. Each mill provides pulverized coal to four LNCBs. Figure 16 shows burner/mill combinations.

The average NO_x emissions level for full load, five mills in service was approximately 0.51 lb/10^6 Btu. This represents an average reduction from baseline conditions of 53%. Figure 17 presents the NO_x data for both baseline and post-retrofit conditions.

NO_x emissions were lowest at approximately 0.48 lb/10^6 Btu when either of mills A or F was the out-of-service mill. These mills fire the upper outer two burners on each side of the furnace. The highest NO_x levels occurred when mill D was out of service, at 0.56 lb/10^6 Btu. Mill D fired the lower outer two burners on each side of the front wall. Mill C out of service also experienced higher NO_x emissions at 0.52 lb/10^6 Btu as the lower outer two burners on each side of the rear wall were taken out of service. Apparently, with upper burners out of service and the remaining burners firing harder, slightly more NO_x reduction is achieved, possibly due to deeper staging of the lower burners followed by more secondary air available at the burner out-of-service level.

The average CO emissions rate ranged between 20 and 38 ppm during one mill out of service testing. The weighted average for UBC samples was 2.52%. This represents a small reduction from baseline UBC levels which translates to a small improvement in UBC efficiency losses from 0.46% baseline to 0.42% post-retrofit.

Intermediate Load, 5 Mills In Service (Avg. 460 MW_e)

For these tests, Mill A was chosen to be out of service because NO_x emissions at full load A mill out of service were among the lowest observed with one mill down. Figure 18 shows NO_x emissions versus excess air for this test mode. Average NO_x emissions rate for intermediate load condition with five mills running was 0.42 lb/10^6 Btu input corresponding to a 54% reduction in NO_x emissions from similar baseline conditions.

The average CO emissions rate for this intermediate load condition ranged between 28 and 45 ppm. The weighted average of UBC for all sample locations averaged 0.98% for all of the tests at this condition. The efficiency impact due to unburned combustibles loss is 0.17%. This reflects a decrease in the carbon-in-ash levels from those obtained during the baseline tests and also represents a 64% improvement in UBC efficiency losses when compared with the baseline case.

Low Load, 4 Mills In Service (Avg. 350 MW_e)

For low load conditions, mills A and F were out of service because best NO_x reduction was achieved at full load with the upper burners out of service. They were also chosen to test the ability of the LNCB's to maintain low NO_x while the boiler was pushed to maintain reheat superheater steam temperature. This condition represents the original reheat superheater outlet temperature control point.

Figure 19 shows NO_x emissions rate versus excess air for baseline and post-retrofit test conditions at low load. The average NO_x level was 0.37 lb/10^6 Btu which represents a reduction of about 48% from baseline. Emissions of CO ranged from 5 to 27 ppm. The weighted average of UBC for all sample locations averaged 3.17% for all tests, which represents a 0.59% efficiency loss due to unburned carbon. This is an 18% increase in efficiency loss compared to baseline results.

One-Day Test

On March 1, 1993, one day of emissions testing was conducted with all mills in service at JMSS4. The purpose of the test was to evaluate NO_x emissions along with flyash UBC levels eight months after completion of optimized testing. The results are shown in Figure 20. NO_x averaged 362 ppm (0.49 lb/10^6 Btu) at 2.6% O_2 (dry) at an average boiler load of 603.5 MW_e. The fuel used during the test averaged 11,736 Btu/lb with 14.1% ash and a fixed carbon to volatile matter (FC/VM) ratio of 1.45. Flyash grab samples obtained from the first field of the precipitator hoppers and bottom ash samples were analyzed for UBC. The weighted average UBC for the one-day test was 0.97%. This is a very good result, however, it is based on grab samples of ash in the precipitator hoppers and was not isokinetically collected. Basically, this shows no problem with UBC, which was the purpose of the grab samples.

Long Term Averages

An important aspect of the project was to record NO_x emission levels from JMSS4 during normal load dispatch operations over a long period. Table 6 shows the average NO_x emissions for JMSS4 with all mills in service as recorded by the Acurex CEM equipment through a total of two probes located one in each of the east and west economizer outlet ducts. This data was acquired between August 1992 and March 1993 during periods when the boiler was operating above 590 MW_e. The number of days in each month with all mills in service, full load conditions is shown in the first column. All other days represent operation at lower load; mills out of service; or the Continuous Emissions Monitor (CEM) out of service or in calibration. The average NO_x level achieved for the eight month period was 0.49 lb/10^6 Btu or a 58% reduction from baseline. The highest monthly average NO_x level observed was in January at 0.56 lb/10^6 Btu. Wet coal and accompanying problems were suspected to have caused the higher level which still represented a 52% reduction. The excess O_2 levels averaged 3.2%.

TABLE 6 - Long Term Full Load All Mills In Service Data

All Mills In Service Averages at JMSS4
Acurex CEM Test Results for Loads Above 590 MW_e

Month	Days	All Mills In Service			
		Load MW_e	Dry O_2 Econ Out	Dry NO_x ppm Corr. to 3% O_2	NO_x lb/10^6 Btu
August	8.54	604	3.7	367	0.50
September	7.29	604	3.2	333	0.45
October	14.51	605	3.3	367	0.50
November	12.03	605	3.2	345	0.47
December	4.94	605	3.1	360	0.49
January	6.83	605	3.2	410	0.56
February	7.22	606	3.2	364	0.50
March	17.66	602	2.9	353	0.48
Weighted 8-month avg.		604	3.2	360	0.49
Total Days	79.02				

Table 7 shows the full load, mill out of service NO_x emission levels recorded during this same period. The lower NO_x levels recorded with either A or F mill out of service, as observed previously, can be attributed to the fact that these mills feed the burners on the upper elevation only.

Overall unit efficiency remained essentially unchanged from baseline to optimized LNCB operation. The current operation of

JMSS4 at a lower overall excess air since optimization, has reduced the dry gas loss and increased boiler efficiency slightly.

TABLE 7 - Long Term Full Load Mill Out of Service Data					
Mill Out of Service Averages at JMSS4 Acurex CEM Test Results for Loads Above 590 MW_e					
Mill Out of Service	Days	August '92 - March '93			
		Load MW_e	Dry O_2 Econ Out	Dry NO_x ppm Corr. to 3% O_2	NO_x lb/10^6 Btu
A	1.04	603	3.4	314	0.43
B	1.81	608	3.6	361	0.49
C	1.41	602	3.5	388	0.53
D	2.29	602	3.6	404	0.55
E	3.02	606	3.3	357	0.49
F	8.48	604	3.9	314	0.43
Weighted 8-month avg.		604	3.7	343	0.47
Total Days	18.05				

Corrosion Studies

During burner installation in October/November 1991, a corrosion test panel was installed on the boiler side wall between the upper and lower burner rows to evaluate corrosion potential. The panel consists of SA-213T2 bare tube material, aluminized spray coated T2 tube material, 309 L and 308 L stainless weld overlays on T2 tube material and a chromized T2 tube material. In addition, UT measurements were conducted in the furnace.

Preliminary analysis from destructively examining the furnace wall samples taken from the corrosion test panel show localized corrosion near the center of the panel. Tube thickness wastage readings on the bare T2 material ranged from as little as 0.002 in. (2 mils) to a maximum of 0.015 in. (15 mils) per year for the 15 months of operation. This 15 months also includes the 6 months of operation prior to the burner inversion when high levels of CO and H_2S were present in the lower furnace. The amount of wastage also varied with the tube metal temperature, i.e., second pass tubes experienced slightly higher losses than did first pass tubes. These wastage rates are not significantly higher than those experienced on the side walls in the burner zone with the original cell burners in place.

The coated tubes in the corrosion test panel experienced no loss (wastage) of materials. Analysis of the bare T2 material above the burner zone, below the burner zone and around the burners also indicated no metal loss.

UT testing of the furnace will continue over the next five years to evaluate corrosion potential.

CONCLUSIONS

Both the Coal Reburning and LNCB projects have achieved the respective Clean Coal Program objectives. Both technologies have demonstrated NO_x reductions in excess of 50% without significant adverse impact to other boiler emissions streams. The host site units have each continued to reach pre-retrofit full load output without significant impact to boiler operation. Results of long term emissions testing indicate performance has continued to exceed the project goals for each technology and both DP&L and WP&L[8] have decided to operate the respective Clean Coal Technologies beyond the project end dates.

The low cost and short outage time for a LNCB retrofit make the design financially attractive. In a typical retrofit installation, the capital cost will include the LNCB hardware, coal pipe modifications, hangers, support steel, sliding air damper drives and associated electrical, with a capital cost of about $5.5 to $8.0 per kW in 1993 dollars, based upon the DOE 500 MW_e reference unit for material and erection. The outage time can be as short as five weeks because the LNCB is a plug-in design.

For cyclones, coal reburning offers a NO_x reduction alternative at a higher price. Costs are expected to be in the $65/kW range for a 100 MW_e unit and in the $40/kW range for a larger 600 MW_e unit. Unlike a burner retrofit which already has coal handling and pulverizers/coal piping in place, this equipment must be included in the cost of a reburn system. Site specific factors related to pulverizer location and coal supply can greatly influence overall reburn system cost. However, coal reburning brings with it benefits allowing increased flexibility in coal selection which can yield significant fuel savings.

Corrosion potential will continue to be investigated over the next five years for both technologies.

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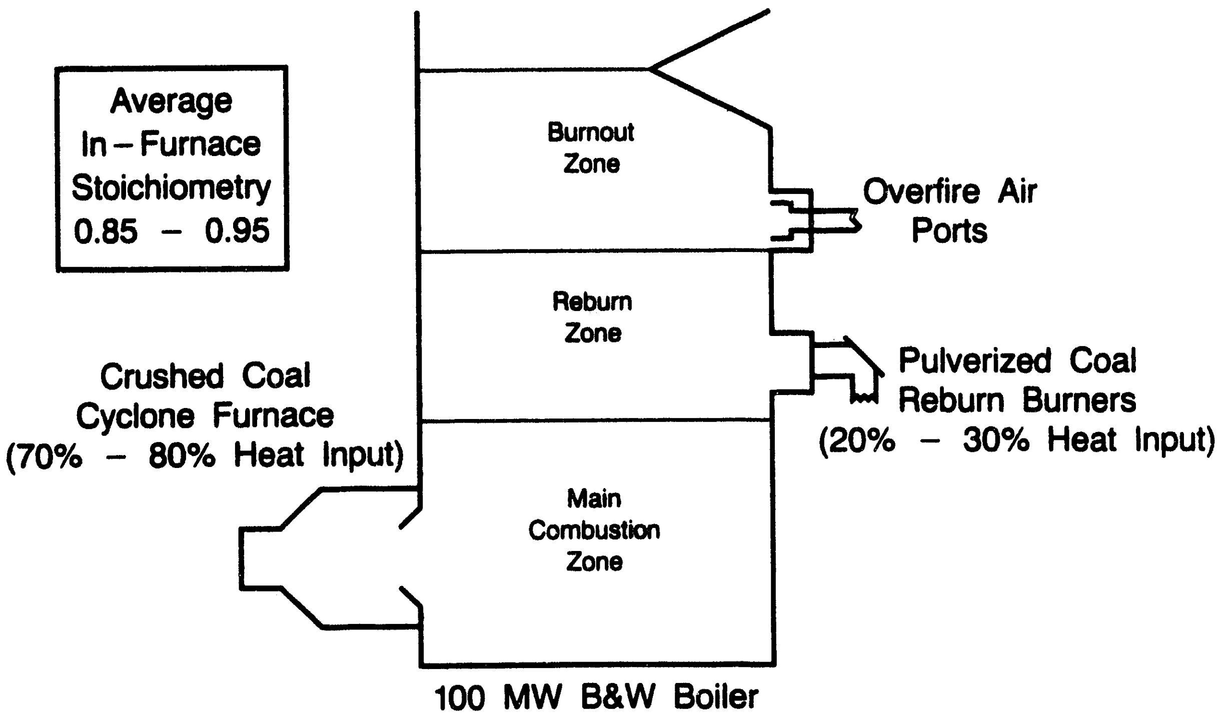

Fig. 1 Cyclone reburn combustion zones.

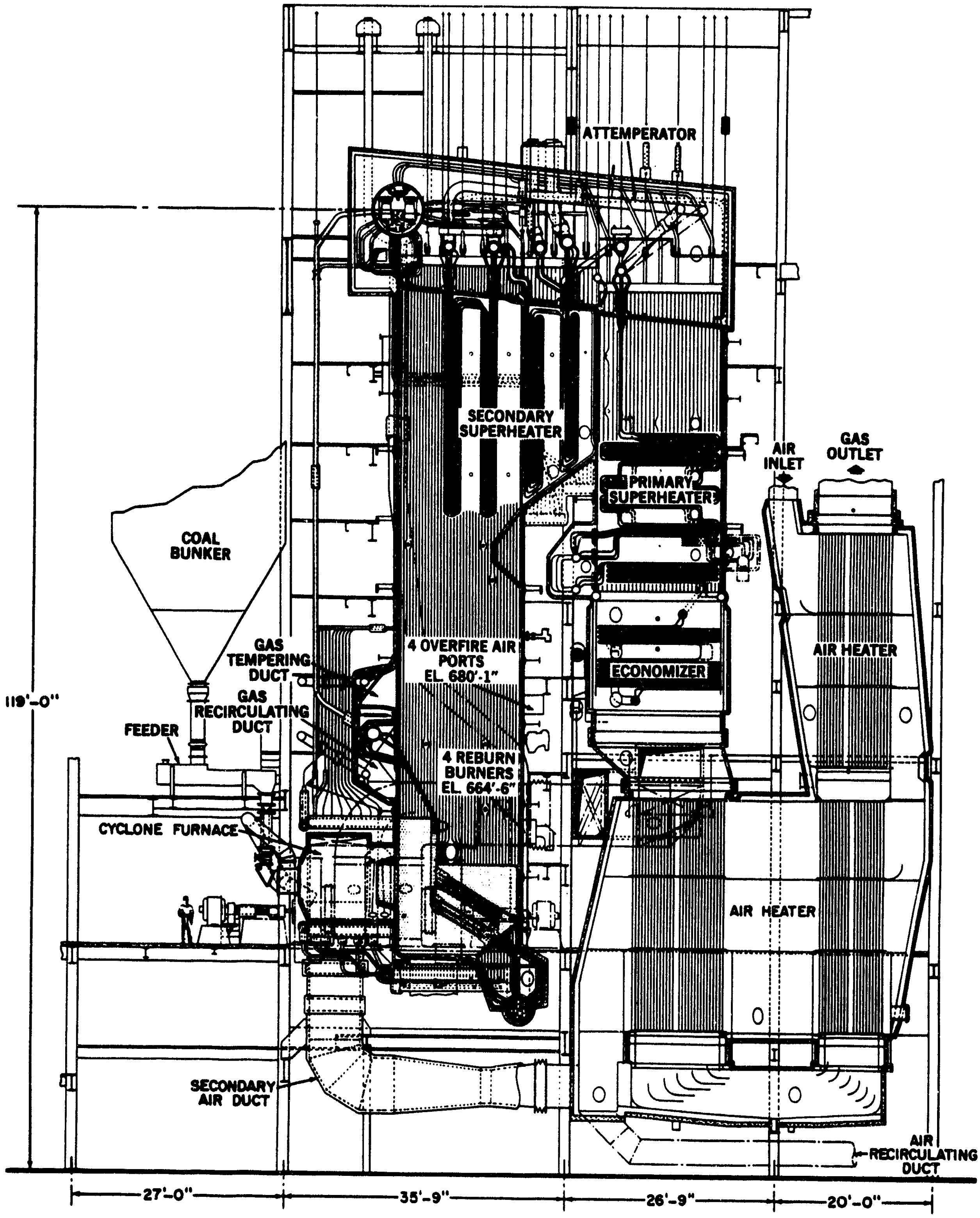

Fig. 2 WP&L Nelson Dewey Unit No. 2.

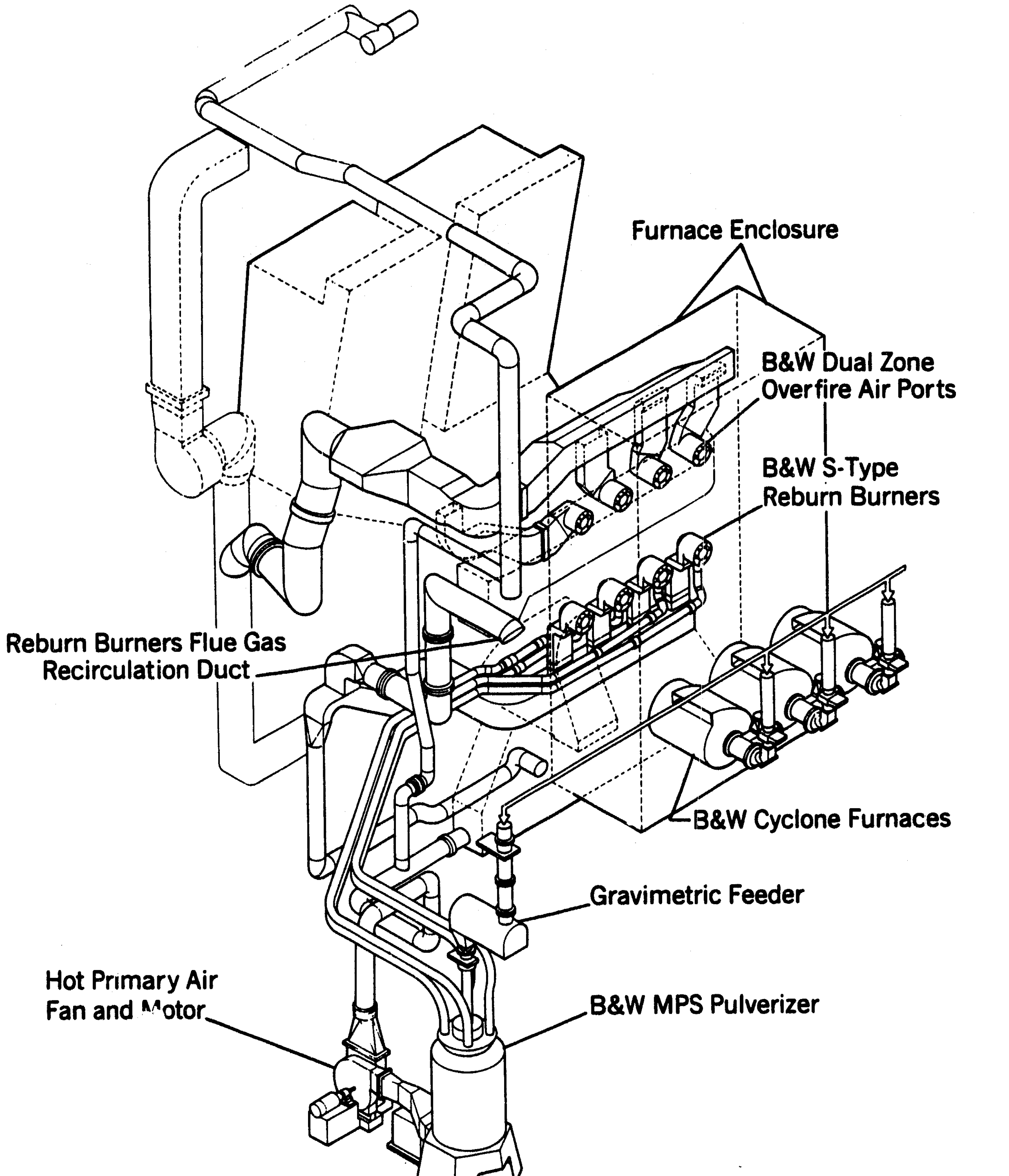

Fig. 3 Isometric view of Coal Reburning for Cyclone Boiler NO_x Control.

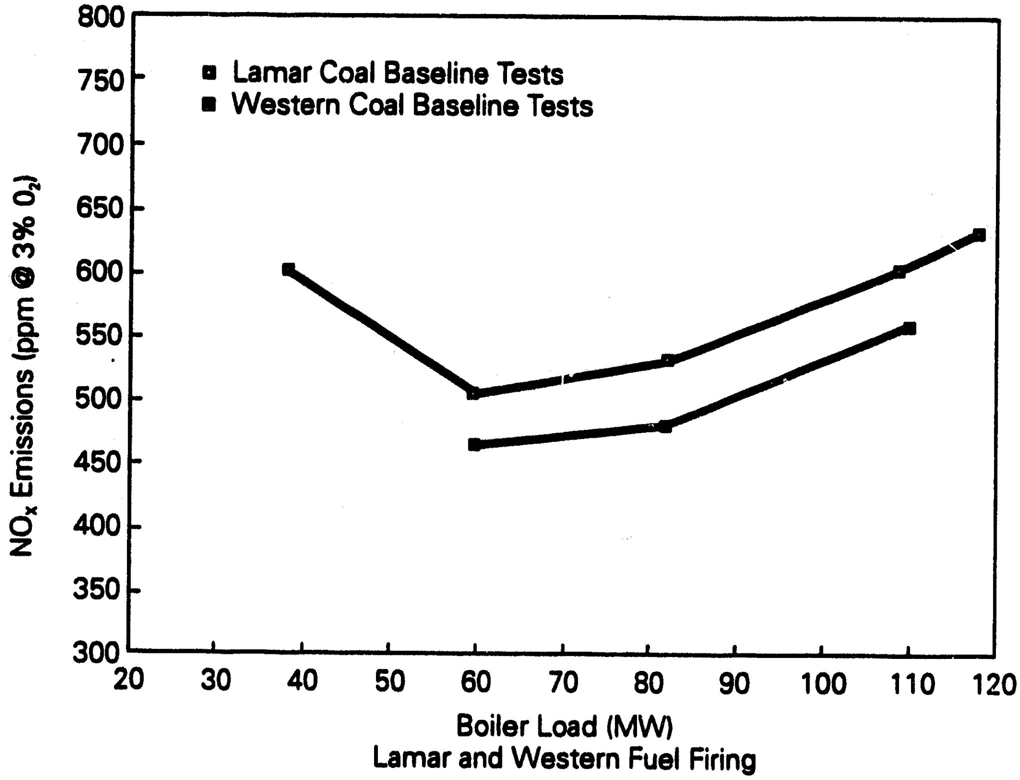

Fig. 4 Baseline NO_x emissions versus load, Nelson Dewey Unit 2.

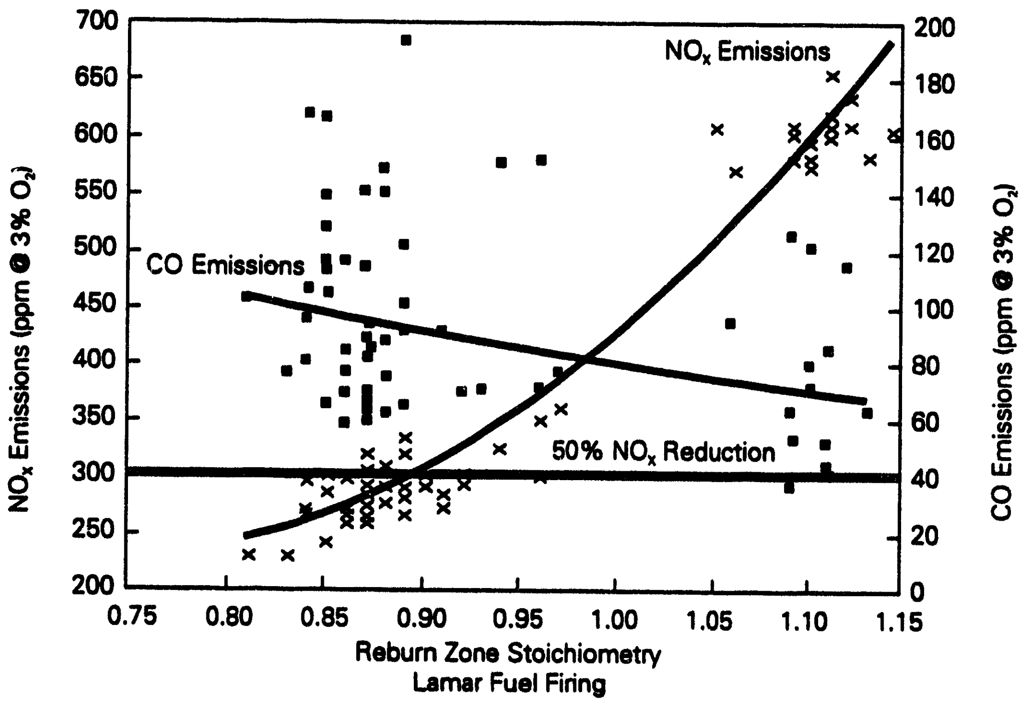

Fig. 5 NO_x and CO emissions versus reburn zone stoichiometry at full load firing Lamar coal.

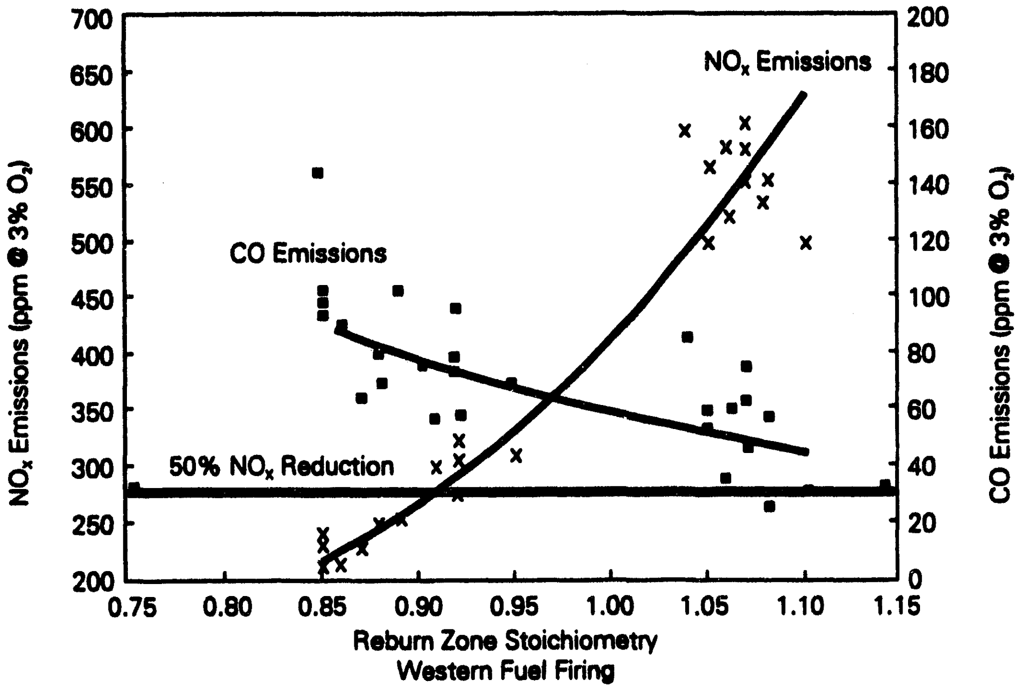

Fig. 6 NO$_x$ and CO emissions versus reburn zone stoichiometry at full load firing Western coal.

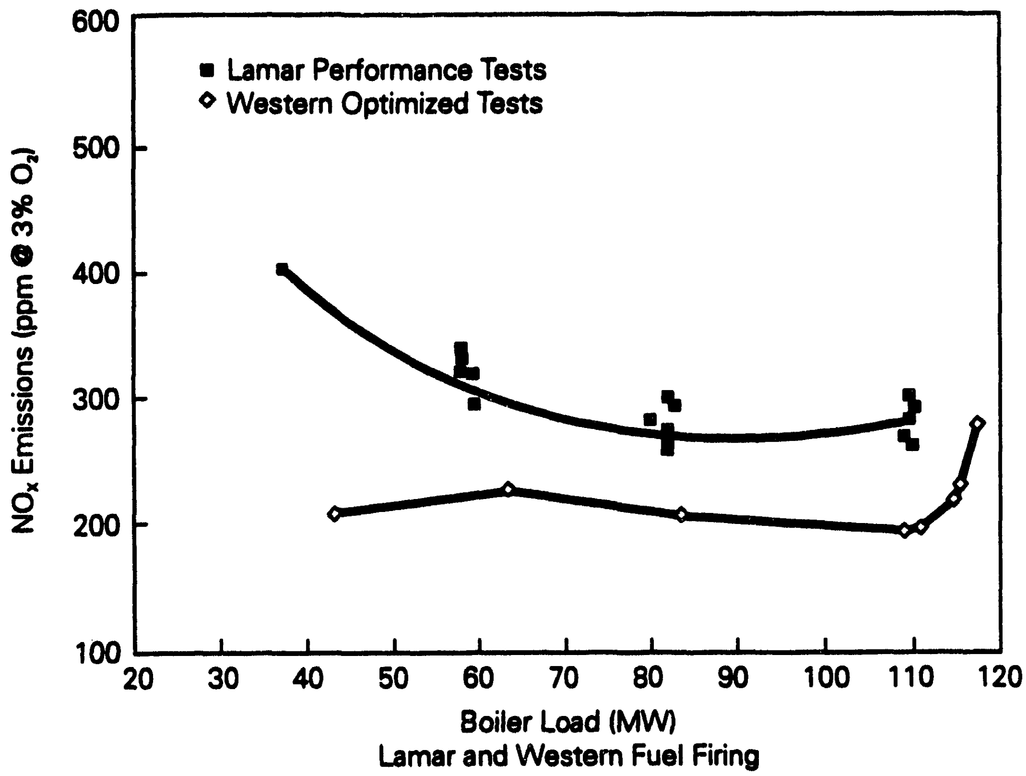

Fig. 7 NO$_x$ emissions versus load firing Lamar and Western coals with reburn system in operation.

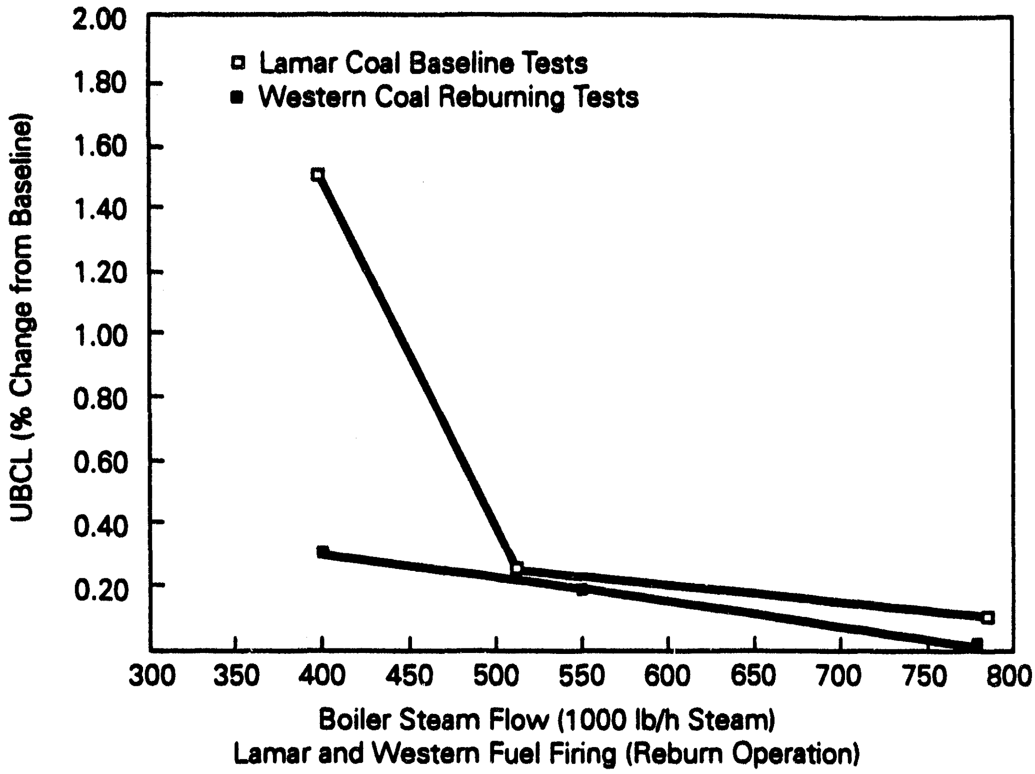

Fig. 8 **Unburned carbon efficiency loss versus load with reburn system in operation.**

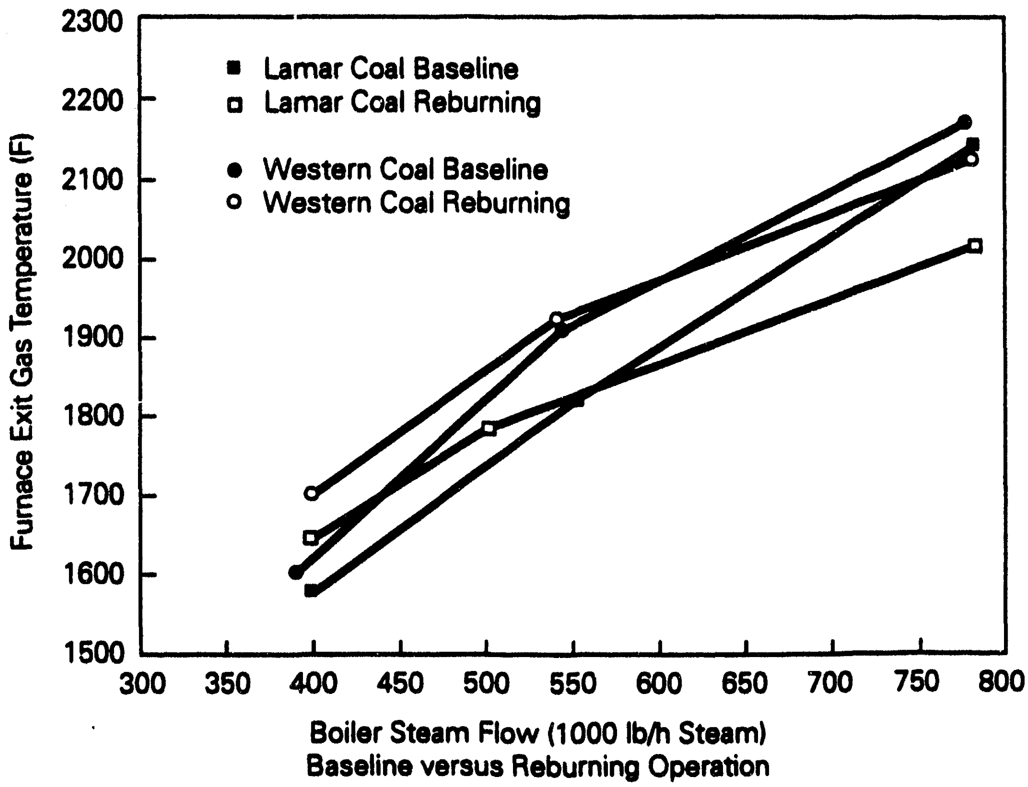

Fig. 9 **Comparison of baseline and reburn system furnace exit gas temperatures.**

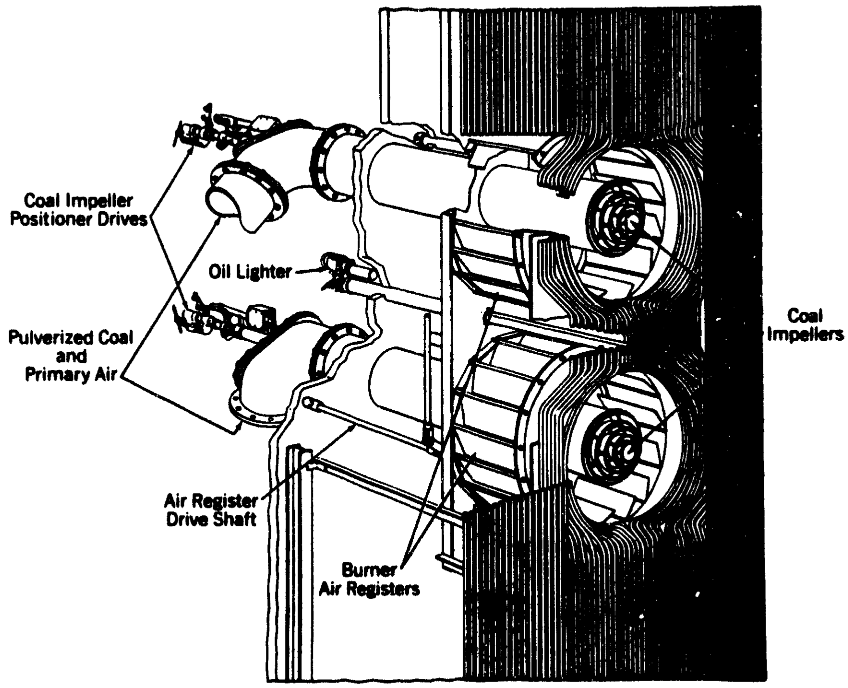

Fig. 10 Standard two-nozzle cell burner.

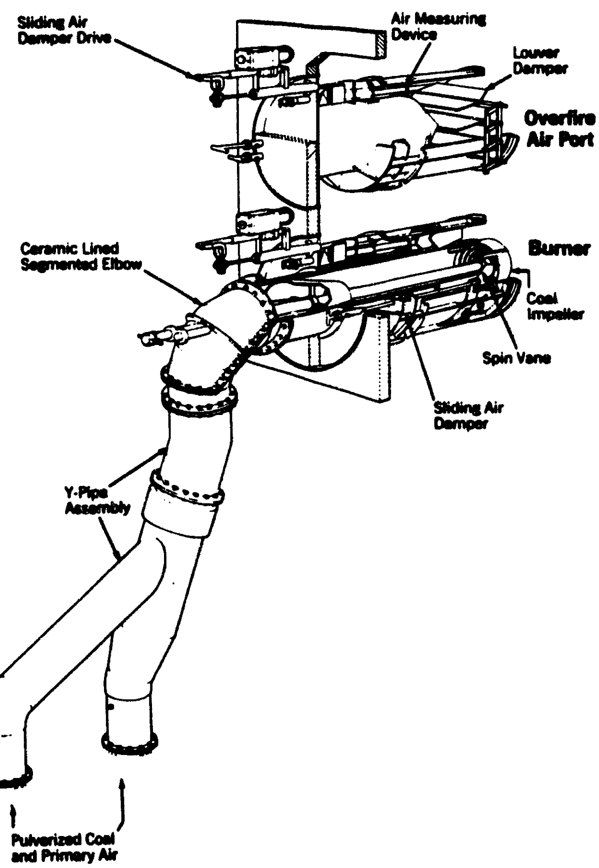

Fig. 11 Low NO_x Cell™ burner.

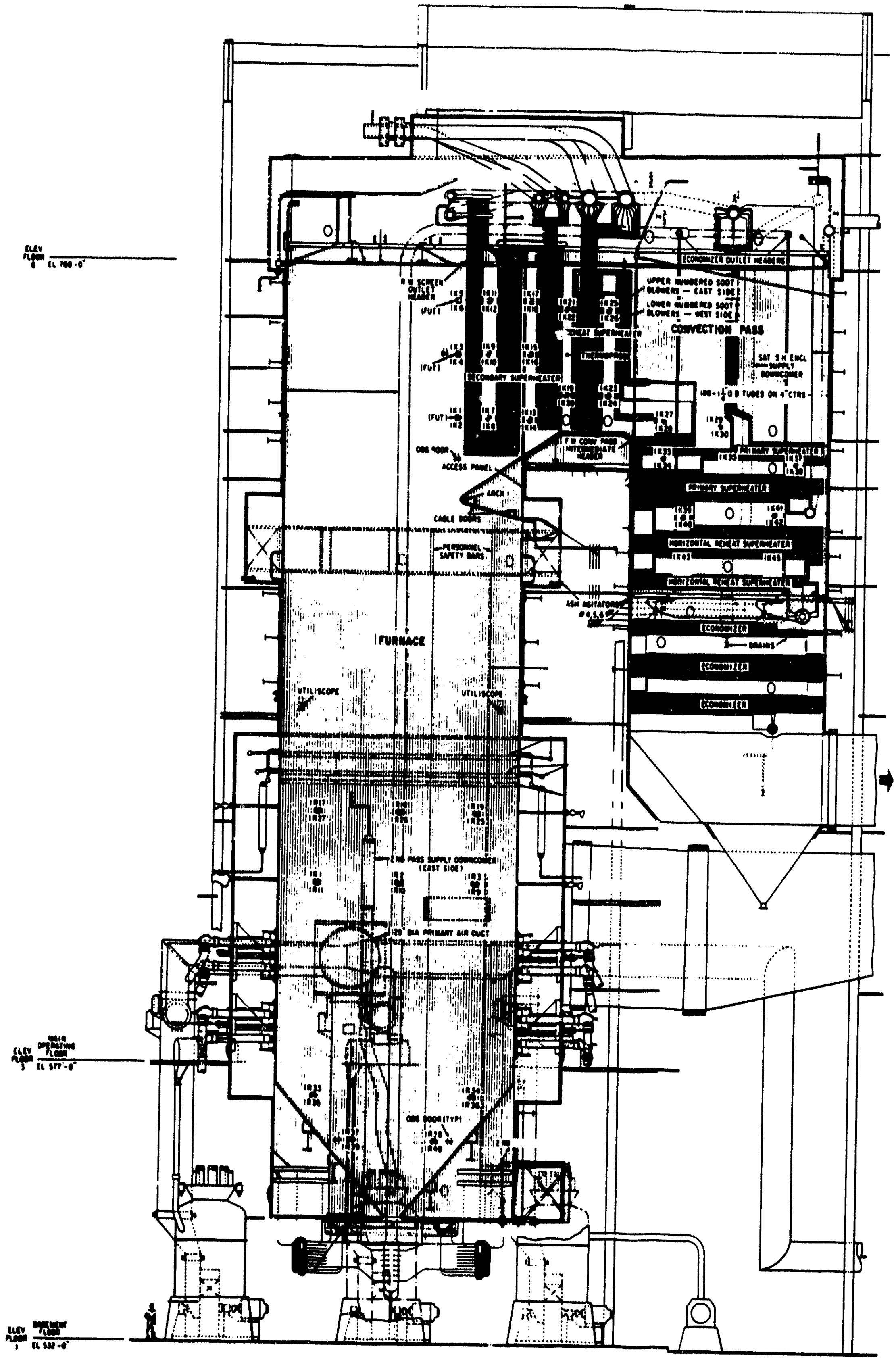

Fig. 12 DP&L J.M. Stuart Station Unit No. 4.

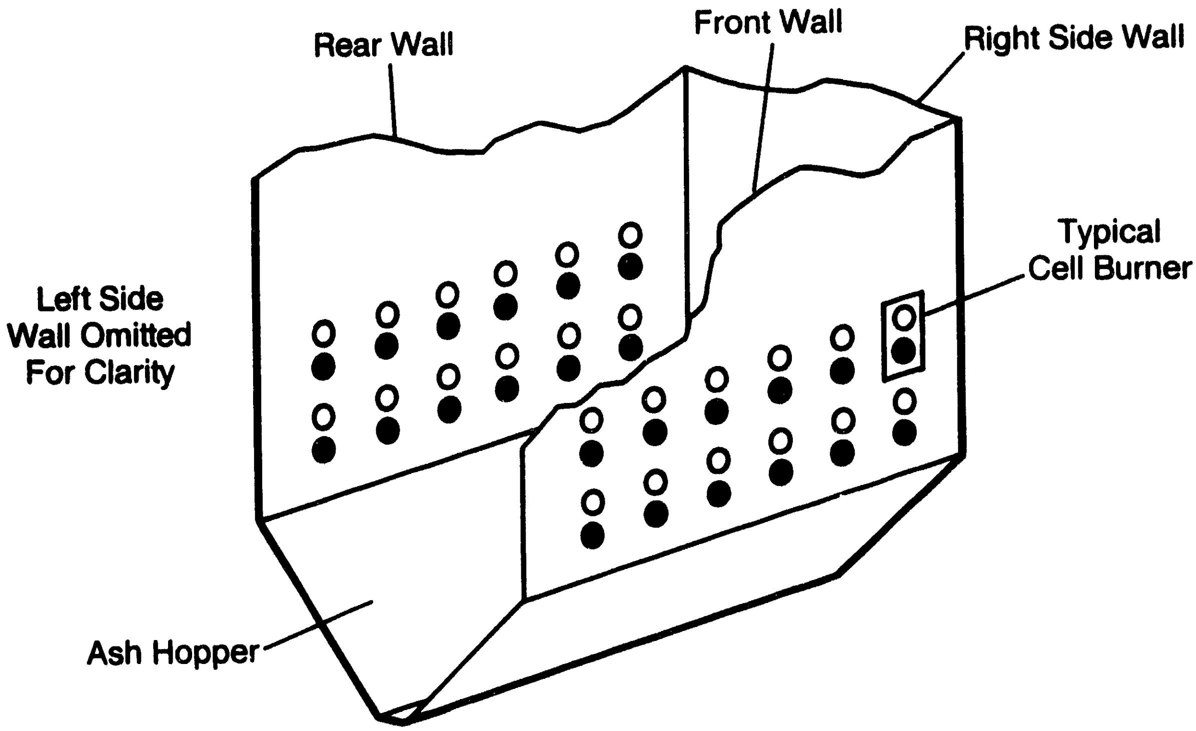

Fig. 13 Original LNCB™ arrangement.

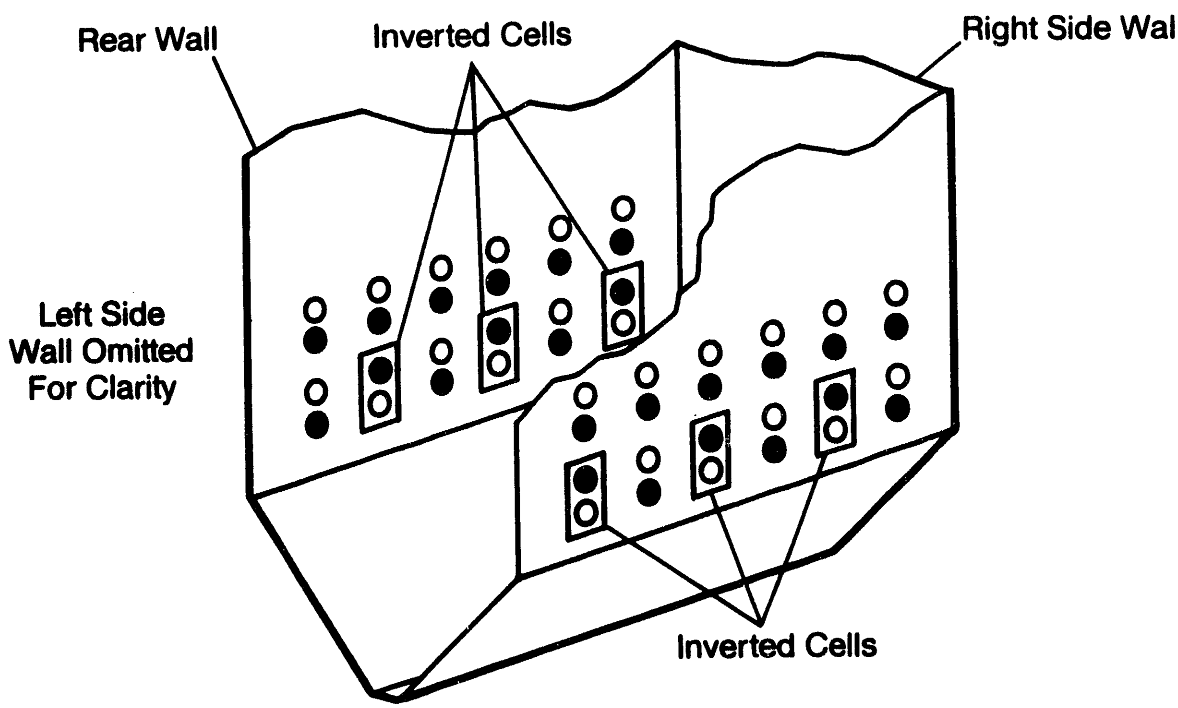

Fig. 14 Partially inverted LNCB™ arrangement.

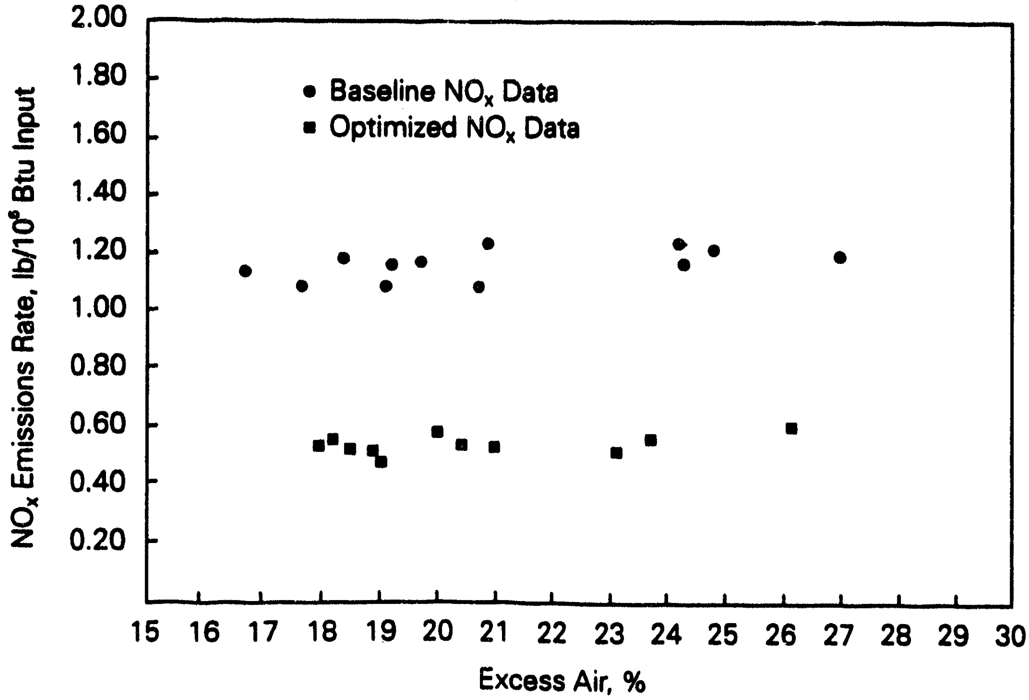

Fig. 15 LNCB™ baseline and retrofit NO_x emissions data as a function of excess air.

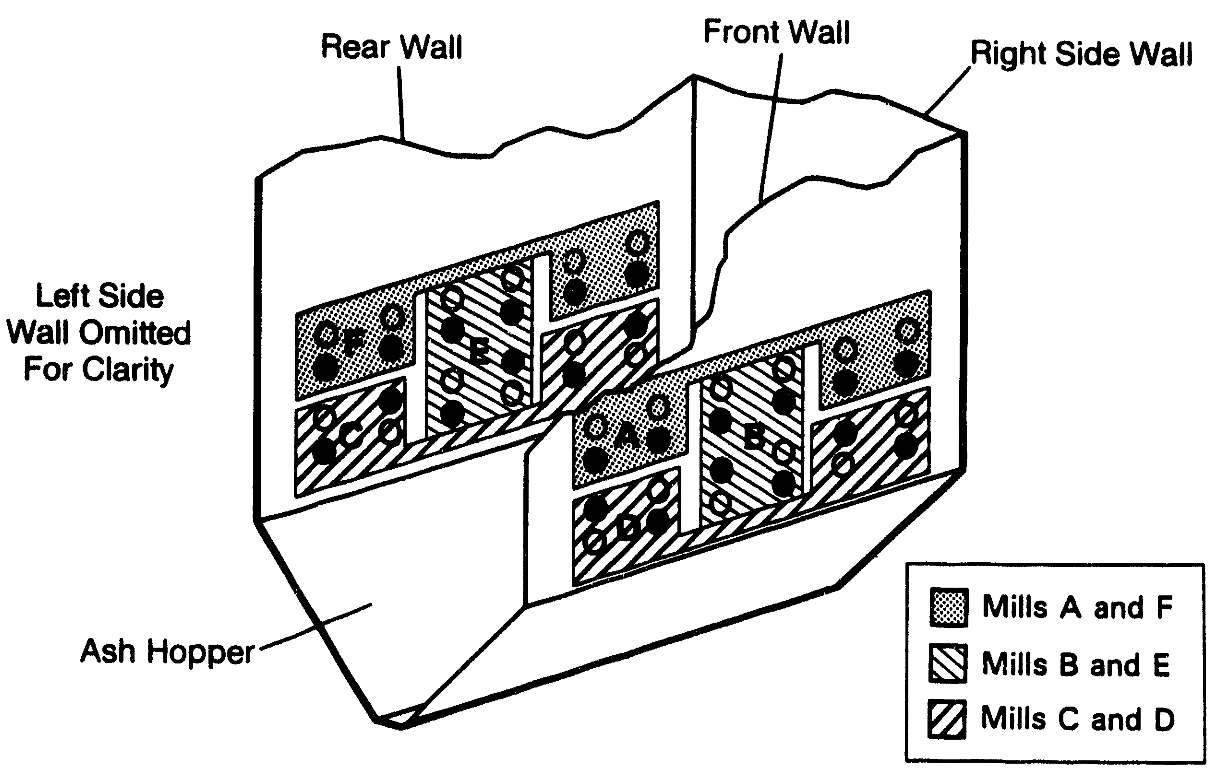

Fig. 16 Revised LNCB™ arrangement with burner/mill combinations.

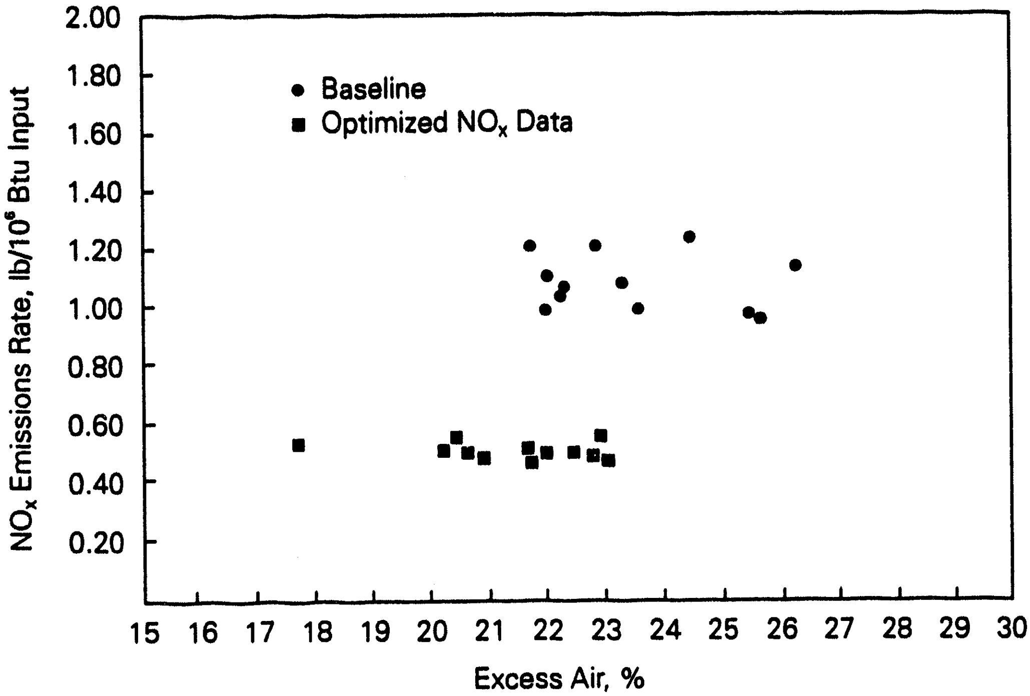

Fig. 17 LNCB™ NO_x emissions data for full load, five mills in service.

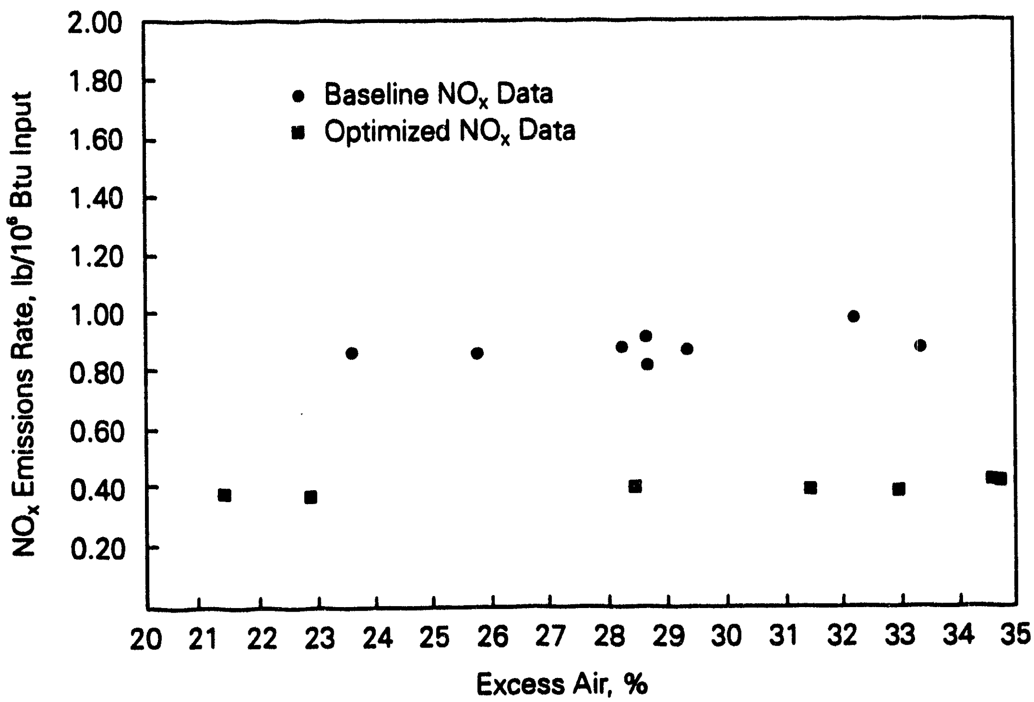

Fig. 18 LNCB™ NO_x emissions data for intermediate (75%) load, 5 mills in service.

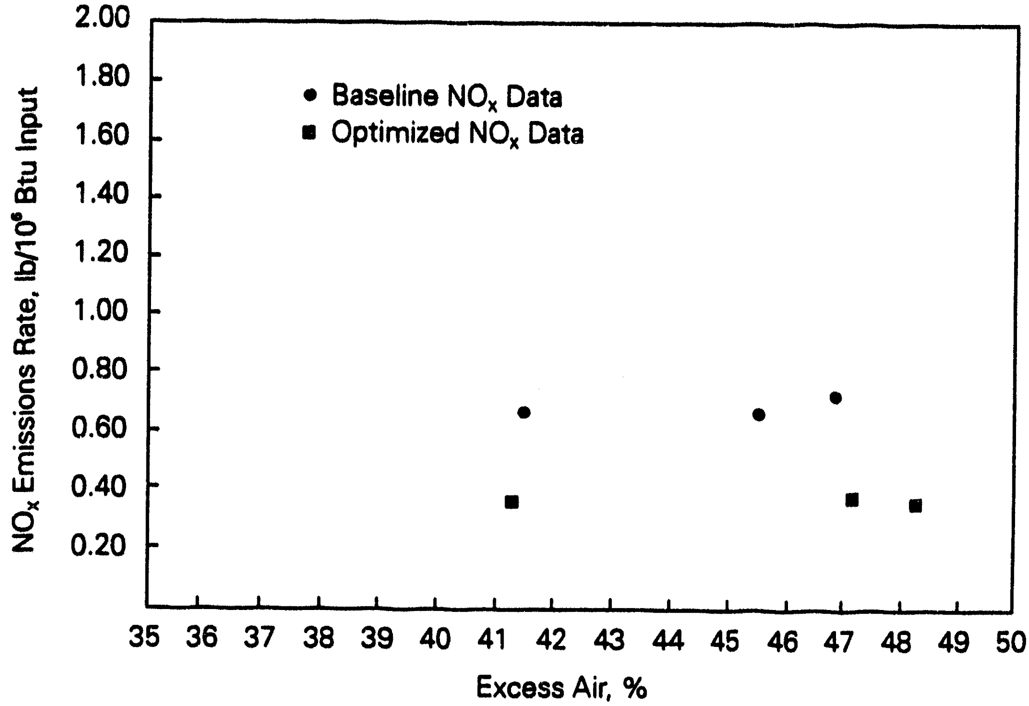

Fig. 19 LNCB™ NO_x emissions data for low (54%) load, 4 mills in service.

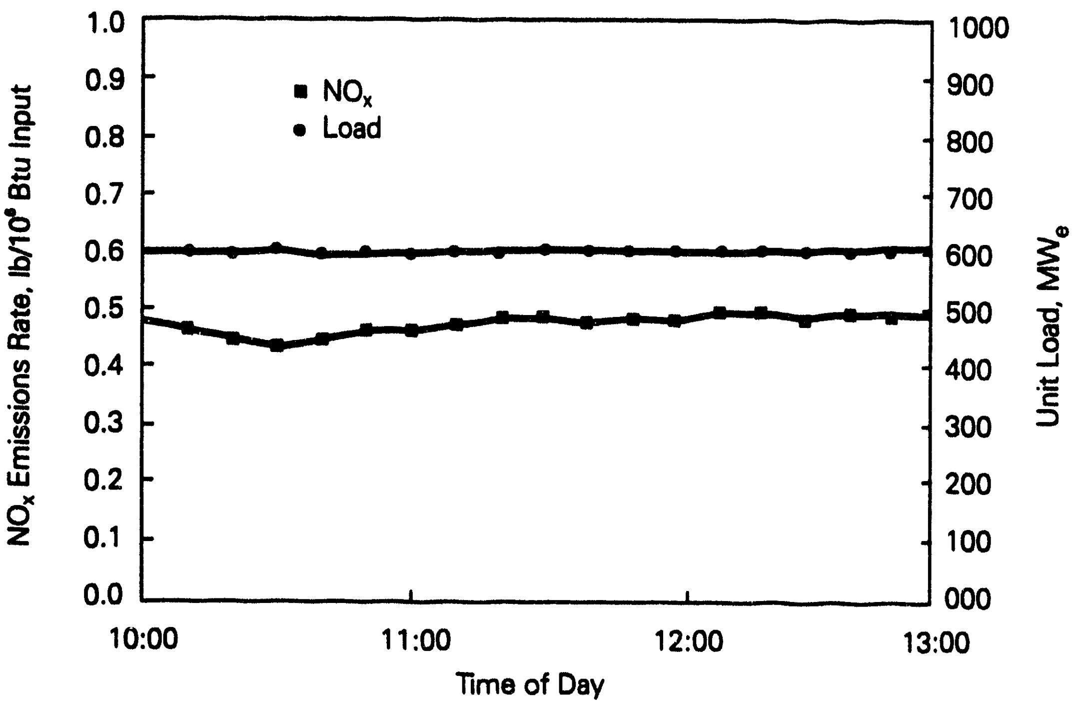

Fig. 20 LNCB™ one-day test results, March 1, 1993.

Energy and Environmental Research Corporation

Technical Paper

GAS REBURNING AND LOW NO_x BURNERS ON A WALL-FIRED BOILER

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ABSTRACT

Parametric tests were conducted for a Gas Reburning-Low NO_x Burner system on a 172 MWe (gross) wall-fired boiler. At 150 MWe net load, the initial low NO_x burner design reduced NO_x emissions from 0.73 lb/10^6 Btu (314 mg/MJ) to 0.50 lb/10^6 Btu (215 mg/MJ), a 31 percent overall reduction. At the same net load, with Gas Reburning-Low NO_x Burner operation using 20 percent of total heat input provided by natural gas, NO_x emissions were reduced further to 0.20 lb/10^6 Btu (86 mg/MJ), a 72 percent overall reduction. These short-term NO_x emissions remained fairly constant when gas heat input ranged from 16 to 23 percent. NO_x emissions decreased linearly with decreasing excess air level at the boiler exit. At baseline or pre-LNB, GR conditions, CO was less than 200 ppm. Baseline carbon loss was less than 6 percent carbon in the ash. The Gas Reburning-Low NO_x Burners operation and the Low NO_x Burners operation produced CO and carbon in ash in these ranges. The heat rate was increased by about 1 percent in the Gas Reburning-Low NO_x Burner operation. Long-term demonstration testing based on automatic, load-following operation started in April 1993 and initial long-term NO_x results agreed with the parametric test results at the same excess air levels.

INTRODUCTION

A Gas Reburning system combined with low NO_x burners was installed and is being evaluated on a 172 MWe (gross) wall-fired utility boiler. The objective of this project [1] is to demonstrate that the combination of Gas Reburning (GR) and low NO_x burners (LNB) will achieve 70 to 75 percent NO_x reduction. This $16.2 million project is a Clean Coal Technology III program sponsored by the U.S. Department of Energy, Gas Research Institute, Public Service Company of Colorado, Colorado Interstate Gas, Electric Power Research Institute, and Energy and Environmental Research Corporation (EER). The GR system including an overfire air system was designed and installed by EER. The LNB system was designed and installed by Foster Wheeler. The parametric testing of the GR-LNB system has been completed. Long-term demonstration testing of the system is currently in progress to determine its impacts on the boiler and boiler operation.

With GR about 80 to 85 percent of the primary fuel is fired in the primary burner zone. The balance of the heat input is provided downstream by natural gas. The gas is injected into the furnace above the primary coal burner zone to produce a slightly fuel-rich zone where NO_x produced by the coal combustion is "reburned" and reduced to atmospheric nitrogen. Combustion is completed by the addition of overfire air (OFA). GR also reduces SO_2, particulates, and CO_2 (a greenhouse gas) by about 20, 20, and 8 percent, respectively, as a result of 20 percent substitution of the heat input by natural gas. This is because natural gas does not contain sulfur or ash and has a higher hydrogen/carbon ratio than coal. The level of NO_x reduction achievable with GR using 15 to 20 percent natural gas is approximately 50 to 60 percent. The NO_x reduction goal for the combination of GR and LNB technologies is 70 to 75 percent.

The host boiler for the project is Cherokee Station Unit 3 at Denver, Colorado. It is owned and operated by Public Service Company of Colorado (PSCO). The unit fires Colorado bituminous coals. The LNB system consists of 16 Foster Wheeler Internal Fuel Staging burners.

This paper describes the boiler, GR-LNB technology, parametric test results, and initial long-term test results.

BOILER DESCRIPTION

Cherokee Station Unit 3 is a 172 MWe (gross) front wall-fired electric facility (Figure 1) located in Adams County, Colorado. The boiler is a balanced-draft pulverized-coal unit supplied by Babcock & Wilcox. As the demand load for the station rises, load on each of four units increases proportionally. Individual units are loaded incrementally based upon current heat rates. The capacity factor and swing load conditions allow evaluation of GR-LNB performance over a wide range of boiler operating conditions with minimal impact on normal plant operations.

Low-sulfur coal (typically 0.4 percent sulfur) is fed to four Riley Stoker No. 556 duplex drum type coal breaker and pulverizing mills, each having a maximum capacity of 37,000 lb/hr (16,800 kg/hr). Coal fed to the mills is pulverized so that at least 70 percent will pass through 74 micron openings (a 200 mesh U.S.S. sieve) and at least 98.5 percent will pass through 297 micron openings (a 50 mesh U.S.S. sieve).

The pulverized coal is transported to a 4x4 array of Foster Wheeler Internal Fuel Staging low NO_x burners, located on the front wall of the boiler. The radiant zone is 24 ft (7.3m) deep and 42 ft (12.8m) wide and has a full division wall. At the original full load, the design heat input is 1.65×10^9 Btu/hr (1,740 GJ/hr). Natural gas was available at the plant prior to the project. Baghouses are used to control particulate emissions to less than 0.1 lb/10^6 Btu (43 mg/MJ).

GR-LNB TECHNOLOGY

The combined GR-LNB system[2] is shown schematically in Figure 2. Several recent references on gas reburning are available [3]-[10].

Low NO_x Burners

Sixteen Foster Wheeler Internal Fuel Staging low NO_x burners replaced the Babcock & Wilcox circular-type PL burners. The LNBs employ dual combustion air registers which allow for control of air distribution at the burner, providing independent control of the ignition zone and flame shaping. These are designed to achieve a goal of 45 percent reduction of NO_x at 150 MWe (net) relative to the nominal baseline emission of 0.73 lb/10^6 Btu (314 mg/MJ) at 20 percent excess air or 3.5 percent O_2 on a dry basis.

Gas Reburning System

Natural gas, the reburning fuel, is injected together with recirculated flue gas (FGR) through sixteen 5.5 inch (14.0 cm) diameter front and rear wall nozzles - eight located on each wall. Approximately 3.4 percent of the flue gas is injected through the gas reburning nozzles to improve mixing of natural gas and dispersion within the furnace. This configuration provides for adequate wall to wall and lateral dispersion. The nozzle exit velocity varies linearly with boiler load, ranging from about 90 ft/sec (27.4 m/s) at 50 percent load to 180 ft/sec (54.9 m/s) at 100 percent load. At full load, the required velocity head for the composite nozzles is 4 inches (10.2 cm) of water column. The range of design flow rates of natural gas is 10 to 25 percent of the total heat input. The natural gas is transported by means of the flue gas constituting 3 to 4 percent of the total flue gas and injected through ports above the upper row of burners. The injection velocity is kept low to minimize furnace flow disruption.

Overfire Air

Overfire air is injected into the furnace through six 20.5 inch (52.1 cm) diameter injectors located on the front wall of the furnace. The injectors are tilted downward 10 degrees to improve overfire air dispersion and to increase residence time. The amount of air added at this point is to complete burning of residual natural gas and bring excess air levels to non-GR values.

Operation

To begin operation of the GR system, the operator first starts the overfire air booster fan. Then the overfire air flow is increased until the desired primary burner zone stoichiometry (Figure 2) is achieved. After selecting a reburning zone stoichiometry, natural gas flow is manually initiated and then switched to automatic control of gas reburning. To shut down the GR system, the operator reverses these steps. While the system is being shut down, cooling air is fed through all GR nozzles.

Safety System

The GR system functions independently of the boiler in that a GR system trip will not trip the boiler. Interlocks are designed to start the GR equipment in an orderly fashion and prevent the operator from allowing the unit's safety to become compromised either through erroneous operation or due to equipment failure. All major commands issued by the control system are verified by a feedback signal. Trip signals are continuously monitored by the control system and will prevent startup or shutdown equipment already in operation.

The GR process does not produce a luminous flame capable of being sensed by conventional flame scanners. To insure that natural gas is not injected into a cold furnace, 8 flame scanners monitor the presence of main fuel flames in the boiler. Loss of signal from 4 scanners automatically shuts down the GR system.

STOICHIOMETRIC RATIOS

The GR process (Figure 2) can be best described by considering three combustion zones in series:

- Primary burner zone: approximately 80-85 percent of the heat is released by coal in this zone under low excess air conditions, achieving a small reduction of NO_x.
- Reburning zone: the reburning fuel, in this case natural gas (normally 15 to 20 percent of the total heat input), is injected downstream of the primary burner zone in the upper furnace to create a slightly fuel-rich zone where NO_x is reduced to elemental N_2.
- Burnout zone: in the third and final zone, additional combustion air (overfire air or OFA) is added to burn any remaining fuel fragments and complete the combustion process.

Each of the three zones in Figure 2 has its unique stoichiometric ratio (SR). The three SR values can be calculated from the following equations:

Primary Burner Zone $$SR_1 = \frac{TA - OFA}{CSA} \quad (1)$$

Reburning Zone $$SR_2 = \frac{TA - OFA}{CSA + GSA} \quad (2)$$

Burnout Zone $$SR_3 = \frac{TA}{CSA + GSA} \quad (3)$$

The symbols used in these equations are defined as follows:

TA = Total air, scfm or Nm^3/s

OFA = Overfire air, scfm or Nm^3/s

CSA = Coal stoichiometric air, scfm or Nm^3/s

GSA = Natural gas stoichiometric air, scfm or Nm^3/s

Since there are seven variables in three equations, only four variables are independent variables.

PARAMETRIC TEST RESULTS

The parametric tests were conducted by changing the process variables, such as zone stoichiometries, percent gas input, percent overfire air, FGR, load, etc. The effects of these variables on NO_x reduction, SO_2 reduction, CO emissions, carbon in ash, and heat rate were studied. At full load, the boiler is normally operated with four coal pulverizing mills. Each mill supplies coal to one row of four burners. In the gas reburning operation using natural gas as a reburning fuel at 20 percent of the total heat input, the boiler can be operated with three mills even at full load.

Typical Operation Profile

A typical operation profile is shown in Figure 3. At a constant load (150 MWe) and a constant O_2 level at the boiler exit (not shown in diagram), both NO_x and SO_2 emissions decrease when natural gas is introduced in the GR operation. If natural gas supply is discontinued, NO_x and SO_2 emissions increase, as expected. A similar trend is exhibited by NO_x and SO_2 emissions at 120 MWe. When the load is decreased from 150 to 120 MWe, NO_x emission decreases but SO_2 emission in $lb/10^6$ Btu (or mg/MJ) remains unchanged since the latter is dependent only on the sulfur content of coal.

Effect of Stoichiometry

Over several months, extensive parametric tests of GR have been completed at Cherokee. Figure 4 shows the results as a function of zone stoichiometry. For the baseline and LNB tests, which involve a single combustion zone, the stoichiometry is the overall stoichiometry. For GR-LNB, the stoichiometry refers to the reburning zone. Table 1 shows the NO_x results of the parametric tests. For the baseline and LNBs, the table presents data for 20 percent excess air. For GR-LNB, the table presents data for the minimum NO_x level, at a reburning zone stoichiometry of 88 percent of theoretical air. At this point, the gas heat input was 20 percent. The minimum NO_x emission with GR-LNB measured to date was 0.20 lb/10^6 Btu (86 mg/MJ). This corresponds to a NO_x reduction of 72 percent from baseline levels and 60 percent reduction from using only the low NO_x burners.

As listed in Table 1, present NO_x reduction with LNB operation is 31 percent. Foster Wheeler plans to make burner revisions during the planned January, 1994 boiler outage to achieve the goal of 45 percent NO_x reduction.

TABLE 1

NO_x Data from Cherokee Unit 3: Parametric Tests

Firing Configuration	NO_x Emissions lb/10^6 Btu	(mg/MJ)	NO_x Reduction (%) Relative to: Baseline	Low NO_x Burners
Baseline	0.73	(314)	0	NA
Low NO_x Burners (initial design)	0.50	(215)	31	0
Gas Reburning and Low NO_x Burners	0.20	(86)	72	60

Effect of Excess Air

Figure 5 shows NO_x emissions vs. percent O_2 dry at the boiler exit. A linear relationship was obtained between NO_x and O_2 for baseline, LNB, and GR-LNB.

Effect of Gas Heat Input

In general, the NO_x emission is reduced with increasing gas heat input, as shown in Figure 6. At gas heat inputs greater than 10 percent, the NO_x emission is reduced marginally with increasing gas heat input. It looks like that 10 percent gas heat input is optimal for NO_x reduction per unit gas heat input.

Natural gas also reduces SO_2 emissions in proportion to the gas input. At Cherokee Station, low sulfur coal is used and the typical SO_2 emissions are 0.65 lb/10^6 Btu (280 mg/MJ). With a gas heat input of 20 percent, SO_2 emissions are decreased by 20 percent to 0.52 lb/10^6 Btu (224 mg/MJ), as expected from fuel substitution by natural gas essentially free from sulfur.

The CO_2 emission is also reduced as a result of using natural gas because natural gas has a lower carbon/hydrogen ratio than coal. At Cherokee, CO_2 emissions from typical coal and natural gas combustion are 210 lb/10^6 Btu (90.3 g/MJ) and 120 lb/10^6 Btu (51.6 g/MJ), respectively. At a gas input of 20 percent, the CO_2 emission is reduced by 8 percent.

Effect of Load

The effect of load on NO_x is shown in Figure 7. For baseline, LNB, and GR-LNB, the NO_x emission increases with increasing load. The increase in NO_x with increasing load is more moderate with GR-LNB than that with baseline or LNB as indicated by the slopes of the curves.

CO Emissions and Carbon Loss

Baseline CO is less than 200 ppm. Baseline carbon loss is less than 6 percent carbon in ash. Both baseline CO and baseline carbon loss decrease with increasing excess air level at the boiler exit. The CO and carbon are converted to CO_2 more readily at a higher excess air level. Both LNB and GR-LNB produced CO and carbon in ash in these ranges under similar or lower excess air conditions.

Heat Rate

The factors that affect the heat rate are

- Carbon loss
- Dry gas loss (related to excess air and boiler exit temperature)
- Latent heat loss (related to H_2O in the combustion products)
- Steam temperature (affecting turbine cycle efficiency)
- Auxiliary power

The carbon loss remains unchanged with GR operation. The dry gas loss is essentially unaffected because an increase of about 10°F (6°C) in boiler exit temperature is canceled out by a reduction in excess air. The latent heat loss reduces the boiler efficiency by about 1 percent when using 20 percent gas heat input. The steam temperature can be maintained via attemperation. The slight increase in auxiliary power use is offset by the reduced mill power. Overall, the heat rate increased about 1 percent.

Data Prediction

Based on the parametric test results, the BrainMaker (a neural network that can "learn" from experience and make predictions) predicted NO_x levels which agreed with measured NO_x levels during the long-term testing, as shown in Figure 8. The four major independent process variables used in the BrainMaker for NO_x prediction are load, CEMS O_2, gas heat input, and reburning zone stoichiometry (SR_2) for LNB, LNB-OFA, and GR-LNB operations.

LONG-TERM TESTING

Long-term testing started in the last week of April, 1993 and will last for one year. The objective of the testing is to obtain operating data over an extended period when the unit is under routine normal commercial service, determine the effect of GR-LNB operation on the unit and obtain the incremental maintenance and operating costs with GR.

Operating Data

The nominal long-term testing conditions specified are a primary burner zone stoichiometry of 1.08, a burnout zone stoichiometry of 1.18, a gas heat input of 18 percent, and the FGR flow rate of 10,000 scfm (4.7 Nm^3/s), based on the parametric test results. However, the gas heat input will be lowered to 10 percent or so during some periods of the long-term testing.

The initial long-term test results obtained in the first three months agreed with the parametric test results. The long-term data fall on the same curves of NO_x vs. CEMS O_2 (O_2 dry measured with a Continuous Emissions Monitoring System at the boiler exit) and NO_x vs. load in Figures 5 and 7.

Average NO_x reductions (based on the pre-LNB baseline NO_x level of 0.73 lb/10^6 Btu or 314 mg/MJ) and CEMS O_2 levels in various tests are plotted against test dates in Figure 9. It is seen that the NO_x reduction curve is essentially a mirror image of the CEMS O_2 curve. This means that a higher NO_x reduction is achieved at a lower CEMS O_2, as also shown in Figure 5. As usual, it is necessary to maintain CEMS O_2 at or slightly less than 3% O_2 on a dry basis to achieve the greatest NO_x reduction. However, if the CEMS O_2 level is too low, CO will increase exponentially. The average long-term NO_x reduction achieved to date is 64% (ranging from 54% to 72%), reflecting the variability in CEMS O_2. This variability, in turn, is a result of boiler operation where O_2 is controlled manually.

Costs Data

Maintenance and operating costs associated with the GR operation will be obtained over the testing period. While equipment costs can be determined to a fairly precise level, only operation of the system can establish operating and maintenance costs. Accordingly, a system has been set up that will gather pertinent cost data over the 12-month testing period.

The GR system was designed on the basis of using 18 to 20 percent natural gas input. Parametric testing has shown substantial NO_x reduction at 10 percent natural gas input. As the size of GR equipment will be smaller at 10 percent gas heat input, both capital and operating costs will be lower. The unit will be operated with 10 percent gas input during part of long-term testing.

A preliminary cost estimate indicates that the natural gas cost (in $/ton NO_x removed) in the GR process can be decreased by approximately 30 percent in lowering the gas heat input from 18 to

10 percent. This natural gas cost is estimated at a NO_x reduction ratio of 1:0.8 (based on LNB NO_x) with 18 and 10 percent gas heat inputs.

SUMMARY

1. Parametric tests were conducted for a Gas Reburning-Low NO_x Burner system on a 172 MWe (gross) wall-fired boiler. At 150 MWe net load and 20 percent excess air, NO_x emissions from the wall-fired boiler were reduced from 0.73 lb/10^6 Btu (314 mg/MJ) to 0.50 lb/10^6 Btu (215 mg/MJ) by low NO_x burners (a 31% reduction). NO_x emissions were reduced to 0.20 lb/10^6 Btu (86 mg/MJ) (a 72% overall reduction) by Gas Reburning with 20 percent gas input combined with the low NO_x burners.

2. The NO_x level remained fairly constant when gas input was increased from 16 to 23 percent.

3. NO_x decreased linearly with decreasing excess air level at the boiler exit. With this boiler/burner/fuel combination, the boiler exit excess air must be maintained at 3% O_2 dry or slightly lower to maximize NO_x reduction while maintaining a reasonably low CO level.

4. Baseline CO was less than 200 ppm. Baseline carbon loss was less than 6 percent carbon in ash. The Gas Reburning-Low NO_x Burners operation produced CO and carbon in ash in these ranges.

5. The heat rate was increased by about 1 percent with the gas reburning-low NO_x burner operation.

6. Long-term demonstration test results for NO_x levels obtained to date at constant or variable loads are in good agreement with parametric test results at the comparable excess air levels.

7. The BrainMaker program can predict NO_x levels within experimental errors after having been trained with data points.

8. The average NO_x reduction obtained to date in long-term testing is 64%, compared to 70% as the goal. The lower NO_x reduction value is a result of the variability in CEMS O_2 largely due to the manual operation of the boiler.

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The following personnel are acknowledged for their direct technical involvement in the project: EER test personnel led by M. Light, and M. Browning-Sletten, C. Bomberger, and E. Rindahl of Public Service Company of Colorado.

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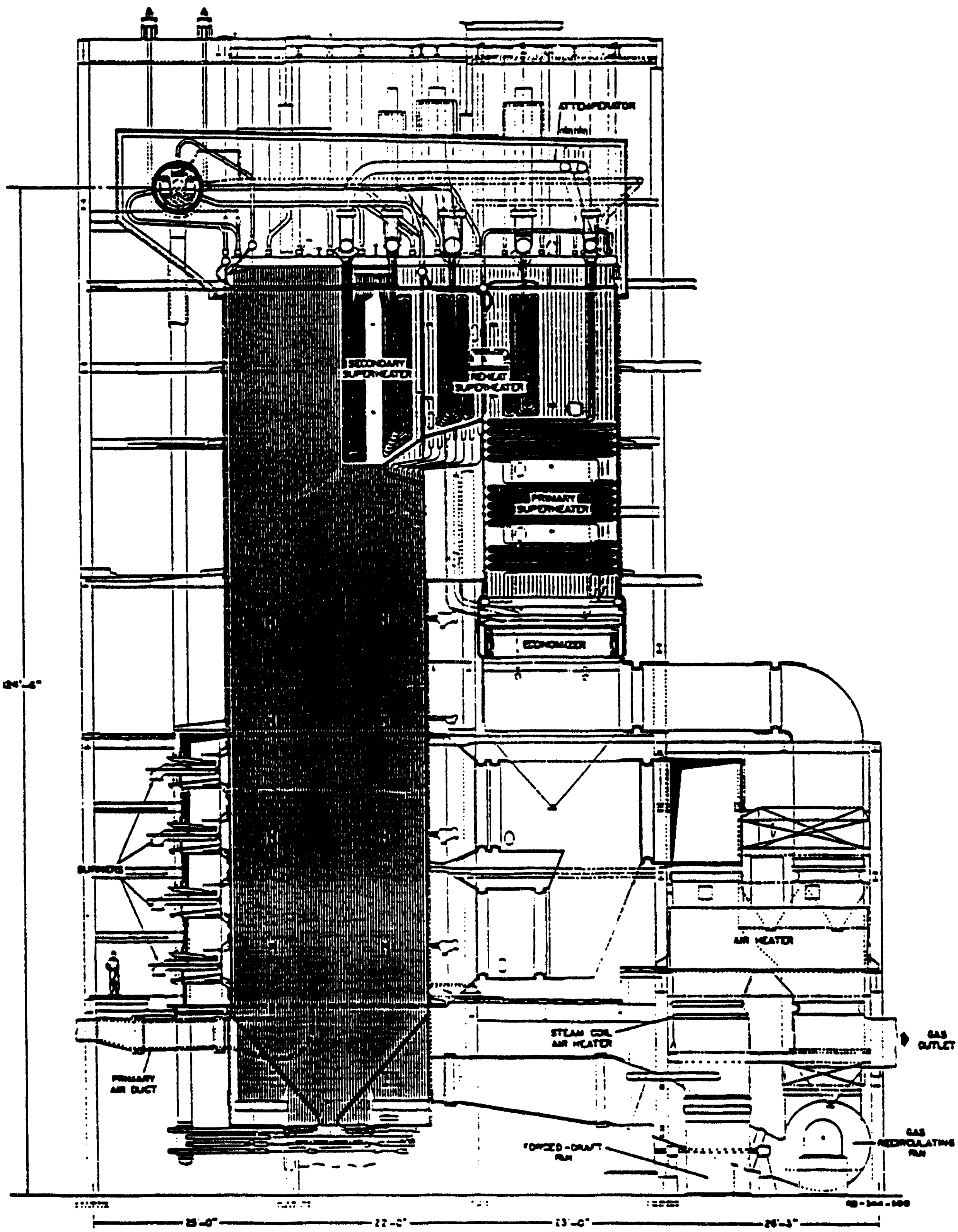

Figure 1. Schematic of Cherokee unit number 3 boiler.

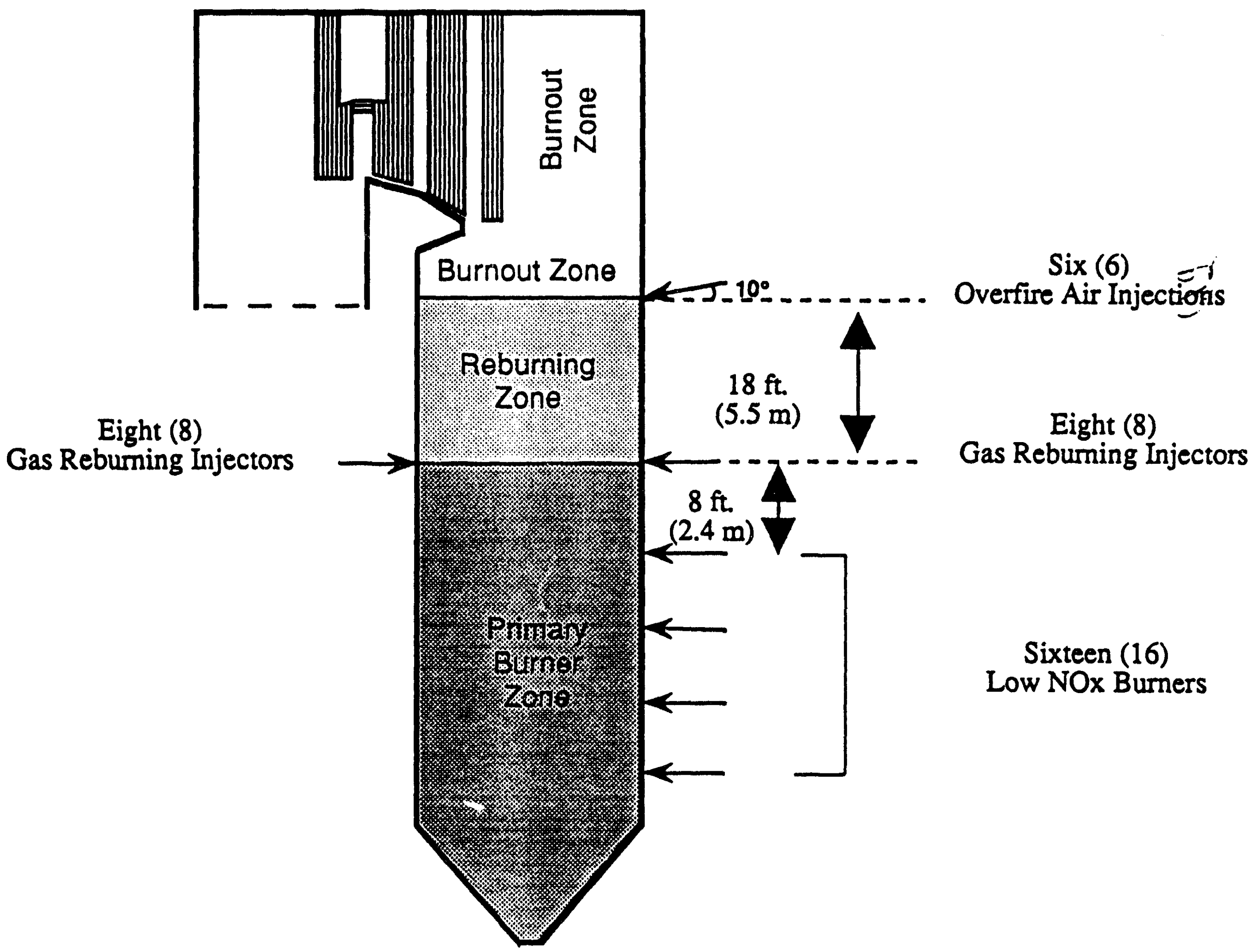

Figure 2. GR-LNB system schematic at Cherokee.

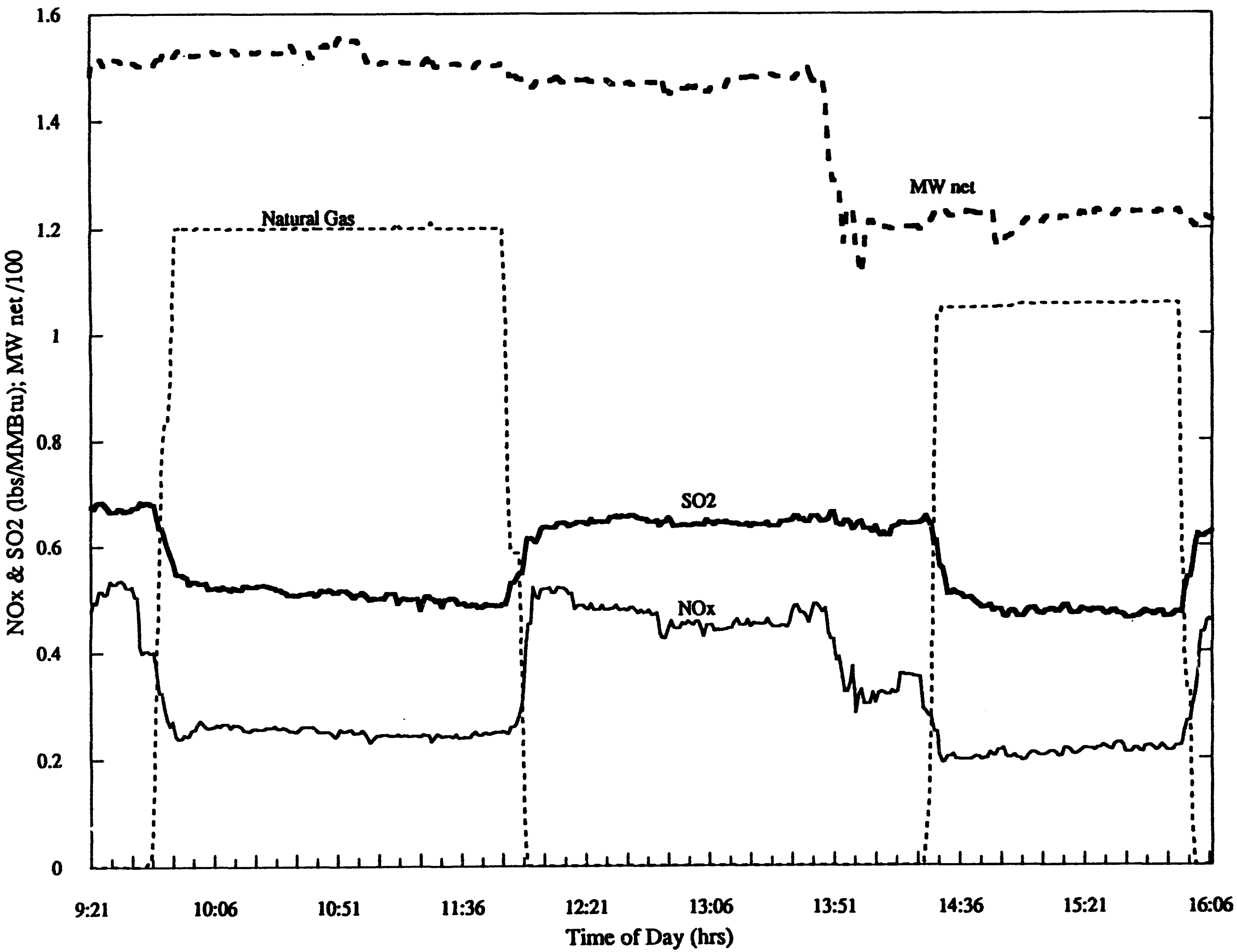

Figure 3. Typical operation profile (1 lb/MMBtu = 430 mg/MJ, MMBtu and MJ based on gross or higher heating values, 1 scfm = 4.72×10^{-4} Nm^3/s).

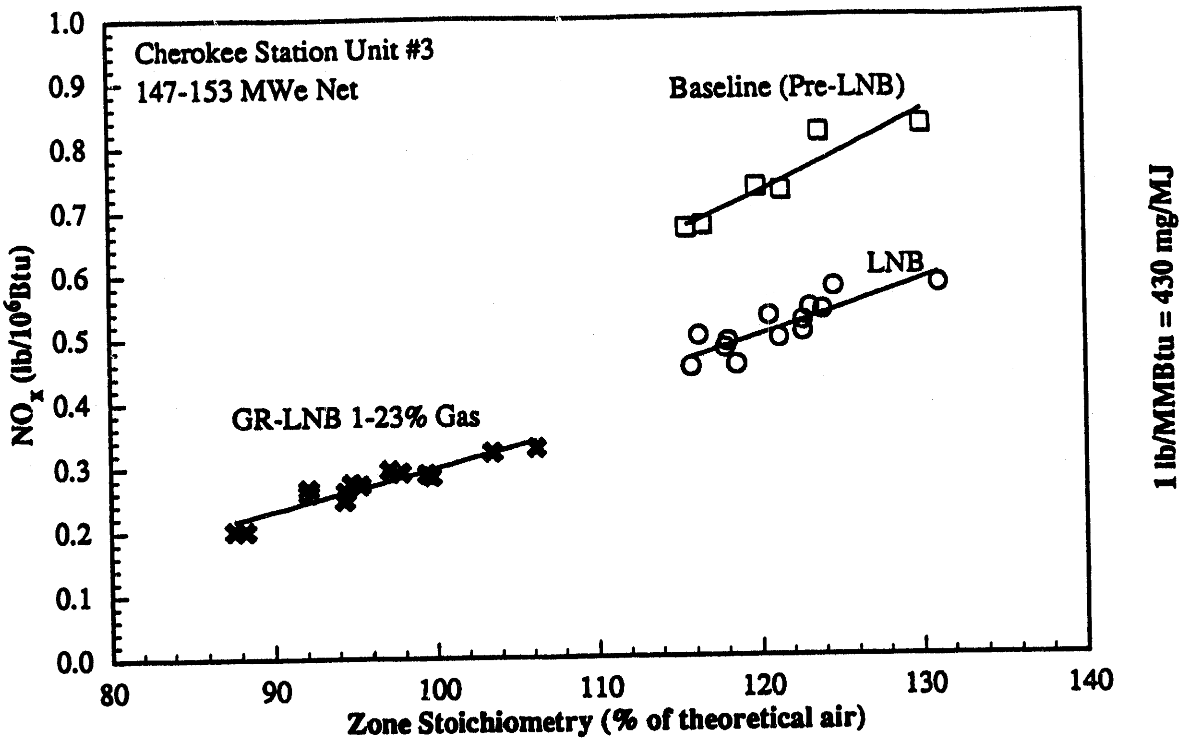

Figure 4. Gas reburning data from Cherokee.

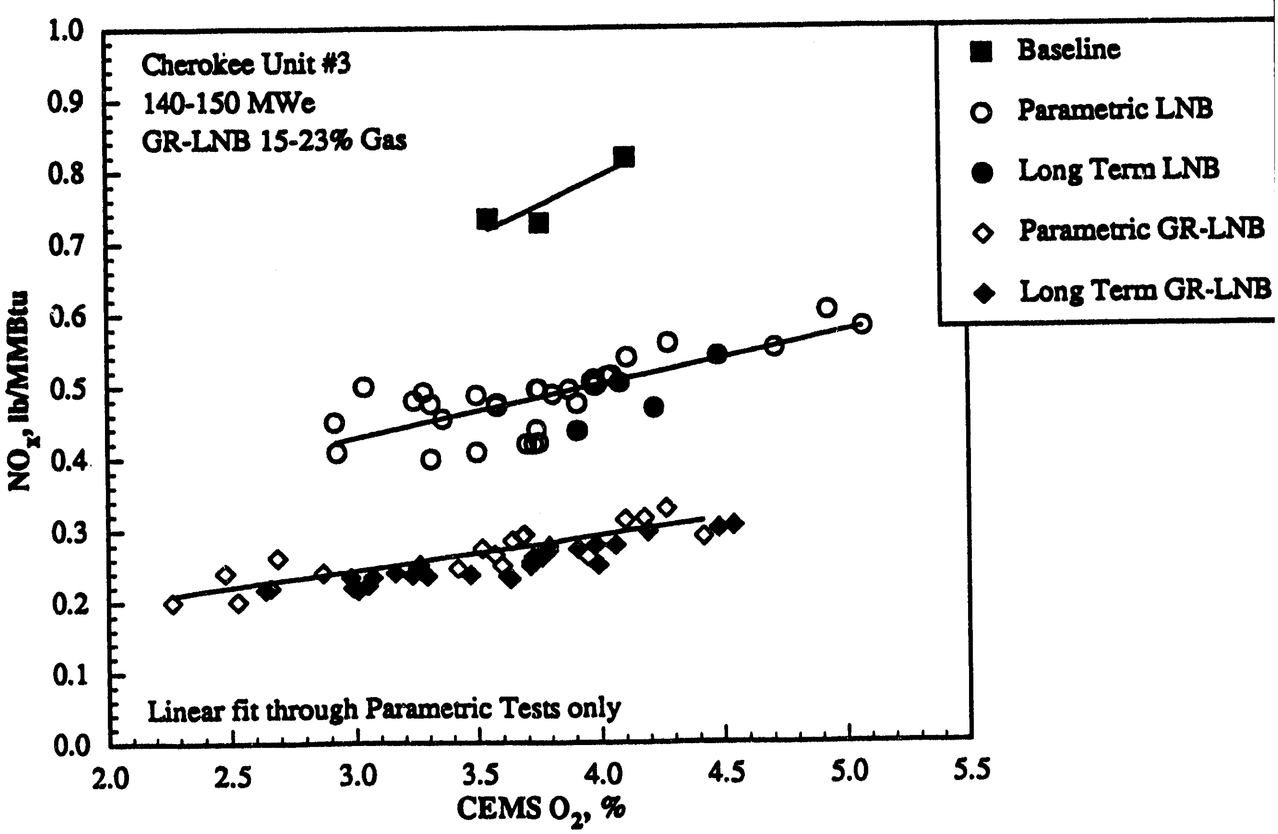

Figure 5. Effect of excess air on NOx.

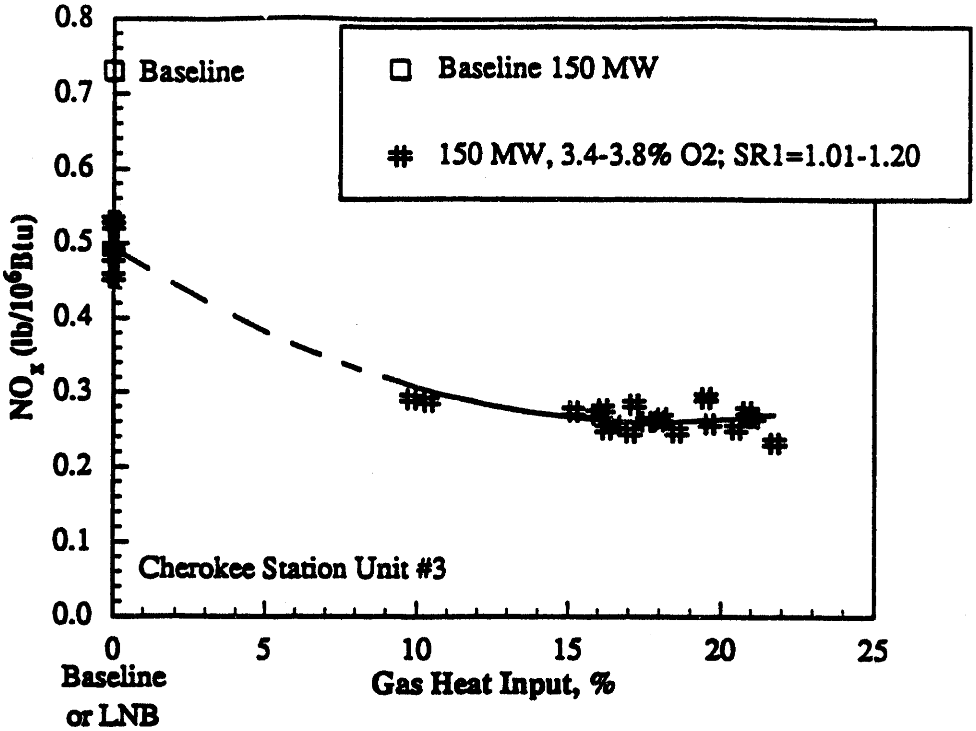

Figure 6. Effect of gas inupt on NO$_x$.

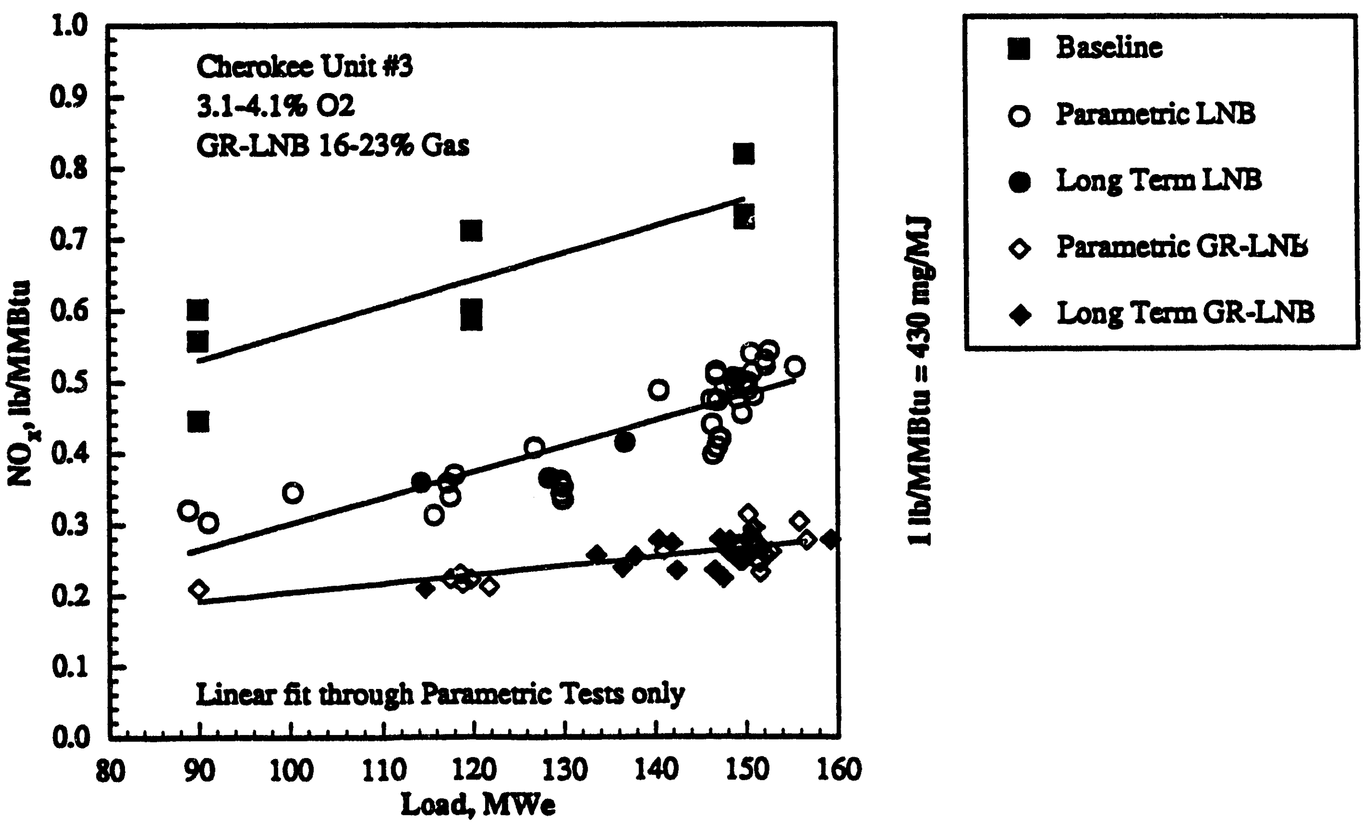

Figure 7. Effect of load on NO$_x$.

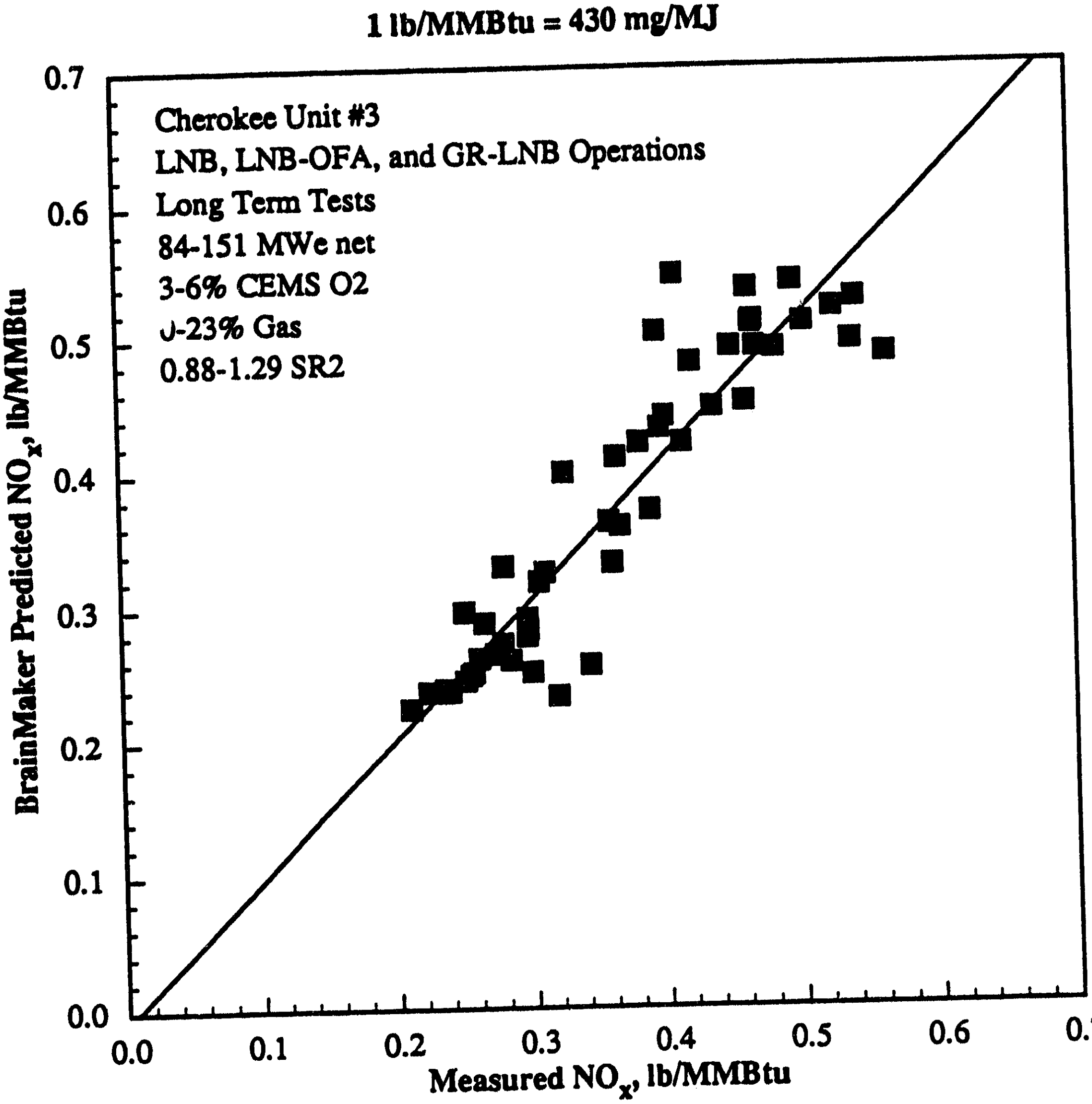

Figure 8. Predicted NO_x vs. measured NO_x.

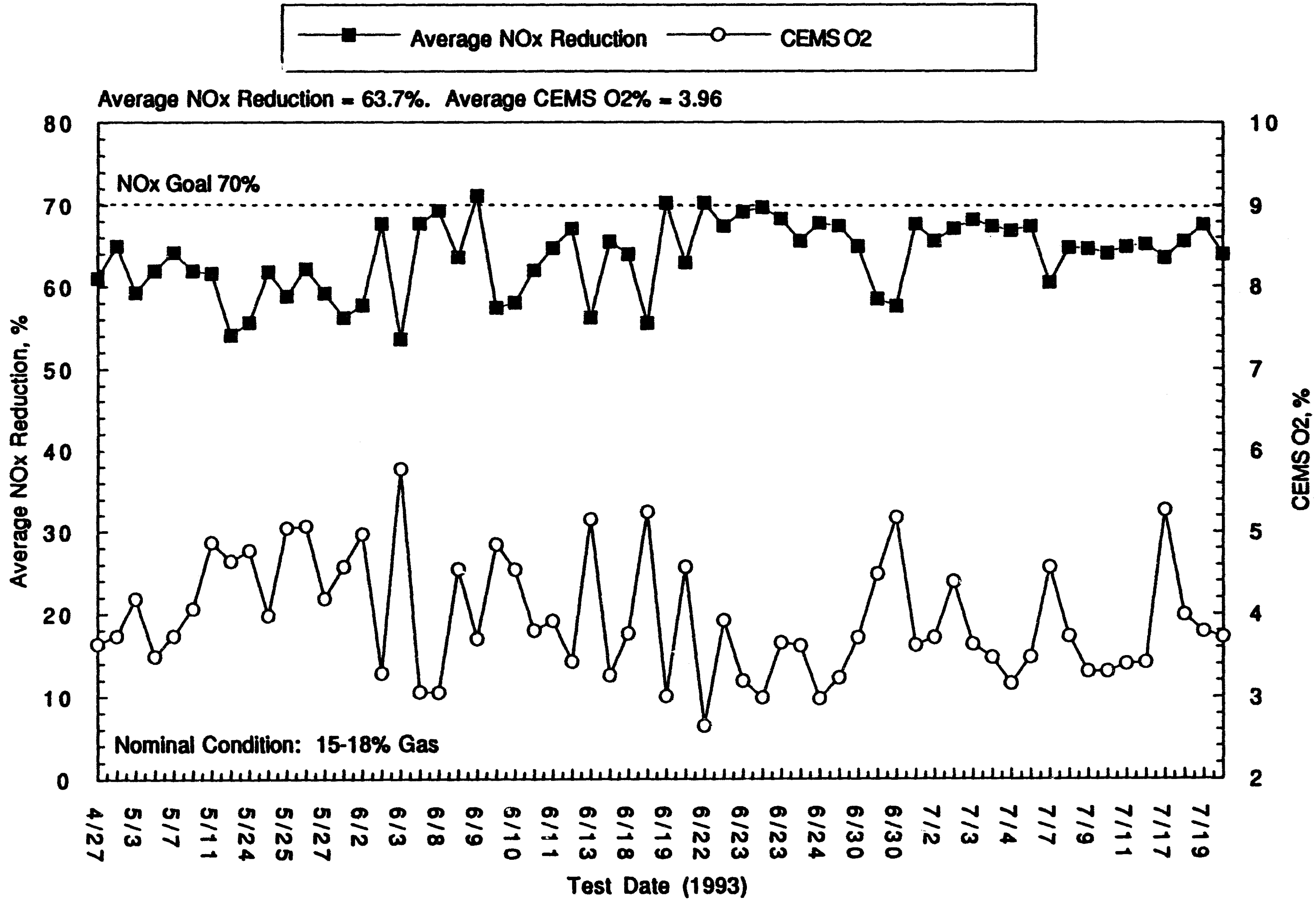

Figure 9. Long term GR-LNB test performance at Cherokee.