MILLIKEN CLEAN COAL TECHNOLOGY DEMONSTRATION PROJECT

MICRONIZED COAL REBURNING DEMONSTRATION FOR NOx CONTROL

FINAL REPORT

COOPERATIVE AGREEMENT DE-FC22-93PC92642

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ABSTRACT

Micronized coal reburning (MCR) was successfully demonstrated at the New York State Electric & Gas Corporation Milliken Station in Lansing, NY and at the Eastman Kodak Company, Kodak Park Boiler #15 in Rochester, NY. The demonstration at Milliken was on a 150 MWe tangentially(T)-fired burner and at Kodak on a 60 MWe cyclone-fired burner. This allowed for the evaluation of the MCR technology on two different, widely used coal-firing commercial units. NOx reductions of 28% at Milliken Station and 57% at Kodak were achieved. Projected capital cost based on the experience gained in this program for a generic 300 MWe T-fired boiler is $14.30/kW and for a generic 300 MWe cyclone-fired boiler is $56.30/kW. The program was funded under a cooperative agreement (DE-FC22-93PC92642) between the U.S. Department of Energy and New York State Electric & Gas Corporation as part of Round 4 of the Department of Energy's Clean Coal Technology program.

Three important conclusions obtained from this work are:

1. Coal reburning was successfully demonstrated without installing a separate reburn system, using existing equipment.

2. Pulverizing the reburn coal to the micronized level (>80% passing 325 mesh) was not a requirement for successful application of reburning.

3. Coal reburning can be applied without a negative impact on fly ash LOI or boiler efficiency.

NOTE: On May 14, 1999, NGE Generation, an affiliate of NYSEG, completed the sale of its coal-fired power plants in New York State, including Milliken Station, to the AES Corporation.

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EXECUTIVE SUMMARY

The Micronized Coal Reburning (MCR) Demonstration for NOx Control project is part of Round 4 of the U.S. Department of Energy Clean Coal Demonstration Program. The project included demonstration of the MCR technology at two sites. At the Eastman Kodak Company cyclone-fired Boiler #15 (60 MWe) located at Kodak Park, Rochester, NY, the technology was demonstrated using a retrofit Fuller MicroMill to produce reburn fuel with greater than 90 wt % less than 43 μm particle size. At the New York State Electric & Gas Milliken Station, in Lansing, NY, MCR technology was demonstrated on a 150 MWe tangentially-fired boiler. An existing DB Riley MPS mill with a dynamic classifier was used to produce the reburn fuel.

The following report gives an overview of the project including history, project organization, site descriptions, and project schedule. A thorough description of the MCR technology and how it was implemented at each of the two demonstration sites is provided. The demonstration tests were made independently at each site. Test plans, operation procedures, analyses of feedstocks, and results of testing are provided for all tests.

MCR technology is a combination of fuel reburning for NOx control with a technology that produces micronized coal reliably and economically. Micronized coal is defined as coal ground to a particle size of 43 μm or smaller. Micronized coal surface area and combustion characteristics are similar to those of atomized oil. The high surface area of micronized coal allows carbon burn-out within milliseconds. Volatiles are released at an even rate over a given temperature range. This uniform, compact combustion envelope permits complete combustion of the coal/air mixture in a smaller furnace volume than is possible with conventional pulverized coal. Heat rate, carbon loss, boiler efficiency, and NOx formation also are impacted by coal particle size. When micronized coal is fired at stoichiometry of 0.8 to 1.0, devolatilization and carbon burn-out occur rapidly. Accurate control of the combustion process is enhanced by the extensive surface area of micronized coal.

MCR tests at the Milliken Station were conducted at full boiler load (140-150 MW) and 14.4% reburn heat input. NOx emissions were reduced from a baseline Low NOx Concentric Firing System 3, (LNCFS-3) of 0.35 to 0.25 lb/MM Btu (28% reduction), while maintaining the fly ash loss on ignition (LOI) below 5%. The boiler efficiency was maintained at 88.4-88.8%. The projected annual NOx emissions using 15.1% coal reburn were 0.245 ± 0.011 lb/MM Btu (95% confidence), corresponding to a fly ash LOI of 4.4% ± 0.4%.

At the Kodak Park site, the micronized coal reburn tests at reburn stoichiometry of 0.89 reduced NOx emissions from a baseline (no reburn) of 1.36 to 0.59 lb/MM Btu (57% reduction), increased the fly ash carbon content from 11% to 37%, and reduced the boiler efficiency from 87.8% to 87.3%. The projected annual NOx emissions were 0.69 ± 0.03 lb/MM Btu (95% confidence), corresponding to a fly ash carbon content of 38% ± 2%. The increase in the fly ash carbon content relative to baseline was partially due to a lower cyclone heat input and partially due to the staged combustion. The contribution of reburning alone (assuming no change in the cyclone heat input) to the increase in the fly ash carbon content was estimated at 0-12% (absolute).

The report also documents the electrostatic precipitator performance under MCR operating conditions at each site. At the Milliken site, MCR did not adversely affect the performance of the electrostatic precipitator, as measured by removal efficiency or penetration, although the carbon content of the fly ash increased from 2.4% to 3.7%. However, the absolute emission rate increased approximately 30% due to the increase in ESP inlet loading brought about because the micronized coal injected for reburn high in the boiler had a short residence time resulting in more unburned material reaching the ESP than baseline levels.

At the Kodak site, the ESP was tested with and without MCR. With MCR, the particulate loadings to the ESP increased 2.8 times the baseline level for the same reason given above for the increased loading to the Milliken ESP. The loading to the stack increased 1.8 times the baseline level. However, the average particulate removal efficiency was greater for MCR than for the baseline. The ESP continued to meet the dust emission performance guarantee.

An economic evaluation of the MCR technology based on the acquired data from the two combustion systems prepared by CONSOL R&D is included. Capital costs for a generic 300 MWe cyclone boiler are projected to be \$56.30/kW and \$14.30/kW for a generic 300 MWe T-fired boiler. Total levelized cost for NOx reduction for the 300 MWe T-fired boiler is \$1023/t NOx removed and \$571/t NOx removed for the 300 MWe cyclone boiler.

Commercialization potential, plans of the participants to utilize MCR technology and general conclusions are offered. The low risk associated with this proven technology and the relatively low capital cost to retrofit existing facilities makes commercialization likely. In addition, MCR technology is easily adaptable to cyclone, T-fired, or wall-fired boilers and thus has wide-spread applicability.

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LIST OF ABBREVIATIONS AND UNITS

A or amps	Ampere
ABB C-E	Asea Brown Boveri Combustion Engineering
ABS	Absolute
AC	Alternating Current
acfm	Actual Cubic Feed Per Minute
A/F	Air-to-Fuel Ratio (Pounds Air Per Pounds Coal)
am	Ante Meridiem
An	Area of Sampling Nozzle, ft^2
ASTM	American Society for Testing and Materials
Avg	Average
$BaCl_2$	Barium chloride
BL	Baseline
BSF	Boiler Simulator Furnace
Btu	British Thermal Unit
B&W	Babcock and Wilcox
C	Carbon, Elemental
EC	Degrees Celsius
C-factor	Pitot Tube Calibration Factor
CCOFA	Close-Coupled Over Fire Air
CCT	Clean Coal Technologies
CEM	Continuous Emission Monitoring
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CONSOL R&D	CONSOL Energy, Research & Development Department
COV	Coefficient of Variation
DC	Direct Current
Delta H	Dry Test Meter Orifice Calibration
Det	As Determined
DOE	U.S. Department of Energy
DSC	Distributed Control System
dscf	Dry Standard Cubic Feet
dscfm	Dry Standard Cubic Feet per Minute
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESEERCO	Empire State Electric Energy Research Corporation
ESP	Electrostatic Precipitator
EF	Degrees Fahrenheit
F-Factor	Fuel Factor Relating Flue Gas Volume to Coal Composition
FGD	Flue Gas Desulfurization
FGR	Flue Gas Recirculation
fpm	Feet per Minute
fps	Feet per Second

ft or ‘	Feet
ft^2	Square Feet
ft^3	Cubic Feet

LIST OF ABBREVIATIONS AND UNITS (cont.)

gm	Gram
gr	Grain
gr/dscf	Grains per Dry Standard Cubic Foot
H	Hydrogen, Elemental
H_2O	Water
H_2O_2	Hydrogen Peroxide
h or hr	Hour
Hg	Mercury
in. or “	Inches
in. H_2O	Inches Water Column
“ Hg	Inches Mercury
HGI	Hardgrove Grindability Index
kacfm	Actual Cubic Feet per Minute x 1000
kpph	Kilo (Thousand) Pounds Per Hour
kV	Kilovolt
kW	Kilowatts
lb	Pound
lb/hr	Pound(s) per Hour
lb/lb-Mole	Pound(s) per Pound-Mole
lb/MM Btu	Pound(s) per Million British Thermal Units of Heat Input
LNCFS	Low-NOx Concentric Firing System
LNCFS-3	LNCFS Level 3 (Equipped with SOFA and CCOFA)
LOI	Loss on Ignition
mA	Milliamperes
MACS	Miniature Acid Condensation System
MCR	Micronized Coal Reburning
min	Minute
mm	Millimeters
MM	Million
MM Btu	Million British Thermal Units
MW	Megawatt
MWe	Electrical Generation Station Power Rating, Megawatts-Electric
ND	Not Determined
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NOx	Nitrogen Oxides, NO and NO_2
N_2	Nitrogen Gas
NYSEG	New York State Electric & Gas Corporation

NYSERDA	New York State Energy Research and Development Authority
O	Oxygen, Elemental
OFA	Overfire Air
O_2	Oxygen Gas
O&M	Operating & Maintenance
% ISO	Percent Isokinetic Sampling Data
P	Pressure

LIST OF ABBREVIATIONS AND UNITS (cont.)

PC	Pulverized Coal
PM	Particulate Matter
pm	Post Meridiem
ppm	Parts per Million
ppmv	Parts per Million by Volume
PRSD	Percent Relative Standard Deviation
psig	Pounds per Square Inch, Gauge
QA/QC	Quality Assurance/Quality Control
ER	Degrees Rankine
RACT	Reasonably Attainable Control Technology
reb	Reburn
rms	Root Mean Square
rpm	Revolutions per Minute
S	Sulfur, Elemental
“S” Pitot	Stausscheibe or Reverse Type Pitot Tube
SCA	Specific Collection Area, i.e. ft^2 of ESP Plate Area per ft^3 of Flue Gas
scfm	Standard Cubic Feet per Minute at 60EF and 1 Atm.
SDEV	Standard Deviation
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SOFA	Separated Over Fire Air
SoRI	Southern Research Institute
SOx	Combined Sulfur Dioxide and Sulfur Trioxide
STD	Standard
Std Dev	Standard Deviation
Std ft^3	Cubic Foot at Standard Conditions
TC	Thermocouple
Temp	Temperature
TFN	Total Fixed Nitrogen
T-fired	Tangentially-fired
tph	Tons per Hour
TPO	Technical Project Officer
TR	Transformer-Rectifier
TVA	Tennessee Valley Authority

µm	Micrometers
V	Volt
V-I Curve	Voltage-Current Relationship, Especially in Reference to ESP
Vel	Velocity
Vol	Volume
W	Watt
wt	Weight
Y-Factor	Dry Test Meter Volume Calibration

1.0 INTRODUCTION

1.1 PURPOSE OF THE PROJECT PERFORMANCE AND ECONOMICS REPORT

The purpose of this Project Performance and Economic Report is to consolidate, for the purpose of public use a technical account of the total work performed for the Micronized Coal Reburning Demonstration for NOx Control, Cooperative Agreement DE-FC22-93PC92642. Design and cost information for the project are included in lieu of the issuance of a separate Public Design Report.

This report contains the background and history of the project. Also included is a description of the technology employed and how it was applied in two different facilities (the New York State Electric & Gas Corporation Milliken Station in Lansing, NY and the Eastman Kodak, Kodak Park, Boiler #15 in Rochester, NY). Descriptions of tests conducted at both locales are provided. Comprehensive descriptions of the results are summarized in the body of the report and detailed in several appendices. The participants' conclusions are provided, as well as plans for commercialization.

The intent of this report is to inform and assist the energy sector in judging the potential of micronized coal reburning technology for commercialization. In addition, this report should be useful to federal, state, and local authorities in making sound policy and regulatory decisions regarding the deployment of the micronized coal burning technology.

1.2 OVERVIEW OF THE PROJECT

1.2.1 Background and History of Project

1.2.1.1 Background

In response to The Department of Energy Program Opportunity Notice (PON), Solicitation Number DE-PS01-91FE62271, for Clean Coal Technology IV, Tennessee Valley Authority (TVA) joined with Fuller-MicroFuel Division, Energy and Environmental Research Corporation, and Fluor Daniel to propose a full scale demonstration of Micronized Coal Reburning Technology to control nitrogen oxide (NOx) emissions on a wall-fired steam generator at the Shawnee Fossil Plant near Paducah, Kentucky. Due to operational and environmental strategy changes, TVA's Shawnee Fossil Plant was unable to demonstrate the technology.

New York State Electric & Gas Corporation (NYSEG) and Eastman Kodak Company (Kodak) offered to fulfill and expand the research and demonstration objectives established by the TVA for Micronized Coal Reburning, recover the demonstration schedule and expand DOE's repayment opportunities.

This was accomplished by taking advantage of the project team already in place for the Milliken Clean Coal Demonstration for project management, teaming with Kodak for the MicroMill™ Demonstration and leveraging DOE's previous investment at Milliken to demonstrate Micronized Coal Reburning while making only minor modifications to existing equipment.

The reconfigured project involved applying Micronized Coal Reburning on an existing 150-MWe, tangentially fired unit equipped with low NOx burners and overfired air without installing a separate reburn system. An existing DB Riley MPS mill with a dynamic classifier was used to micronize the coal. At Eastman Kodak's Kodak Park Site Power Plant a cyclone boiler was retrofitted to demonstrate the MicroMill™ and micronized coal reburning technology.

The program was carried out under Cooperative Agreement DE-FC22-93PC92642 Amendment #A005. Selection was effected in March 1996. The cooperative agreement was signed August 1997. The program was 34 months in duration. The program was cost shared; 28.8% DOE, 71.2% participants. Total agreement value was $8,683,499.

1.2.1.2 **Technology**

MCR technology reduces NOx emissions with minimal furnace modifications, and the improved burning characteristics of micronized coal enhance boiler performance. The micronized coal reburning project utilized coal that was very finely pulverized (about 80% less than 325 mesh). This micronized coal, which may comprise up to 30% of the total fuel fired in the furnace, is fired high in the furnace to create a fuel-rich reburn zone at a stoichiometry of 0.8-1.0. Downstream of the reburn zone, overfire air is injected into the burnout zone at high velocity to achieve good mixing to ensure complete combustion. Overall excess air is 15%.

In addition to NOx reduction, several additional problems are solved concurrently by the availability of the reburn micronized fuel, as an additional fuel to the furnace:

- The mill capacity added to produce the micronized coal allows units that are mill limited to reach their maximum continuous rating; and this becomes a very economical source of additional generation capacity.

- The reburn burners can serve as low load burners, and units can achieve a turndown of 8:1 on nights and weekends without consuming expensive auxiliary fuel.

- The existing pulverizers can be adjusted to operate on a variety of coals with improved performance, since they do not need to provide the entire fuel supply.

- Better carbon burnout at lower excess air and improved efficiency can be obtained by the combination of micronized coal reburn fuel and better pulverizer performance.

MCR technology can be applied to cyclone-fired, wall-fired and tangentially-fired pulverized coal units. The overfire air system can also be easily adapted to incorporate in-furnace sorbent injection for SO_2 control with minimal capital expenditures.

MCR technology for NOx control operates in the same manner as natural gas reburning on coal-fired boilers. The entire furnace operates as a low-NOx system with the existing burners being operated in a slightly oxidizing mode. The technology requires accurate fuel/air control. A reburn zone is established above the top row of existing burners. The micronized coal is fired into a substoichiometric reburn zone, consumes oxygen very rapidly and with a residence time of 0.5 to 0.6 seconds, converts NOx to molecular nitrogen. Above the reburn zone, high velocity overfire air uniformly mixes with the substoichiometric furnace gas to complete combustion, giving a total excess air of 15%. Optimally, MCR technology reduces NOx emissions by 50 to 60%.

Much work had already been performed to develop this technology prior to this project. There are two parts to the technology: coal micronization and reburning. Reburning for NOx control has been practiced, mainly using natural gas or oil as the reburn fuel. Although successful, use of these fuels for this purpose suffers from one or more of the following disadvantages: reliability of supply, especially in winter; higher fuel costs; problems in firing dual fuels; and reduced boiler efficiency because the higher hydrogen content results in an increase in moisture in the flue gas. Burning of micronized coal has been demonstrated, and these operations have shown the advantage of burning ultrafine coal.

The MicroMill™ pulverizer used to produce the micronized coal at the Kodak site had been thoroughly tested, both in pilot-scale and in commercial-scale operations.

Combustion in a furnace employing reburning technology can be divided into three zones.

- Primary Zone - This is the main heat release zone, where 70 to 80% of the total heat input to the system is released under slightly oxidizing conditions.

- Reburning Zone - This is the zone where the reburning fuel (normally 10 to 30% of the total fuel) is injected downstream of the primary zone to create a fuel-rich NOx reduction zone. Reactive nitrogen species react with hydrocarbon fragments from the reburning fuel to produce intermediate species, such as ammonia (NH_3), hydrogen cyanide (HCN), and nitrogen (N_2).

- Burnout Zone - In this zone, air is added to produce overall fuel-lean conditions and oxidize all remaining fuel. All of the nitrogen species will either be oxidized to NOx or reduced to N_2.

MCR is an outgrowth of other types of reburning which use natural gas and conventional pulverized coal, but MCR results in improved boiler efficiency and performance. Micronized coal pulverizers have already been demonstrated as ignition burners on coal-fired utility boilers at the same capacity as used for this reburn demonstration. DOE is presently sponsoring gas reburning on wall-, cyclone-, and tangentially-fired boilers and conventional pulverized coal reburning on a cyclone-fired boiler.

There has been only one coal reburn fuel staging project for NOx control conducted in the United States prior to this program. There are, however, a substantial number of natural gas reburning projects in the U.S. coal-fired power plants. Pilot projects also have been conducted using coal as a reburn fuel, and a full-scale CCT-II demonstration project was operated at the Nelson Dewey Station of Wisconsin Power & Light Company. That project used pulverized coal as reburn fuel on a cyclone-fired boiler.

The development of micronized coal technology has been advanced primarily in the United States, where the standard for micronized coal is 80% less than 43 µm (325 mesh). Most of the operating history of micronized coal-fired combustion systems is on industrial-sized process furnaces.

Development of the centrifugal-pneumatic mill, used to produce micronized coal, began in the fall of 1983; and, during an 18-month development period, several prototype mills were designed, built, and tested. MicroFuel Corporation (MFC) is the developer of this technology. The ownership of the technology is now Fuller Power Corporation.

In 1984, there developed significant interest in micronized coal firing as a replacement for gas or oil firing for industrial applications, including aggregate dryers, cement plants, packaged boilers, and other process furnaces. Since a 5 ton/hr mill was required to meet the firing rates of most furnace applications, a 30-inch mill was developed with a classifier, based upon a horizontal cyclone design and a solid steel cast impeller.

Several 30-inch mill systems were built in the mid-to-late 1980s, most of which were installed on aggregate dryers. However, by 1988 the focus was on utility applications, and a more reliable impeller was required. Therefore, a replaceable-blade impeller was designed. This unit was thoroughly tested at full scale at MicroFuel's R&D facility and at Duke Power's Cliffside Power Station.

The MicroFuel Corporation installed micronizing mills in 1988 at Duke Power's Cliffside Station on a 600 MWe Combustion Engineering tangentially-fired furnace. The main oil guns were removed from corners 2 and 4, and micronized coal-fired burners were installed for start-up ignition. This project used the same type of system as used at Cliffside, except that it was designed to be run continuously.

1.2.1.3 **Pilot Scale Testing**

Pilot scale combustion studies were performed to evaluate the effectiveness of using bituminous coal fired by Kodak as a reburning fuel. The primary objectives of these tests were to assess the impacts of fuel-specific parameters on the effectiveness of the Kodak coal (Table 1.2.1.4-2) as a reburning fuel, and to characterize the impacts of reburning process parameters on the NOx reductions achievable with coal reburning at the typical operating conditions of Boiler No. 15. This testing was necessary since it is not possible to predict the NOx control performance achievable with a specific coal based upon simple coal properties and coal analyses. These tests were conducted at EER's Test Site in El Toro, California, which is equipped with a number of facilities developed for evaluation and scale up of the reburning process.

The tests were conducted using EER's Boiler Simulator Furnace (BSF) which is shown in Figure 1.2.1.3-1. The BSF consists of a down-fired refractory lined combustion tunnel followed by a horizontal convective-pass simulator. The combustion tunnel is designed to simulate the time-temperature characteristics of the flue gases in a typical utility boiler furnace. Cooling panels and rods can be inserted through ports in the walls of the furnace in order to adjust the thermal profile to simulate a specific furnace. The ports provide access for the insertion of injectors for the reburning fuel and overfire air.

The main burner was fired on natural gas or coal. For natural gas firing, ammonia was premixed with the combustion air to provide a controlled initial NOx level. The reburning fuel was Pittsburgh seam bituminous coal provided by Kodak. The reburning coal was injected into the furnace through an injector designed to provide rapid dispersion of the coal into the flue gas from the main burner. Air or nitrogen was used to transport the coal to simulate recycled flue gas. The range of conditions investigated in the study represented the range of conditions expected for the Kodak boiler. The main burner was fired at ten percent excess air. The reburning fuel was injected at rates between 10 to 35 percent of the total furnace heat input, and at a temperature of 2,600°F. The reburning zone residence time was varied from 400 to 600 milliseconds. The initial NOx level was varied between 700 to 1,000 ppm (dry, corrected to 0% O_2).

The impacts of various process parameters on the effectiveness of the bituminous coal fired by Kodak in the reburning process are shown in Figures 1.2.1.3-2 to 4. The influence of reburning zone stoichiometry and reburning transport medium on the performance of coal reburning is shown in Figure 1.2.1.3-2. Here, the data are reported as the fraction of heat input with the reburning fuel. For conditions with ten percent excess air in the primary zone, a reburning zone stoichiometric ratio of 0.9 corresponds to a reburn fuel usage of approximately 18 percent, when nitrogen is used as the transport. The use of air as a transport requires a higher percentage of reburn fuel usage to reach the same reburn zone stoichiometry in comparison to the use of an inert transport. When inert gas is the transport medium, the data show that increasing the quantity of reburning fuel used improves NOx control up to about 25 percent reburn fuel addition. Increasing the reburning fuel above this level does not result in an increase in performance. When air is the transport medium, a slight increase in performance is achieved when the reburn fuel heat input is increased above 25 percent. However, previous studies have shown that the performance improvement decreases when the amount of reburn fuel is increased above 30 percent.

Kinetic studies of reburning chemistry have shown that an optimum in reburn zone stoichiometry, or reburn fuel usage, exists due to the generation of peak concentrations of CH radicals at a stoichiometric ratio near 0.9. Increasing the amount of reburning fuel added to the reburning zone does not result in an increase in radical concentrations above these peak levels. Hence, no further benefit of increased reburn fuel usage is observed. For fuels containing bound-nitrogen species, such as coal, increasing the quantity of reburn fuel above the optimum level can have a negative impact on reburn performance, since the additional fuel nitrogen added to the reburn zone does not have an opportunity to be processed under favorable conditions.

The reburning zone residence time is a key consideration for application of coal reburning to Kodak Boiler No. 15. The size of the furnace and available access to locate reburn fuel and overfire air injectors limit the residence time which can be achieved in the furnace. Based upon the injection elevations identified for the Kodak boiler, a nominal bulk residence time of nearly 500 milliseconds is expected. The impact of reburning zone residence time on coal reburning is shown in Figure 1.2.1.3-3. Increasing the reburning zone residence time from 400 to 600 milliseconds did not have a significant impact on the NOx control performance with the bituminous coal. However, based on the experience of others, reductions in the furnace residence time are expected to have a negative impact of reburn performance.

The impact of the initial NOx level entering the reburning zone is shown in Figure 1.2.1.3-4. This figure shows the NOx reductions achieved as a function of the primary NOx level for coal reburning with both air and inert transport media. In general, the performance of coal reburning appears to decrease as the initial NOx level is decreased below 600 ppm. At NOx emissions levels, typical of the Kodak boiler operation (i.e., 700 to 900 ppm), the effects of primary NOx level on reburning effectiveness are expected to be minor.

The results of these experiments indicated that the bituminous coal fired by Kodak could be used as an effective reburning fuel at the conditions typical of Boiler No. 15. Comparison of the results of this study with EER's database on reburning fuels, indicates that the trends obtained with the bituminous coal fired by Kodak are similar to those which might be expected for a fuel with similar characteristics. Comparison of the performance of the bituminous coal fired by Kodak to other lignitic, subbituminous, and bituminous coals, and to natural gas, tested on the pilot-scale facility at similar conditions, as shown in Figure 1.2.1.3-5, indicates that the bituminous coal fired by Kodak is only a moderate reburning performer. This comparison suggests that the use of reburning coals more reactive than the current coal could result in further reductions in NOx emissions. At initial NOx levels and bulk residence times representative of the Kodak furnace, NOx reductions of approximately 60 percent were achievable when using simulated FGR as a transport fuel, while 50 percent control was achievable using air as a transport. Achieving these levels of control at full scale were dependent upon the extent to which effective mixing of the reburning fuel was achieved, and the extent to which the furnace flow field characteristics impacted the reburning zone residence time.

1.2.1.4 **Design Basis**

The pilot-scale tests discussed in the preceding section confirmed the overall viability of using the bituminous coal fired by Kodak as a reburning fuel. The data indicate that high levels of NOx reduction could be achieved provided that adequate residence time is available in the reburning zone. The recommended approach for applying coal reburning to the Kodak boiler involved injection of the reburning fuel at an elevation in the furnace just above the exit height of the cyclones, and injection of overfire air at a distance downstream of the reburning fuel injection elevation selected to provide sufficient residence time in the furnace for the reburning zone, while providing adequate time for overfire air mixing prior to entrance of the flue gas into the generating bank. The proposed reburning fuel and overfire air injection elevations are shown in Figure 1.2.1.4-1. The bulk residence time between the reburning fuel and overfire air injection elevations is estimated to be approximately 500 milliseconds. However, the general flow field in the boiler is extremely complex, and the effective residence time in the reburning zone is estimated to be less than half of this value.

In applying the coal reburning process to the Kodak boiler, the design of the reburning fuel and overfire air injectors must provide rapid mixing of the reburning fuel and overfire air in order to maximize emissions control and to minimize carbon monoxide emissions and unburned carbon. In full-scale applications of reburning technology to date, means of enhancing the mixing and distribution of the reburning fuel are required. This requirement is driven by the need to rapidly mix the relatively small quantity of reburning fuel with a much larger quantity of flue gas over the large cross section typical of most boiler furnaces. The use of recycled flue gas or FGR has been the preferred means of improving reburning fuel mixing. FGR can have a negative impact on boiler performance, depending on a number of factors such as the extent to which the heat absorption profile is modified by reburning and the quantity of FGR used to control the reburning fuel mixing. Using coal as a reburning fuel, a means of transporting the coal to the boiler is also needed. This transport can be FGR or air. However, as shown by the results of the pilot-scale tests, the use of air as a transport medium may have a negative impact on NOx reduction performance, and requires the use of additional reburning fuel to reach optimum reburning zone stoichiometries.

Since only front wall injection of the overfire air is feasible on the Kodak boiler, the overfire air system was designed to provide good jet penetration as well as good lateral dispersion across the boiler depth and width. These goals were accomplished using a relatively small quantity of overfire air, and in the face of a relatively high cross stream velocity. In addition, the overfire air system was designed to provide some flexibility to respond to changing boiler conditions. EER's approach to the design of an effective overfire air system used a double-concentric nozzle which produces two air streams which can be controlled for good mixing and operational flexibility. The design developed for the Kodak boiler was used successfully in EER's second generation gas reburning system installed at Public Service of Colorado's Cherokee Station.

Kodak's Boiler #15 typically operates at steam generation rates between 300,000 to 400,000 lb/hr. The boiler peak steam generation rate is 440,000 lb/hr. At steam loads below 300,000 lb/hr, slag freezing can occur. In addition, it would be desirable to operate the reburning system over as wide a range of boiler operation as possible. The relationship between boiler load and coal flow to the cyclones is illustrated in Figure 1.2.1.4-2 for various assumed levels of reburn fuel heat input. As indicated in this figure, the minimum coal flow to the cyclones, corresponding to a steam generation rate of 300,000 lb/hr, is approximately 26,000 lb/hr. At this load, no reburning fuel could be injected since it would require operation of the cyclones below the minimum coal flow rate necessary to maintain acceptable slag tapping. Boiler load can be increased from this level by adding fuel through the reburning system. At a steam generation rate of 335,000 lb/hr, it would be possible to operate the coal reburn system to provide approximately ten percent of the total boiler heat input. As load is increased above this level, the level of coal reburning could be increased to higher levels, and hence, higher levels of NOx control could be achieved. At the nominal boiler full load of 400,000 lb/hr, approximately twenty percent of the total boiler heat input could be supplied by the reburning system. Up to thirty percent of the boiler heat input could be supplied by the reburning system at the boiler maximum continuous rating.

Assuming that the minimum allowable coal flow to the cyclones is approximately 26,000 pound per hour, it is possible to construct a curve of maximum reburn fuel vs. boiler load. The resulting curve is shown in Figure 1.2.1.4-3. This figure also shows the reburn load which can be achieved using a single Fuller micromill with a capacity of 8,000 pounds per hour. At boiler loads up to approximately 375,000 pounds per hour of steam, the reburn load which can be achieved with a single micromill is equivalent to the maximum load which can be used without encountering slag tapping problems. At boiler loads above 375,000 pounds per hour, the maximum level of reburn load which can be achieved with one mill in operation is between 20 to 22 percent. Fuller guaranteed the performance of the mill to 8,000 pounds per hour. Given that the guaranteed capacity of the mill will limit the reburn system operation to substantially less than the maximum level of reburning which could be utilized at loads above 375,000 pounds per hour, it was recommended that the reburn system be designed to provide coal from both of the mills to the reburning fuel nozzles. Operation with two mills in service will ensure that Kodak has sufficient flexibility to achieve the highest levels of NOx control possible by maximizing the reburn fuel load, and should provide sufficient margin in the system design should operation of the cyclones at lower than normal excess air levels not be possible. However, a critical aspect of this design is the approach for accommodating operation with only one mill in service, for times when one mill is being repaired.

Although adequate mixing of the reburning fuel could be achieved with either air or recycled flue gas as the transport medium, the limited levels of reburning fuel which can be added to the boiler over the boiler load range, and the need for relatively high levels of control imply that only FGR should be considered for use as an injection and transport medium. Fuller indicated that the use of FGR should not have an impact on mill operating performance provided that the mill outlet temperature can be controlled. Therefore, it was recommended that this option be used at Kodak Boiler #15. The results of the process design studies discussed in the following section indicate that effective reburning fuel mixing can be achieved at FGR levels between five to ten percent. In the process design studies, it was assumed that clean flue gas will be taken from the outlet of the electrostatic precipitator, and that a water quench system will be used to cool the flue gas to control the mill outlet temperature.

The design basis for the coal reburning system is shown in Table 1.2.1.4-1. The fuel analysis used in the system design is shown in Table 1.2.1.4-2. The reburning system design was based on the maximum steam generation rate of 440,000 pounds per hour. Based upon the specifications shown in Table 1.2.1.4-1, the process flow sheet and material balance for reburning with coal at the maximum load shown in Figure 1.2.1.4-4 and Table 1.2.1.4-3 were developed. The operating stoichiometries selected in the process design basis reflect values which are expected to maximize the NOx reduction achieved with the reburning system while minimizing the impacts of reburning on overall boiler performance. For the primary zone, the cyclone burners will be operated at an excess air level of approximately thirteen percent. The excess air is consistent with the requirements for normal cyclone operation, but is lower than that typical of the current boiler operation. At the maximum steam flow, the reburning zone will be operated at a stoichiometry of approximately 0.8, which is based upon operation at the maximum reburn coal flow for this load. Operation with this coal flow is consistent with the desire to maximize the NOx reductions achievable with the reburning system. Finally, the burnout zone will be operated at the boiler normal excess air level of fifteen percent.

Figures 1.2.1.4-5 and 1.2.1.4-6 show proposed curves of cyclone coal flow, reburn fuel flow, and overfire air flow as a function of the boiler steam generation rate. In Figure 1.2.1.4-5, the amount of coal used in the reburning system corresponds to the maximum allowable value which can be added through the reburning system while still maintaining acceptable slag tapping conditions. As shown in Figure 1.2.1.4-5, boiler load can be controlled by increasing the reburning fuel flow rate for boiler loads between 330,000 to 440,000 pounds per hour. At boiler loads below this level, the reburning system would be taken out of operation, except for cooling air added through the reburn fuel and overfire air ports.

To develop injector specifications which would result in effective mixing of the reburning fuel and overfire air, an isothermal flow model of Boiler #15 was constructed. The model is approximately 1:8 scale and provides a detailed simulation of the furnace from the burners through the first horizontal tube bank of the superheater. The wingwalls and lower furnace screen tubes were also simulated in the model. The model was constructed of acrylic to provide a high level of visual access. Following construction of the model, it was connected to one of the test stands in EER's Aerodynamics Modeling Facility, located in Irvine, California.

Flow visualization studies were performed to define the characteristics of the bulk model flow field. Flow visualization was conducted using neutrally buoyant bubble tracers. These tracers were used to identify general furnace flow patterns and flow streamlines. Bubbles were injected through the cyclone burners and followed the burner flows as it developed through the furnace thereby revealing bulk flow features of the furnace flow field such as recirculation, swirl, and turbulence intensity. A general sketch of the model flow field is illustrated in Figure 1.2.1.4-7. As shown in this figure, the flow passing through the screen tubes in the lower furnace turns upward and flows into the upper furnace. Due to the rapid expansion of the furnace above the cyclones, a large recirculation zone develops in the front portion of the furnace. The flow exiting the lower furnace is highly biased towards the rear wall of the furnace. The nose located on the rear wall constricts the furnace area, and defines the location of the point of closure of the recirculation zone which forms above the cyclone. This results in the generation of an upper furnace velocity distribution at the nose plane which is biased towards the generating bank. The furnace flow then negotiates the turn into the generating bank in the upper furnace.

The bulk flow field characteristics were further quantified by velocity measurements at two cross sections within the model furnace. The two planes selected for analysis consisted of the reburning fuel and overfire air injection elevations. The results of the velocity measurements are shown in Figure 1.2.1.4-8, which shows the upward component of the velocity measurement normalized to the mean reference value. In general, the flow field is complex, and highly three dimensional. The velocity measurements performed at the reburn fuel injection elevation confirm the general features shown in the flow field sketch which were high velocities near the rear wall, and a recirculation zone near the screen tubes. High velocities were also measured along the rear wall at the overfire air elevation.

The large recirculation zone which forms in the furnace is expected to have a negative impact on reburn performance. First, since the recirculation zone forces the main upward flow to occupy a substantially smaller area than the furnace cross section, the residence time of the bulk gases in the reburning zone is substantially reduced. Second, flow visualization of the overfire air jets indicate that there is a tendency of overfire air to be entrained into the recirculation zone, and to be recirculated to the lower furnace. Entrainment of overfire air into the reburning zone will increase the effective stoichiometry. Both of these factors indicate that the reburning fuel injection system should be designed to provide extremely rapid mixing of the reburning fuel. This requirement points to the need for using multiple small-diameter, high-velocity injectors for the reburning fuel injection system.

Following characterization of the model flow field, preliminary designs for the reburning fuel and overfire air were screened using smoke tracers. Smoke was added to the simulated reburning fuel and overfire air jets to evaluate the jet penetration characteristics. The results of these studies indicated that reburning fuel jet velocities in the range of 250 to 300 feet per second are necessary to ensure that the reburning fuel jets achieve sufficient penetration into the flow field. In addition, overfire air jet velocities between 450 to 500 feet per second are needed to ensure that the overfire air jets penetrate into the high velocity flow near the rear wall of the boiler.

Once the ideal jet penetration characteristics had been established, the mixing performance of various reburn fuel and overfire air injection systems were quantitatively analyzed using dispersion measurement techniques. In this technique, tracer dispersion measurements were taken in a cross-sectional plane in the furnace model downstream of the injection elevation to quantify the mixing performance of a specific injection system. The dispersion measurement provides an indication of the local concentration of a tracer gas which is input through the injection system. The tracer gas, which is typically methane, is uniformly mixed in the air prior to injection through the jets into the model. The concentration level at selected points within the measurement plane can be related to the desired reburning zone stoichiometry by analytical means. The well-mixed concentration level is measured in the exhaust duct of the isothermal model where complete mixing is guaranteed. The point dispersion data are compared to the well-mixed condition and are normalized to the design stoichiometry of the particular furnace region. An ideal injection system will achieve uniform dispersion which will result in a uniform stoichiometry at the measurement plane.

The results of dispersion measurements conducted for the proposed reburning fuel and overfire air injection systems are shown, respectively, in Figures 1.2.1.4-9 and 1.2.1.4-10. Figure 1.2.1.4-9 shows contours of the measured distribution of stoichiometry at a plane located in the reburning zone which corresponds to a residence time of approximately 200 milliseconds. In this figure, uniform mixing of the reburning fuel corresponds to a stoichiometry of 0.9. As indicated by the fact that a significant portion of the dispersion profile is near the target stoichiometry, the distribution of reburning fuel provided by this configuration is relatively uniform. This result is reflected in the coefficient of variation (COV) for this case, which is 0.34. A COV of zero implies uniform reburning fuel distribution. A COV of less than 0.4 is considered adequate for achieving good performance with a reburning system. Figure 1.2.1.4-10 shows contours of constant stoichiometry measured at the midpoint of the nose. In this figure, uniform mixing of the overfire air corresponds to a stoichiometry of 1.15. The results of this profile indicate that relatively good mixing of the overfire air can be achieved along the rear wall using the coaxial overfire air jet design, but that coverage in the area along the front wall is light. Preliminary measurements in the flow model indicate that the use of swirl in the outer passage can improve coverage in this region.

Based upon these studies, the design specifications for the reburning system are summarized in Table 1.2.1.4-4. The reburning fuel nozzles will utilize a single jet design where the coal transport line diameter is reduced at the nozzle to increase the velocity of the transport FGR and coal. This design minimizes the need for a boost stream. A high pressure FGR fan will be used to supply the transport flue gas stream. The reburning fuel nozzles should be located equally spaced along the rear wall of the furnace. To turndown the reburning fuel system, it is expected that the coal flow from the mill will be reduced, and that the total FGR flow rate to the nozzles will be maintained constant. This approach will permit effective mixing of the reburning fuel to be maintained at reduced reburn fuel flow rates.

The overfire ports are designed to utilize a coaxial jet design. The inner passage is designed to achieve good penetration of the core overfire air stream over the reburning system's required operating range. The outer passage is designed to mix overfire air into the flue gas along the rear wall, and used to provide the majority of the overfire air system turndown capability. Figure 1.2.1.4-11 shows the layout of the overfire air nozzles. After testing at Kodak, B&W showed better results could be achieved with only outer flow and no swirl.

1.2.2 **Project Organization**

The Project Organization is shown in Figure 1.2.2-1. The Prime Contractor to the U.S. DOE is the New York State Electric & Gas Corporation (NYSEG). Project participants who demonstrated technology, provided resources and agreed to Program Opportunity Notice (PON) requirements included Fuller Power Corporation, Energy and Environmental Research Corp., DB Riley, Inc., Eastman Kodak Company, CONSOL Inc., B&W, and ABB. Organizations that assisted in the dissemination of technical information included the Empire State Electric Energy Research Corporation (ESEERCO), Electric Power Research Institute (EPRI), and the New York State Energy Research and Development Authority (NYSERDA). As participants, these organizations had access to data and technical information. They were able to provide information to their members through standard technical transfer channels. This technical transfer was coordinated by NYSEG's R&D Department.

1.2.3 **Project Description**

The project demonstrated the effectiveness of reducing nitrogen oxide (NOx) emissions with an advanced micronized coal reburning technology. This technology can be applied with existing combustors as well as with new injectors. The same coal used in the main combustion zone was used as the reburning fuel. This entails no incremental fuel cost or chemical cost compared to other NOx reduction technologies. In addition to achieving lower NOx emissions, the micronized coal firing system can also provide improved operating performance such as greater turndown without support fuel. This reburn technology can also be combined with various sulfur dioxide (SO_2) control technologies such as fuel switching, dry sorbent injection, or other post-combustion technologies.

The advantages of this technology over other commercially available NOx control technologies are:

! Economical Fuel

Reburning is recognized to be an effective technology for controlling NOx emissions in pulverized coal-fired boilers. Most demonstrations to date have been with natural gas or oil as the reburn fuel. Although both fuels have demonstrated effectiveness, they are subject to one or more of the following disadvantages:

- Availability, especially in the winter
- Unpredictable fuel cost
- Operational problems firing dual fuel
- Boiler efficiency penalty

! Increased Mill Capacity

Higher fineness can be obtained since the existing mills will have reduced duty. This will help maintain the unburned carbon level in fly ash and improve the air entrainment characteristics for using it as a concrete additive.

! No Additional Chemical/Catalyst Cost

The post combustion NOx reduction technologies can offer the same or higher levels of NOx reduction. However, the reagent and catalyst costs will increase the plant O&M costs substantially. Coal reburning will incur minimal incremental O&M costs.

! No Ammonia Slip

SNCR or SCR tend to produce ammonia slip if the process is not controlled carefully. Ammonia slip has been known to cause air heater pluggage, increased fan power requirements, fly ash contamination, and CEM equipment malfunction. Coal reburning does not utilize any reagent. Therefore it will avoid such operational problems.

The term reburning refers to a process where a fraction of the fuel is injected into a zone downstream of the main combustion zone to form a reducing atmosphere. Additional air is added further downstream to complete the combustion.

The reburning process consists of three main zones: the primary or main combustion zone, the reburning zone, and the burn-out zone. Figure 1.2.3-1 shows a schematic of the reburning process as it applies to a utility boiler.

1. Primary Zone

This main heat release in this zone accounts for approximately 75% to 80% of the total heat input to the system. Operating under 1.0 to 1.1 stoichiometric ratio conditions, the primary zone produces the initial NOx species, primarily NO.

2. Reburning Zone

Reburning fuel is injected downstream of the primary zone to create a fuel-rich zone. Three major general reactions take place in the reburning zone which affect the reburning process:

a. NO reacts with hydrocarbon radicals in reactions such as:

NO + CH ° N + CHO
NO + CH ° HCN + O

which increases the nitrogen radical pool.

b. Inter-conversion of nitrogen species among different fixed nitrogen compounds (NO, HCN, or NH_3) occurs. Elemental nitrogen (N) will likely be formed at this stage.

c. The formation of molecular nitrogen by the reaction of nitrogen radicals with NO. The reaction

$$NO + N \rightarrow N_2 + O$$

sometimes referred to as the reverse Zeldovich reaction mechanism, is the most probable path, although reactions with NH_2 species are possible.

Consequently the nitrogen oxide formed in the primary zone will be converted to N_2, NH_3, HCN, or retained as NO. When the reburning fuel contains nitrogen (such as coal or oil), fuel nitrogen could remain with the char or form NO, HCN, and NH_3. Thus, the products of this zone contain nitrogen species which can be converted to NO. The sum of these gas-phase species is referred to as total fixed nitrogen (TFN).

3. Burnout Zone

In the burnout zone, air is added to produce overall fuel-lean conditions which oxidize all the unburned fuel. The TFN or char nitrogen is converted to NO or to N_2.

Typically the primary zone is operated at stoichiometries between 1.0 and 1.1 to minimize NOx production while reducing potential waterwall corrosion and carbon burnout problems. The reburn zone would normally be operated at stoichiometries between 0.8 and 0.9. The burnout zone would then be operated to achieve minimum NOx production while avoiding operational problems. A typical furnace outlet stoichiometry is 1.2.

Two sites hosted the MCR demonstration; NYSEG's Milliken Station Unit #1 and Eastman Kodak's Boiler #15.

1. Milliken Station (Micronized Coal Reburn Demonstration with MPS Mill and Dynamic Classifier)

NYSEG's Milliken Station has two (2) 150 MWe units each with a CE designed tangential coal-firing single furnace boiler. The 1958 Unit 1 was recently retrofitted with an ABB C-E Low NOx Concentric Firing System (LNCFS), four (4) new Riley Stoker MPS 150 pulverizers with dynamic classifiers, an upgraded Belco precipitator, two (2) ABB Air Preheater Q-Pipe air heaters, an upgraded Westinghouse WDPF control system and a S-H-U Flue Gas Desulfurization (FGD) system. Some preliminary emissions data show that Milliken Unit #1 has reduced its NOx emissions from a 0.58 lb/hr MM Btu baseline level to 0.40 lb/MM Btu or lower. The SO_2 emissions also were reduced by as much as 98%. This unit is currently required to comply with NYSEG's system NOx tonnage cap under the Title I OTCD limit. Starting January 1, 1996, it also was required to meet the Title IV - Acid Deposition Control NOx emission limits of 0.45 lb/MM Btu on an annual basis.

The LNCFS system was installed in 1994 to achieve the NOx emission requirements. It includes four (4) elevations of coal burners, three (3) elevations of oil guns, auxiliary air and CFS air compartments around the coal burners, two (2) close-coupled overfire air (CCOFA) compartments, and three (3) separated overfire air (SOFA) compartments. NOx emissions are controlled with the CCOFA and SOFA dampers and are monitored with a stack CEM system.

The MCR process was demonstrated on Milliken Unit #1 using the existing equipment installed under the DOE CCT IV Demonstration project. The existing Riley MPS 150 mills with dynamic classifiers operated with fineness approaching 75% through 325 mesh. The operation of the mills was tested at high classifier speed to demonstrate the required 80% through 325 mesh or higher fineness. The upper burner compartment was used to inject the reburn for this demonstration.

By using the existing milling equipment to demonstrate the coal reburning technology at Milliken Station, no impacts on the boiler performance and LOI level were expected due to the system flexibility and the short distance between the reburn zone and the OFA location. A simplified diagram of the Milliken fuel system is provided in Figure 1.2.3-2.

2. Kodak (Primary Site for MicroMill™ and Micronized Coal Reburn Project)

Kodak's #15 Boiler is a Babcock Wilcox Model RB-230 cyclone boiler commissioned in 1956. It is located in Building 31 within the Kodak Park Site in Rochester, New York. The unit was designed to generate 400,000 lbs/hr of 1400 PSIG, 900 F steam with a rated heat input of 478 MM Btu/hr at Maximum Continuous Rating (MCR). The fuel supplied to this boiler is Pittsburgh seam medium to high sulfur coal with a Hardgrove Grindability Index (HGI) of approximately 55 and a higher heating value of 13,300 Btu/lb.

As part of this project, Kodak installed a Fuller MicroMill™ coal micronizing system, reburn injectors/burners and over-fired air downstream of the main cyclone burners. The MicroMill™ is unique in that it uses a tornado like column of air to create a rotational impact zone where the coal particles actually strike against each other and thus crush themselves. The typical particles generated by the MicroMill™ are approximately 20 µm whereas normal pulverized coal is about 60 microns. This increases the surface area by ninefold allowing for improved combustion in a shorter time period. This was critical to the success of the project since the boiler is small and has a low residence time. The project used >90% <325 mesh micronized coal for reburn fuel. New micronized coal and gas reburn injectors/burners and overfire air ports were installed. The existing air and gas handling systems were modified to reroute the air/gas to the new burners and ports. New instrumentation and controls were required to operate, control, and alarm the boiler. The existing control panel and logic were replaced with a distributed control system installed in a new control room. A process block diagram showing the reburn system is provided in Figure 1.2.3-3. The other core technology that was employed in this project was the use of NOx reburn technology. NOx reburn has been used principally with natural gas or oil as the fuel. Reburning of pulverized coal has been demonstrated and proven to be advantageous to the alternative fuels.

Kodak presently has an existing disposal program for its coal combustion by-products. The ash produced during the MCR program at Kodak had higher fly ash carbon content than ash produced prior to the program. This has affected the disposal of the ash waste stream. See Section 4.

1.2.4 **Site Description**

Micronized coal reburn was demonstrated at two sites (NYSEG's Milliken Station in Lansing, NY and at Eastman Kodak's Boiler #15 Kodak Park, Rochester, NY). At Milliken, a MPS 150 mill with dynamic classifier micronized coal for use as a reburn fuel in a 150 MWe tangentially fired unit. At Kodak, a Fuller MicroMill™ micronized coal for use as a reburn fuel in a 60 MWe cyclone fired unit.

1.2.4.1 **Milliken Station**

Site Description

The MPS mill and "T" fired MCR demonstration project was conducted at NYSEG's Milliken Station located on the east shore of Cayuga Lake, approximately 12 miles northwest of Lansing, New York. The plant site is at latitude 42E36'30"N and longitude 76E38'15"W. The UTM coordinates are 4,178,380m N and 365,470m E. The site is in the Town of Lansing in Tompkins County near the junction of Seneca, Cayuga, and Tompkins counties. The total property area consists of 322 acres (Figure 1.2.4.1-1). Figure 1.2.4.1-2 shows the location of the site relative to major cities in central New York State. The surrounding region is a sparsely populated agricultural area. The bulk of the area's population and industry is concentrated in the cities of Syracuse, Binghamton, Elmira, Auburn, and Ithaca.

Cayuga Lake is approximately 39 miles long in a NNW-to-SSE direction, with east-to-west width varying between 1 and 3 miles and a maximum depth of 435 feet. At the site, the lake width is approximately 1.75 miles, with a normal elevation of approximately 382 feet (msl). In the site region, the terrain rises from the lake shore to an elevation of about 800 feet (msl) within 1 mile. Within 3 miles east of the station site, the terrain rises to about 1100 feet (msl). From this region out to 50 miles or more, the terrain generally ranges above 1000 feet (msl) with widely scattered high points between 2000 and 3000 feet (msl).

The terrain west of Cayuga Lake is generally similar to that east of the site. Other glaciated valleys similar to that of Cayuga Lake exist west and northeast of the site, forming the other Finger Lakes.

The general climate in the central New York Finger Lakes region is dominated by polar continental air masses tracking from the north and west. Frequent invasions of air masses from the Gulf of Mexico result in rapid variations of weather conditions. The regional climate is characterized by long cold winters and cool summers with occasional warm, humid periods. Precipitation is evenly distributed throughout the year.

Seismic activity in the region of the site is low. Previous research showed that earthquakes in the northeastern United States are infrequent. The earthquakes that do occur in the northeastern United States are usually of shallow focus and characterized by low magnitude and/or intensity.

This site is accessible. It has adequate water, rail transport, roadways, electric power, labor force, coal supply and other utilities that made it a suitable demonstration site.

Site Suitability

There are two coal-fired units, Units 1&2, at Milliken Station. They are Combustion Engineering pulverized coal-fired units which are rated at nominal 150 MW each and operate under balanced draft mode. Each unit is tangentially fired with four elevations of burners at each of the four corners. Unit 1 was completed in 1955 and Unit 2 was completed in 1958. During the period 1992 to 1994, a forced oxidation, formic acid enhanced wet flue gas desulfurization (FGD) system, using the Saarberg-Holter-Umwelttechnik (S-H-U) process, was added to both units as a Clean Coal IV demonstration. Other improvements to Milliken's units included conversion to a distributed control system, installation of DB Riley MPS mills with dynamic classifier and ABB/CE LNCFS-3 burners with overfire air; replacement of the electrostatic precipitators with Belco wide spaced plate units; demonstration of a CE/ABB heatpipe airheater on Unit 2 and modifications to the draft systems.

Milliken Units 1 and 2 have, over the years, proven to be two of the most efficient and reliable units in the nation. Units 1 and 2 are base loaded units, this assured a good demonstration and provided the opportunity for observation of the technologies in commercial operation.

Milliken Station Units 1 and 2 are two comparably sized boilers. This feature was key to the development of this project. It allowed demonstration of the spit module absorber concept and, at the same time, permitted independent operation of the S-H-U process on each boiler unit. Operation of identical absorbers at independently variable conditions allowed process data to be more fully verified and facilitated identification and analysis of abnormalities, either process or physical, as they occurred.

The location of the site in the Finger Lakes region of New York State makes this plant a contributor to acid rain deposition in the Adirondack and the Catskill Mountains. A consequence of this project on the proposed site was to provide environmental benefits to these important natural resources. Due to Milliken's location in New York State, transboundary emissions to Canada could theoretically be reduced.

NYSEG is committed to an active community contact program and made public contacts to inform officials and concerned citizens about plans and address their questions.

1.2.4.2 **Kodak**

Site Description

The MicroMill™ and cyclone-fired MCR demonstration project was conducted at the Eastman Kodak Company's Kodak Park Site in urban Rochester, New York approximately 1 mile west of the Genesee River and within Kodak Park, specifically Building No. 31. The plant site is at latitude 43E12'00"N and longitude 77E38'00"W. The UTM coordinates are 4,178,380m N and 365,470m E. The total property area consists of 1300 acres. Figure 1.2.4.1-1 shows the location of the site relative to other major cities in central New York State. The surrounding region is a densely populated urban area with several industrial sites, shopping centers and retail stores. The bulk of the area's population and industry is concentrated within a five (5) miles radius of the demonstration site.

The Kodak Park Site has two power plants. The East Power Plant, in B-31, contains five coal-fired boilers and four oil-fired package boilers and one front fired oil boiler. The West Power plant contains four coal fired boilers. At the proposed site, B-31, there are four coal-fired Babcock and Wilcox stoker boilers which have been in service approximately 55 years. The package boilers are approximately 25 years old and are used as a back-up steam supply source. The cyclone boiler was manufactured by Babcock and Wilcox and is 30 years old.

The #15 Boiler, a Babcock and Wilcox cyclone boiler was installed in 1956, and was selected for modification to add a micronized coal reburn system. This modification is in accordance with an agreement between Kodak and the New York State Department of Environmental Conservation (DEC). This project should provide Kodak the opportunity to more economically meet the emissions reduction targets set forth for NOx RACT as identified in that agreement and also allow Kodak to operate this boiler up to its full MCR rating.

The general climate in the central New York Finger Lakes region is dominated by polar continental air masses tracking from the north and west. Frequent invasions of air masses from the Gulf of Mexico result in rapid variations of weather conditions. The regional climate is characterized by long cold winters and cool summers with occasional warm, humid periods. Precipitation is evenly distributed throughout the year.

Seismic activity in the region of the site is low. Previous research showed that earthquakes in the northeastern United States are infrequent. The earthquakes that do occur in the northeastern United States are usually of shallow focus and characterized by low magnitude and/or intensity.

<u>Site Suitability</u>

The demonstration site is an operating power plant with all the facilities that were necessary to demonstrate this technology, such as access to water, rail transport, roadways, electric power, labor force, coal supply and other utilities as may be required.

- Water Supply - Eastman Kodak required no additional water requirements for this boiler modification.
- Railroad Access - Railroad access was already available on-site to meet the requirements for coal deliveries to the station.
- Roads - State Route 104 (commonly known as Ridge Road within Rochester) can be accessed from the NY State Thruway (1-90), via Interstate Routes 390 and 490.
- Electric Power - All power required for both the construction and operational phases of the project were easily met from Kodak Park's own generation facilities.
- Labor Force - Construction labor forces were available through the Rochester Building and Construction Trades Council which has as members craftsmen from all required trades, including carpenters, iron workers, laborers, plumbers and electricians. The operating force was supplied either from current Kodak employees at the power plant or from the labor force of the surrounding area.
- Coal Supply - Eastern U.S. coal is projected as the major source of fuel supply. Kodak Park can accommodate coal delivery via rail or truck. The majority of coal is currently delivered by rail.

! Other Utilities - All other utilities such as potable water and wastewater treatment were provided by the existing power plant resources.

The site for this project has been within the confines of Kodak Park for nearly 80 years. Because the work was accomplished totally within the plant's power house, there was no cause for local concerns about the site's appropriateness for a technology demonstration. NYSEG and Kodak believed the surrounding communities as a whole would be supportive of the project due to its environmental benefits. Eastman Kodak is committed to an active community contact program and made public contacts to inform officials and concerned citizens about the project and addressed their questions.

1.2.5 **Project Schedule**

The project phases were the following:

1.1 Phase 1 - Engineering

- 1.1.1 Milliken Station Engineering and Design
- 1.1.2 Kodak Plant Engineering and Design
- 1.1.3 Phase 1 Project Management

1.2 Phase 2 - Construction

- 1.2.1 Milliken Station Construction
- 1.2.2 Kodak Plant construction
- 1.2.3 Phase 2 Project Management

1.3 Phase 3 - Operation and Demonstration

- 1.3.1 Milliken Station Operation Demonstration
- 1.3.2 Kodak Plant Operation and Demonstration
- 1.3.3 Phase 3 Project Management

The duration and dates of each phase of the project were:

Task I - Milliken

Phase I (6 months)	10-15-95 to 4-15-96 Engineering
Phase II (1 month)	4-15-96 to 5-15-96 Construction
Phase III (19 months)	5-15-96 to 12-31-97 Operation & Demonstration

Task II - Kodak

Phase I (6 months)	10-15-95 to 4-15-96 Engineering
Phase II (8 months)	4-15-96 to 1-15-97 Construction

Phase III (12 months)   1-15-97 to 12-31-97 Operation & Demonstration

A detailed milestone chart is provided as Figure 1.2.5-1.

1.3 **OBJECTIVE OF THE PROJECT**

1.3.1 **Summary**

The program had a number of goals. These goals were to:

- Establish the operating performance and limits of a plant operating with MCR.

- Demonstrate the long term reliability of the systems and materials utilized in micronized coal reburning.

- Make a direct comparison of the Fuller MicroMill™ and the D. B. Riley MPS150 (with dynamic classifier) micronizing systems using the same fuel.

- Provide confirming data from a full scale furnace that the coal reburn system can achieve its objective of significant NOx reduction.

    - Demonstrate micronized coal reburning technology on a cyclone boiler with at least a 50% NOx reduction.

    - Demonstrate micronized coal reburning technology in conjunction with low NOx burners on a tangential fired boiler with a 25-35% NOx reduction.

- Document boiler performance over a sufficiently long period of time to identify long-term trends in emissions and boiler behavior when micronized coal is used in a reburn application.

Specifically, micronized coal reburn impacts on the following were assessed.

- NO, NOx, NO_2, O_2, CO, CO_2 and SO_2 emissions
- Particulate emissions
- Emissions during various load conditions
- Unburned carbon in the fly ash
- Pulverizer/mill performance
- Coal flow rate and size distribution
- Air preheater performance
- Boiler slagging and fouling
- Waterwall and convection pass corrosion
- Furnace temperature profile
- Boiler thermal efficiency
- Combustion system reliability

! Boiler load response

1.3.2 **Discussion**

The objectives of the project were unchanged throughout the project duration.

1.4 **SIGNIFICANCE OF THE PROJECT**

Reburning for NOx control has been practiced, mainly using natural gas or oil as the reburn fuel. Although successful, use of these fuels for this purpose suffers from one or more of the following disadvantages: reliability of supply, especially in winter; higher fuel costs; problems in firing dual fuels; and reduced efficiency because the higher hydrogen content results in an increase in moisture in the flue gas. This project demonstrated the burning of micronized coal as a reburn fuel. These operations have shown the advantage of burning ultrafine coal over natural gas or oil as the reburn fuel. The demonstration project tested all aspects of the Micronized Coal Reburning (MCR) technology at commercial scale on commercial coal-fired units. Data collection, analysis, and reporting were performed during the operations phase and included on-stream factors, material balances, equipment performance, comparisons with previous results, efficiencies, and NOx emission levels. The data generated on a mill used to micronize coal (Fuller MicroMill™) and on firing micronized coal for electric power production and NOx reduction will be directly applicable to other commercial applications and will provide valuable information to permit scaleup to larger units. The MicroMill™, which was used to produce the micronized coal, has been thoroughly tested, both in pilot-scale and in commercial-scale operations. Thus, all components of the technology were previously demonstrated, although not in the configuration demonstrated in this project.

Until this project, there were no other operations demonstrating the exact combination of the technologies demonstrated.

The novel portions of the system are the advanced micronized coal reburning system and the Fuller MicroMill™. All of the other equipment is standard equipment and is commercially available. Therefore, the level of risk associated with the operation of all equipment other than the MicroMill and reburn system was initially low.

The successful demonstration on the Milliken 150 MWe Unit #1 and the Kodak 60 MWe Boiler #15 units typical of a large portion of the nation's utility operating base shows that there is the potential for wide application of the technology. Although demonstrated on a cyclone-fired unit (at Kodak) and a tangentially-fired unit at Milliken, the technology should be equally applicable to wall-fired units.

Although primarily developed as a means for decreasing NOx emissions from coal-fired furnaces, the MCR technology has several other potential benefits which will make it attractive for many operators of coal-fired units. Among the possible benefits are:

! Increased boiler capacity on mill-limited units.

- Providing back-up for existing pulverizers, while having no negative impact on furnace performance.

- Improved efficiency due to lower excess air and decreased loss on ignition.

- Competitive capital, operating, and maintenance costs.

- Ease of retrofit, since the reburn burners and overfire air ports are the only furnace wall penetrations required. MicroMill™ systems are compact and lightweight and can typically be mounted on the operating floor adjacent to bunker outlets, and existing burners and registers can be modified at minimal expense for fuel/air staging.

- Ability to fire low-sulfur, low-cost subbituminous coals as a reburn fuel.

- Up to 30% reduction in existing pulverizer throughput, thus permitting classifiers to be adjusted for a significant improvement in coal fineness.

- Improved steam and superheat temperature at low load, as a result of firing micronized coal in the upper furnace and rapid devolatilization and char burnout of the reburn fuel.

The combination of micronized coal and reburning for NOx control is a natural fit for existing older fossil units. Together, they provide flexibility and economies of scale that are unattainable with other NOx control technologies. With MCR providing NOx reductions of 50 to 60%, most tangential- and wall-fired furnaces should be able to meet the Clean Air Act Amendments NOx compliance limits without expensive back-end control methods.

For MCR, the primary competing NOx control technology is low-NOx burners. Although low-NOx burners will meet the current emission requirements, the benefits of MCR technology will allow it to compete effectively with low-NOx burners. These benefits include the use of the micronized coal system for start-up and low-load operation, and restoring mill-limited units to rated capacity. Installing MCR technology will reduce the load on existing mill systems, improve carbon burnout, reduce excess air, and increase unit efficiency. The technology is expected to be competitive from a capital and operating standpoint with low-NOx burner applications.

Despite slow growth of electric power demand and a corresponding decrease in generating plant construction during the 1980s, demand for electricity is expected to continue to increase at a rate that will not only require new generating capacity but will put additional demands on the existing coal-fired generating base. Recently, the Electric Power Research Institute (EPRI) compiled a listing of 75 MW to 300 MW coal-fired units that were built in the U.S. between 1945 and 1965. This list totals 389 units with nearly 60 GW of capacity. Although they will reach their 40-year life spans between 1985 and 2005, these units are candidates for retrofitting and continued operation, either as baseload or peaking units. As new generating capacity is added, this will further relegate the older installed base to cyclic duty. Benefits of the MCR technology will best be realized on this boiler population. The technology will not only meet the NOx emission requirements but will allow the operation of these units on low load while firing only coal, thereby reducing operating costs and ultimately the cost of electricity delivered to the end user.

Because this project successfully demonstrated, at commercial scale, a novel technology for meeting the expected NOx limits on existing coal-fired units and because the technology can use virtually any coal and can be easily retrofitted to many types of coal-fired furnaces it is believed that the success of the demonstration project reduced the risk and provided a great impetus to commercialization.

1.5 **DOE'S ROLE IN THE PROJECT**

1.5.1 **DOE's Role**

The DOE was responsible for monitoring all aspects of the project and for granting or denying approvals required by the cooperative agreement. The DOE Contracting Officer is DOE's authorized representative for all matters related to the cooperative agreement.

The DOE Contracting Officer appointed a technical project officer (TPO) who was the authorized representative for all technical matters and had the authority to issue "Technical Advice" which might have:

- Suggested redirection of the cooperative agreement effort, recommended a shifting of work emphasis between work areas or tasks, or suggested pursuit of certain lines of inquiry which assisted in accomplishing the Statement of Work.

- Approved all technical reports, plans, and items of technical information required to be delivered by the Participant to the DOE under the Cooperative Agreement.

The DOE TPO did not have the authority to issue technical advice which:

- Constituted an assignment of additional work outside the Statement of Work.

- In any manner caused an increase or decrease in the total estimated cost or the time required for performance of the Cooperative Agreement.

- Change any of the terms, conditions, or specifications of the Cooperative Agreement.

- Interfered with the Participant's right to perform the terms and conditions of the Cooperative Agreement.

All technical advice was issued in writing by the DOE TPO.

The DOE provided periodic reviews of the technical and management aspects of the project and organized meetings, workshops, and conferences to report progress of this project and exchange technical information at the conclusion of each phase and milestones identified by the Cooperative Agreement. The DOE formally reviewed the program status and authorized continuation of funding of the project.

1.5.2 **<u>Management Plan</u>**

The project team assembled for the Milliken Clean Coal IV Technology Demonstration Project managed and controlled the technological and administrative aspects of this project. This greatly reduced the management costs associated with the micronized coal demonstration and leveraged DOE's existing investment at Milliken.

1.5.2.1 **Management Approach**

The Micronized Coal Technology Demonstration project conducted at the NYSEG site (Milliken) was managed by NYSEG's Milliken Clean Coal IV Demonstration Project Team (FGD Team), with extensive support and cooperation from the Generation Technical Services Department of the Electric Business Unit (Figure 1.5.2.1-1) The FGD Team consisted of an accomplished group of individuals actively fulfilling the requirements of the DOE sponsored Milliken Clean Coal IV Demonstration Project.

A fully dedicated project management core team was supplemented using corporate resources such as legal, accounting, purchasing, training, quality assurance, contact administration, research and development, and public information. Technical support was provided from the existing matrix organization.

Kodak and NYSEG established a partnership that enabled NYSEG the opportunity to support and advise Kodak project members on the duties and responsibilities related to DOE protocol. Founded upon the recent experience gained from the Milliken Clean Coal IV Demonstration Project, NYSEG's FGD Team provided Kodak with direction and support for fulfilling DOE requirements in the proposal.

For the Kodak demonstration Babcock & Wilcox, an architect/engineering firm, was utilized to supplement administrative, engineering and construction management efforts. NYSEG & Kodak routinely perform major projects in this manner and organizational procedures to effectively plan, organize, and control the work were in place for the MCR program.

Mr. Jeffrey Smith, Vice President - Electric Generation is the executive sponsor of the Micronized Coal Demonstration Options at the Milliken Site. Mr. Smith provided the DOE Project Manager a direct line of communication to NYSEG's executive management. When Mr. Smith was not available, Mr. James W. Rettberg was available to provide a prompt, effective response to the DOE Project Manager.

Mr. Ronald C. Morrison, Vice President and General Manager was the executive of the Micronized Coal Demonstration project at Kodak. Mr. Morrison provided the Project Manager a direct line of communication to Kodak's Executive Management. When Mr. Morrison was not available, Mr. Peter Loberg was available to provide a prompt, effective response to the Project Manager.

1.5.2.2 **Project Team and Key Individuals**

Over the project duration several key project team members changed. An organization chart depicting the project team members, and key individuals at the conclusion of the project, is shown in Figure 1.5.2.1-1. Note that the dedicated Project Management Team consisted of the project manager, cost and schedule, clerical, and one additional position to be matched with the project phase.

The DOE-assigned Project Manager directly interfaced with Mr. Dennis O'Dea, the NYSEG Project Manager. Mr. James Harvilla replaced Mr. O'Dea near the end of the program.

The Project Manager was the single point contact between the DOE and this demonstration project and was responsible for fulfilling Cooperative Agreement commitments. This included the responsibility to coordinate the activities of support and team members to ensure successful completion of project objectives. Each participating team member had assigned a key person(s) responsible for the internal administration functional performance and workmanship of individuals within the respective team member's organization. Team member progress was monitored by the Project Manager through monthly technical and financial reports and periodic reviews of audits.

2.0 **TECHNOLOGY DESCRIPTION**

The Micronized Coal Demonstration Project is part of Round 4 of the U.S. DOE's Clean Coal Demonstration Program. Originally planned for demonstration at TVA's Shawnee Plant, the demonstration was transferred to Eastman Kodak Company (Kodak) and New York State Electric & Gas Corporation (NYSEG). The project includes the demonstration of micronized coal reburn technology for the reduction of NOx emissions from a 150 MW class tangentially-fired boiler at NYSEG's Milliken Station (Task I) and a cyclone boiler at Kodak (Task II). The cyclone boiler application includes the utilization of a retrofit Fuller MicroMill™ to provide micronized reburn coal. Milliken utilized an existing DB Riley MPS mill with dynamic classifier to provide the reburn fuel. The following discussion provides a separate description of the technology as implemented for each task.

2.1 **DESCRIPTION OF THE DEMONSTRATED TECHNOLOGY**

Reburning is a combustion modification technology which removes NOx from combustion products by using fuel as a reducing agent. The fundamental principle of reburning - that fuel fragments can react with NO to form molecular nitrogen - was first demonstrated as a viable NOx control technique over twenty years ago. This control technique is particularly effective at controlling NOx emissions, and can be easily retrofitted to utility boilers. To implement the process on a large utility boiler, fuel is injected above the main combustion zone to provide a slightly fuel rich environment or "reburning zone." In this zone nitrogen oxides formed in the primary combustion zone are reduced to molecular nitrogen. Following the reburning zone, additional combustion air is added to the boiler to oxidize carbon monoxide and any remaining fuel fragments exiting the reburning zone.

2.1.1 **Primary Advantages**

The primary advantages of reburning over other available NOx control technologies are that:

! Reburning provides high levels of NOx control.

! Reburning can be implemented without significant impact on boiler performance. Although reburning implementation can impact the distribution of heat absorption in the boiler, these effects are generally small in comparison to variations due to normal changes in boiler operation (e.g., fouling).

! Reburning produces no measurable by-product emissions. Unlike other additive NOx control processes such as urea or ammonia injection, reburning does not result in the release of other pollutants such as ammonia or nitrous oxide.

! Reburning is fuel flexible and can be applied to gas-, oil-, or coal-fired boilers. These fuels also can be used as the reburning fuel in the process itself.

! Reburning can be applied to all types of fossil fuel fired boilers.

Reburning on a utility boiler requires dividing the combustion air and fuel into multiple (usually three) zones which stage the fuel and air addition to the furnace. Figure 2.1.1-1 shows an illustration of the typical approach for applying reburning to a utility boiler.

Primary Combustion Zone: The heat release in this zone normally accounts for 80 to 85 percent of the total heat input to the combustion system. The main fuel is burned under fuel-lean conditions resulting in high levels of NOx emissions. The major component of NOx is NO.

Reburning Zone: The reburning fuel, which accounts for the other 15 to 20 percent of the fuel heat input, is injected downstream of the primary zone in sufficient quantity to form a slightly fuel rich zone where NOx from the primary zone is reduced. In the reburning zone, hydrocarbon radicals, such as CH, generated during breakdown of the reburning fuel react with NO molecules from the primary zone to form other nitrogenous species such as hydrogen cyanide, HCN. The HCN then decays through several reaction intermediates, $NCO \rightarrow NH \rightarrow N$, and ultimately forms N_2 via the reverse Zeldovich reaction:

$$NO + N \rightarrow N_2 + O$$

Burnout Zone: In the third and final zone, additional combustion air is added to oxidize carbon monoxide and any remaining fuel fragments, and to produce overall fuel-lean conditions. The remaining reduced nitrogen species are generally oxidized to NO, or reduced to N_2, depending upon specific conditions at the point of overfire air introduction.

2.1.2 **Critical Variables**

The results of small-scale studies have shown that the most critical parameters which impact reburning performance are: primary NOx level; reburning zone stoichiometry; reburning zone temperature and residence time; and mixing of the reburning fuel and the overfire air with the bulk furnace gases. The importance of zone stoichiometries, residence times and temperatures, and mixing is discussed below.

Operating Stoichiometries The most important stoichiometry in the process is that of the reburning zone. The impact of this parameter on NOx emissions achievable with various reburning fuels is shown in Figure 2.1.2-1. Here, the reburning zone stoichiometric ratio is defined as the ratio of the total air supplied to the primary and reburning zones to the total stoichiometric air requirements of the primary and reburning fuels. As shown in this figure, overall NOx reductions are highest when the reburning zone stoichiometry is in the vicinity of 0.90. To minimize the amount of reburning fuel needed to reach the optimum stoichiometry, the primary combustion zone should be operated as close to stoichiometric as possible. For coal-fired boilers, operation of the primary combustion zone with an excess air level of ten percent or less is preferred to bring the reburning fuel requirements to between 18 and 20 percent of the fuel heat input to the furnace, and to maintain the nominal coal flame combustion characteristics. Lower stoichiometries in the primary combustion zone can be used provided that combustion stability and carbon burnout are not sacrificed. In the burnout zone, overfire air is added to bring the overall furnace combustion system to its normal (no reburn) operating stoichiometry. When applying reburning, it is desirable to minimize the overall excess air level in order to improve the thermal efficiency of the unit. This reduction can be accomplished if the reburning system is designed to provide effective mixing of the overfire air, and if acceptable to the boiler thermal cycle operation.

Furnace Temperatures The furnace gas temperature at which the reburning fuel is injected has an impact on the process efficiency, with higher temperatures preferred. Typically, this requirement suggests that the reburning fuel should be injected as close to the primary zone as possible. However, the reburning fuel must be injected at a distance above the primary zone sufficient to allow burnout of the volatile hydrocarbons in the primary flame and reduction of the oxygen concentration entering the reburning zone. The temperature at which the burnout air is injected does not directly influence the efficiency of the reburning process for most gaseous and liquid reburning fuels, but it is important that the temperature is high enough to allow oxidation of carbon monoxide and hydrocarbon fragments from the reburning zone to occur readily.

Zone Residence Times Sufficient residence time must be available in the primary combustion zone to allow combustion of the primary fuel to proceed near completion. However, the residence time of the reburning zone is the most critical to the process. Sufficient residence time in the reburning zone should be available to allow mixing and reaction of the reburning fuel with the residual oxygen and the products from the primary combustion zone. For most combustion systems, small-scale studies have shown that the reburning zone residence time should be between 300 to 500 milliseconds. Finally, sufficient residence time must be provided in the burnout zone to permit oxidation of the carbon monoxide and hydrocarbon fragments from the reburning zone.

Mixing Pilot-scale studies of the reburning process have also shown the importance of effective mixing in both the reburning and burnout zones. Effective mixing of the reburning fuel optimizes the process efficiency by making the most efficient use of the available furnace residence time, while effective mixing of the overfire air reduces carbon monoxide emissions and unburned carbon or soot. For most combustion systems, good mixing is important to minimize operational impacts while maximizing NOx reductions. In order to ensure that the reburning fuel is mixed effectively in the furnace, the use of recycled flue gas to boost the nozzle velocity has been employed in full-scale demonstrations. Although recent results indicate that the use of flue gas is not necessary for natural gas reburning provided that the reburning fuel nozzle is designed to provide good mixing of the reburning fuel, the use of coal as a reburning fuel requires the use of a transport medium for the coal. Pilot-scale coal reburning tests conducted by EER indicate that the oxygen content of the carrier gas can impact the emissions control performance achievable with coal reburning, in addition to requiring the use of more reburning fuel to achieve a target reburning zone stoichiometry.

2.1.3 **Fuel Preparation**

2.1.3.1 **Task I - Milliken**

NYSEG's Milliken Station has two 150 MW units with CE designed tangential coal-firing single furnace boilers. Both units have been retrofitted with ABB Low NOx Concentric Firing Systems (LNCFS-3™)[1] and four new DB Riley MPS 150 pulverizers with dynamic classifiers.

Each pulverizer supplies one elevation of corner burners. To simulate and test a reburn application, the lower three coal elevations were biased to carry approximately 85% of the fuel required for full load. The top burner provided the remaining fuel. The speed of the dynamic classifier serving the top mill was increased to provide a micronized fuel. An incremental NOx reduction was achieved in addition to the reduction already obtained with the LNCFS-3[1].

As a comparison to the NOx reductions demonstrated with the reburn simulation, the burners were arranged to more deeply stage combustion. This simulated the ABB TFS2000R™ combustion system.[2] Whereas the LNCFS-3 utilizes close coupled and separated over-fire air injection zones, the new system has an additional zone of separated over-fire air. The result is a burner that is capable of deeper staging.

2.1.3.2 **Task II - Kodak**

Coal Micronizer

Preparation of the reburning fuel for the Kodak cyclone-fired boiler reburn system was performed using a MicroMill system supplied by Fuller Mineral Process Inc. The MicroMill™ is a patented centrifugal-

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[1] LNCFS-3 is a trademark of ABB Combustion Engineering, Inc.

[2] TFS 2000R is a trademark of ABB Combustion Engineering, Inc.

pneumatic mill that works on the principle of particle-to-particle attrition. Coal is conveyed with a hot air stream into the cone area, creating a vortex of air and coal particles. As the diameter of the cone section of the mill becomes larger, the air to coal velocity ratio decreases. The coal assumes a position in the cone based on each particle's size and weight. Particles of similar size will form bands of material with the larger particles at the bottom of the cone. Smaller particles will move through these bands and enter the vortex creased by the rotating blades in the rotational impact zone of the mill. As these smaller particles collide with the larger particles, size reduction occurs. When a particle's size is small enough to attain the required velocity, it passes through the blades located in the scroll section of the mill and exits the mill to a static classifier.

A static classifier is used for final particle size distribution. Oversized material falls through a rotary air lock and back into the feed airstream of the mill. Stripping the gas provided to the classifier can be adjusted to fine tune the classifier collection efficiency allowing larger or smaller particles to pass to the boiler.

The MicroMill system fits in approximately a thirteen foot by nine foot area and is only about twelve feet high. The mill's overall size and weight made it an ideal choice for Kodak's tight space limitations and its modular construction makes it easy to perform maintenance. The mill is designed with wear resistant materials in areas contacting the feed being processed to minimize maintenance. When maintenance is required, the cone can be unbolted, lowered on the pivot pin and rotated for access to the rotor, wear liners and replaceable blades.

The MicroMill is supported by Fuller's extensive research and development facilities which includes a full scale MF3018 MicroMill for product testing and demonstration. The Kodak feed materials were tested on this unit to determine expected capacity, fineness and power consumption. In the lab a capacity of three tons per hour at 86% <44μm was obtained. The limiting factor in the laboratory was motor horsepower. The motor for the project was increased from 150 HP to 200 HP; thus high capacities were achieved in the field. Power consumption expected for the mill is about 37.3 kW/ton of material processed. In addition, the fineness required for the application is 80% <44μm, which will further increase the capacity of the system. Flexibility has been designed into the system to provide a higher fineness product or greater capacity at a lower fineness.

The two-mill system for the Kodak projected included:

Mill and motor
Classifier
Recycle and feed rotary airlock
Blow through tee and feed piping
Classifier and mill air control valves
The gas flow meter

The mill is equipped with a water-cooled bearing jacket, vibration sensor, bearing RTD's and a proximity switch. The bearing jacket will allow the use of Kodak's uncooled flue gas as a transport medium. By utilizing the water cooled jacket the need for expensive flue gas cooling equipment was eliminated.

Coal Transportation and Injection

A MCR system schematic is shown in Figure 2.1.3-1. The slipstream for flue gas is extracted from the boiler just downstream of the precipitator and is boosted by a single fan to feed both coal micronizers. FGR is used to transport coal to the boiler and also boost its injection momentum to ensure that the reburn fuel is mixed effectively in the furnace.

Two coal micronizers with classifiers are used in the system. Each micronizer is supplied coal from a bunker through a screw feeder. The FGR system assists in the micronizing process and in operation of the classifiers. The mills are capable of operating singly or as a pair. Only one was used in the test program.

The micronized coal exiting the mill is merged into a single 18-inch pipe for transportation to the boiler. The line is then divided into eight 6-inch segments by a coal flow splitter supplied by EER. The splitter is designed to apportion the coal into equal segments without incurring any pressure drop. Upstream of the splitter is a coal rope breaker (RopeMaster©) supplied by Rolls-Royce/International Combustion, which enhances the splitter's effectiveness. Downstream of the splitter are eight FlowMastEER© dampers designed by EER that are used to perform final adjustments to the coal flow balance. The dampers can also be used to create flow biasing.

Eight micronized coal injectors are installed, six on the rear wall and one on each side wall near the rear wall. The injectors utilize the considerable momentum provided by the FGR transport gas plus additional design features to enhance coal penetration. Each injector is equipped with a variable swirl device to control the mixing characteristics of each fuel jet as it enters the furnace. Adjustments were made during initial startup to optimize the injector effectiveness. The coal injectors were designed by EER specifically for this project.

Overfire Air System

Located on the front wall are four overfire air injectors. These injectors utilize a dual-concentric overfire air design. The injectors are designed to provide good jet penetration as well as good lateral dispersion across the depth and width. Each injector is equipped with an integral damper to maintain the desired injection velocity as load changes and a swirler which, when adjusted, provides for optimum mixing in the burnout zone.

Controls

Kodak installed a new Coen burner management system and replaced the complete boiler control system with a Westinghouse WDPF distributed digital control system. The new controls operate both the existing equipment and the micronized coal reburning system, with all normal start/stop/modulate operator actions occurring in the control room. Critical operations are interlocked to prevent inadvertent operation of equipment when such operation may present an operating hazard or other undesirable condition. The controls are designed to shut down the reburning system while maintaining operation of the boiler.

2.2 **DESCRIPTION OF THE DEMONSTRATION FACILITIES**

2.2.1 Task I - Milliken

As part of the Milliken Clean Coal Technology Demonstration Project Unit 1 was retrofitted with new Low NOx Concentric Firing System (LNCFS-3) with both close coupled and separated overfire air ports to achieve up to 40% of the NOx reduction. Table 2.2-1 describes Unit 1 after the retrofit. The burners developed by ABB C-E utilize both air staging and early devolatilization of the coal to control the combustion NOx formation. The close coupled and separated overfire air systems have a total of five elevations of overfire air ports to allow for operational flexibility. The combined overfire air capabilities approached 40% of the total combustion air. The coal nozzles were initially designed to retain flame front by creating recirculation zones at the burner tip. These coal nozzles were later redesigned for higher sulfur coal applications by increasing the burner outlet velocity and allowing for more air cooling around the fuel compartment. A set of offset air nozzles are part of the windbox design to deliver "cushion air" between the fireball and the waterwalls in order to minimize the fireside corrosion due to a reducing environment.

Although the new equipment offers a great degree of operational flexibility, the new burner systems are more sensitive to coal quality variation than the original equipment. Higher volatility coals (>36%) can cause close ignition and coking on the burner tips. The increased sensitivity can be explained by the air staging effect which reduces the secondary air velocity to maintain the flame front distance. The operators have developed awareness of such impact and are able to respond to the coal change before problems occur.

Since Milliken Unit 1 can produce coal fineness approaching the "micronized" level, a coal reburn was simulated on the existing LNCFS-3 burners by biasing mill loading and air dampers. This simulated reburn condition was used to determine if NOx reductions can be realized for future use during ozone season and whether a full conversion to micronized coal reburn system would be cost effective.

2.2.2 Task II - Kodak

A detailed description of the Eastman Kodak demonstration facilities as retrofitted for the MCR project is provided in Appendix A "Kodak Project Design Basis." A simplified Process Block Diagram is shown in Figure 1.2.3-3.

2.3 **PROPRIETARY INFORMATION**

No information related to the micronized coal reburning project either in construction, demonstration, or data analyses for either Task I (NYSEG's Milliken Station) or Task II (Eastman Kodak's Boiler #15) is considered proprietary.

2.4 **PROCESS FLOW DIAGRAM**

2.4.1 Task I - Milliken

The Process Flow Diagram for the coal and combustion air process flow is provided in Figure 2.4-1. A description of the equipment is provided in Table 2.2-1.

2.4.2 Task II - Kodak

The Process Flow Diagram for the coal and combustion air process flows is provided in Figure 2.4-2.

2.5 **STREAM DATA**

2.5.1 Task I - Milliken

Post retrofit process parameter data for the long-term test (see Appendix 5.0-4) are provided in Table 2.5-1.

2.5.2 Task II - Kodak

A simplified table of the process flow rates, temperatures, and pressures for all process streams depicted in Figure 2.4-2 is provided in Table 2.5-2. Process streams in Table 2.5-2 are identified by the same stream numbers as used in Figure 2.4-2.

2.6 **PROCESS AND INSTRUMENTATION DIAGRAMS**

2.6.1 Task I - Milliken

A process and instrumentation diagram for the Milliken coal handling system is provided in Figure 2.6-1.

2.6.2 Task II - Kodak

Process and instrumentation diagrams (P&IDs) for the Eastman Kodak Boiler #15 demonstration site are provided in Appendix 2.6-1.

3.0 **UPDATE OF THE PUBLIC DESIGN REPORT**

The initial proposer for the Micronized Coal Reburn Demonstration program was the Tennessee Valley Authority. The contract was fulfilled by NYSEG when TVA withdrew. These circumstances created a very short lead time to proceed with implementation of technology and the generation of test results. Consequently, the DOE excused this program from the compilation and generation of a Public Design Report and substituted in its stead NYSEG's proposal to the DOE submitted January, 1996.

4.0 **DEMONSTRATION PROGRAM**

4.1 **TEST PLANS, TEST METHODS, ANALYSES OF FEEDSTOCKS; DATA ANALYSES**

Tests were conducted under Task 1, Milliken Station Unit 1 and Task 2, Kodak Boiler #15. Comprehensive reports were produced describing test plans, test methods, analyses of feedstocks and products, and data analyses of results for each of the tests.

4.1.1-4.1.2 **Short-Term and Long-Term Tests**

Milliken Station
1. DB Riley Mill Test
2. CONSOL Reburn Performance
3. CONSOL ESP Performance

Kodak Boiler #15
1. B&W
2. CONSOL Reburn Performance
3. CONSOL ESP Performance

4.2 **OPERATING PROCEDURES**

4.2.1 **Task 1 - Milliken Station**

During micronized coal reburning tests at the Milliken Station, operating procedures were consistent with conventional practice. Mill settings for MCR operations and parameter settings are provided in Appendix 4.2.1.

4.2.2 **Task 2 - Kodak Boiler #15**

Operating procedures for MCR at Kodak's Boiler #15 are provided in Appendix 4.2.2.

4.6 **OPERABILITY AND RELIABILITY**

4.6.1 **Critical Component Failure and Analysis**

4.6.1.1 **Milliken**

Existing equipment was utilized at the Milliken Station. No problems particular to MCR operation were experienced. Two areas of potential concern are water wall tube wastage and mill life.

4.6.1.2 **Kodak**

Certain components of the MCR system at the Kodak site experienced difficulties at times in maintaining stable and long-term operation. Specific items were: wear on the rotary valves for the coal feed to the mills, leakage at the isolation valves that separate micronizing mills A and B, pluggage of the coal feed chute, and vibration of the flue gas recirculation fan.

Two items pertaining to the cyclone boiler at the Kodak site required modification. Specifically, additional oxygen monitors in the economizer were added, and slagging of coal injection was addressed. Wear on the micronizer blades in the Fuller mill was an area that required considerable attention. New wear resistant coatings were located during the program and are now being evaluated.

5.0 **TECHNICAL PERFORMANCE**

A brief summary of the short and long-term test results, effects of operating variables on results, and conclusions for each of the tests is provided below. Appendices 5.0-1 through 5.0-6 contain the full reports.

5.0.1 **Task 1, Milliken Station**

In 1996, NYSEG Corporation contracted DB Riley, Inc. to provide mill system technical support in conjunction with NYSEG's DOE-sponsored Micronized Coal Reburn Demonstration Project, utilizing, as a test site, Unit 1 at NYSEG's Milliken Station.

Reduced load, maximum mill capability, and fineness tests were conducted on January 28 and 29, 1997 on Mill 1A1 serving the boiler's top burner row.

The MPS 150 mills installed at Milliken Station are equipped with planetary gear reducers, hydro-pneumatic roller loading, and hydraulically-driven dynamic classifiers (type SLS). Mills were guaranteed to deliver 18.4 ton/h of pulverized coal at a minimum fineness of 87% thru 200 mesh and 98% thru 100 mesh, when grinding an eastern bituminous coal having a moisture content of 5.6% and grindability of 57 HGI. Previous mill tests at 18.4 ton/h demonstrated a mill product fineness capability of 94% thru 200 mesh and 100% thru 100 mesh with coal having a moisture level of 5.0% and HGI of 55.8.

Mill 1A1 is equipped with Rexroth-supplied back pressure roller loading control valve intended to provide higher and more stable cap-end loading cylinder pressure for better system cushioning.

Some conclusions drawn from the January 28 and 29, 1997 tests are summarized below. The full report is supplied in Appendix 5.0-1.

! Mill 1A1 can operate stably over a load range of 8-12 t/h at elevated classifier cage speeds while producing mill differentials in the range of 20-21+ in. wc.

- ! The higher classifier speeds produce much steeper (more vertical) particle size distributions when plotted on Rosin-Rarmecer probability grids, indicating better sharpness of classification.

- ! Based on observed analog charting of mill differentials, future maximum fineness runs at reduced mill loads in the 8-12 t/h range should have slightly altered classifier speeds.

- ! From these tests, one can now predict a range of mill product fineness values when 1A1 mill is operated in similar fashion over an 8-12 t/h load range.

- ! The special back pressure control valve installed on the HPU of mill 1A1 provides no noticeable improvement in back-pressure cushioning.

An evaluation test program was conducted by CONSOL R&D consisting of a sequence of three test sets: 1) Diagnostic, 2) Performance, and 3) Long-Term. The diagnostic test program consisted of short-term (1-3 hours) optimization tests conducted to obtain parametric data, and to select settings for long-term operation. The selected settings were utilized during performance and long-term testing to achieve the lowest NOx emissions at full boiler load (140-150 MW) while maintaining the required steam conditions, reliable boiler operation and fly ash LOI below 5%. The performance test program assessed a detailed set of operating variables for the reburn configuration. The long-term test program evaluated the long-term (23 days) NOx emissions performance of the reburn configuration, and estimated the annual emissions.

The evaluation test program focused on coal reburning, and utilized, as baseline, the LNCFS-3 configuration which generated the lowest NOx emissions (0.35 lb/MM Btu), while maintaining the fly ash loss on ignition (LOI) below 5%. A primary consideration was given to maintaining reliable boiler operation for power generation. High-volatile bituminous Pittsburgh seam coal was used as both the primary and the reburn fuels during the evaluation.

The following conclusions were derived. A comprehensive report describing the test program is provided in Appendix 5.0-2.

- **Applying Coal Reburning Using LNCFS-3:** Reburning was successfully applied using the existing LNCFS-3 configuration and without installing a separate reburn system. This was accomplished by using the top coal feed as the reburn fuel, and reducing the top burner level air flows by introducing less coal air and auxiliary air flows relative to the LNCFS-3 setting. Furthermore, the impact of reburning was increased by concentrating the over fire air through fewer and higher ports and using finer grind reburn coal (exceeding 70% passing 325 mesh) to maintain LOI below 5%.

- **Overall Effect of Operating Variables:** At the same economizer O_2 level, no single operating variable had a dominant effect on reburning performance. A combination of operating settings (selected for long-term operation) achieved the final results (lowest NOx and reliable operation). Appropriate operating settings for long-term operation were 14-16% reburn coal, 105 rpm top mill classifier speed (corresponds to 70-72% -325 mesh), -5 degrees main burner tilt and 2.8%

economizer O_2. No additional improvement in LOI was observed using higher top mill classifier speeds (relative to the long-term setting of 105 rpm).

- **Coal Reburn Configuration Performance:** Based on performance testing, using 14.4% coal reburn at full boiler load (140-150 MW) reduced NOx emissions from a baseline (LNCFS-3) of 0.35 to 0.25 lb/MM Btu (28% reduction), while maintaining the fly ash LOI below 5% and the boiler efficiency at 88.4-88.8%.

- **Long-Term NOx Performance:** Based on long-term testing consisting of 23 days of continuous measurements, the achievable annual NOx emissions using 15.1% coal reburn were estimated at 0.245 ± 0.011 lb/MM Btu (95% confidence), and the estimated average fly ash LOI was 4.4 ± 0.4%.

- **Experimental Uncertainty:** Based on replicated performance tests and a 95% confidence level, variations in NOx emissions less than 0.006 lb/MM Btu and in fly ash LOI less than 1.5% were assumed to be of no statistical significance. There were large uncertainties with respect to the effects on LOI, possibly because LOI generally varied within a relatively narrow range (between 3% and 5%), in response to the operating variables.

- **Effect of SOFA Tilt:** Variations in the SOFA tilt between 0 and 15 degrees (above horizontal) had minor effects on both NOx emissions and LOI in both LNCFS-3 and reburn configurations.

- **Effect of Reburn Coal Transport Air:** An increase in the reburn coal transport air (top burner primary air), corresponding to a 20% increase in the air-to-fuel ratio from 2.05 to 2.45 (lb/lb), increased NOx emissions from 0.28 to 0.31 lb/MM Btu. The increase in NOx was attributed to less reducing reburn zones with the additional introduction of an oxidant with the reburn fuel.

- **Effect of Top Level Auxiliary Air:** Increasing the top level auxiliary air flow increased both NOx emissions and LOI. The increase in NOx was attributed to less reducing reburn zones as more oxidant was introduced through the auxiliary air nozzle situated directly below the reburn coal nozzle. The increase in LOI was attributed to lower excess air levels in the primary combustion zone as more air was diverted away from the lower burners.

- **Effect of Overall Excess Air:** Increasing the economizer O_2 generated the classical response of higher NOx emissions and lower or stable LOI. The sensitivity was estimated at 0.1 lb NOx/MM Btu per 1% change in O_2 and was relatively independent of the reburn coal fineness.

- **Effect of Reburn Coal Fineness:** Using finer grind reburn coal (top mill) reduced both NOx emissions and LOI. The effect on NOx was significant (relative to the uncertainty level of 0.006 lb/MM Btu) only for relatively large variations in the top mill classier speed (e.g. change of 30 rpm).

- **Effect of Overall Coal Fineness:** Using finer grind coal (all mills) reduced both NOx emissions and LOI.

- **Effect of Main Burner Tilt:** Operating the main burner tilt slightly below the horizontal (about -5 degrees) improved the reburning performance (lower LOI without increasing NOx), relative to the horizontal setting. That was attributed to longer residence times in the furnace prior to over fire air introduction. Overall, the effect was difficult to quantify due to a limited number of tests.

- **Effect of Reburn Coal Fraction:** Decreasing the reburn coal fraction from 25% to 14% decreased NOx emissions from 0.25 to 0.23 lb/MM Btu and had a minor effect on LOI (generally less than 1.5% absolute). The decrease in NOx was attributed to lower excess air levels in the primary combustion zone as more coal was diverted to the lower burners.

- **Effect of Boiler Load:** Reducing the boiler load reduced NOx emissions, and the effect was greater when the second mill was taken out of service. Thus, reducing the boiler load by taking the second mill out of service is a recommended option.

- **Effect of Mill Pattern:** Taking the second mill out of service while maintaining the same boiler load reduced NOx emissions at both high (140 MW) and low (110 MW) boiler loads, possibly due to longer residence times in the primary combustion zone.

The performance of the electrostatic precipitator (ESP) at Milliken while firing a medium-sulfur, bituminous coal was evaluated by CONSOL R&D in September 1998 during injection of micronized coal to reduce NOx formation. No significant effect of MCR on the performance of the Milliken electrostatic precipitator was observed, as measured by removal efficiency or penetration. However, the carbon content of the fly ash increased from 2.4% to 3.7% and the absolute emission increased approximately 30% due to the increase in ESP inlet loading brought about because the micronized coal injected for reburn high in the boiler had a short residence time resulting in more unburned material reaching the ESP than baseline levels. NYSEG had recently rebuilt the ESP to improve its effectiveness. New internals, new computer controlled transformer-rectifier sets, and an additional third field were installed. The plates have a 16-inch spacing. Although there were notable differences in the parameters that affected ESP performance between the initial baseline operation and the micronized coal reburn (MCR) case, the performance, as measured by the removal efficiency, was similar. These results are specific for the wide-plate spacing retrofit of the Milliken ESP. A full report, detailing the ESP evaluation is provided in Appendix 5.0-3.

ABB C-E Services, Inc. conducted thirty-five tests at NYSEG's Milliken Station to assess the achievable level of NOx reduction with the existing firing system using micronized coal. Testing was conducted from March 21 through March 26, 1997. A full description of the 35 tests can be found in Appendix 5.0-4.

5.0.2 **Task 2, Kodak Boiler #15**

An optimization study of the Micronized Coal Reburning System retrofit to Eastman Kodak's #15 boiler was carried out by Babcock & Wilcox, Field Service and Results Engineering departments, between April 13 and April 29, 1998. Tests were performed to evaluate pre- and post-reburn performance relative to NOx reduction, boiler efficiency and superheater performance. Various overfire air port settings were evaluated to deliver optimum combustion efficiency for the reburn system. The combustion stoichiometries in the cyclone, reburn and burn-out zones were optimized to produce the air and fuel flow data necessary to operate the system in automatic control. The study determined the operating load range of the reburn system while not adversely affecting boiler performance. The test data were used to identify the maximum NOx reduction capability of the system and create a NOx vs boiler load profile. The combustion control system was configured to match the emission vs load profile and the boiler was successfully put into automatic operation.

Key results are listed below. A comprehensive report for these tests is provided in Appendix 5.0-5.

! NOx vs Load

NOx emissions could be maintained below 0.60 pounds per million Btu when operating at full boiler load with a reburn heat input of 20% of the total heat input to the boiler. With a baseline NOx at full load of 1.36 pounds per million Btu and a reburn NOx of 0.56 pounds per million Btu, the addition of reburn fuel represents a 59% NOx reduction from the baseline. As load is reduced, the reburn NOx emission rate climbs gradually until it eventually meets the baseline NOx at 320 kpph steam flow.

! Boiler Efficiency

The reburn system has a negative impact on boiler thermal efficiency causing a 1.54% drop at full load. This decrease is a direct result of higher unburned carbon loss. The LOI in the boiler flyash increased from 12.5% without reburn to 41.5% with reburn. This result is different than that found in tests conducted by CONSOL - see Appendix 5.0-6.

! Superheat Performance

The boiler is designed to produce 1425 psi, 900EF steam from a boiler load of 300 kpph to 400 kpph utilizing inter-stage attemperation for superheat temperature control.

The final steam temperature with reburn in service remains within 10EF of the desired 900EF throughout the load range.

An evaluation test program was conducted by CONSOL Inc. and consisted of four test programs (Diagnostic, Performance, Long-Term, and Validation). The diagnostic test program was based on the analysis of results of short-term (1-3 hours) optimization tests conducted by Babcock & Wilcox in order to obtain parametric data. The performance test program was based on characterization testing to assess a detailed set of operating variables. The long-term test program was based on measurements to assess the long-term (two months) NOx emissions performance of the reburn system. The validation test program was based on short-term; (1-3 hours) parametric testing to re-evaluate the performance of the reburn system following long-term testing.

The evaluation included baseline (no reburn) testing for comparison. A primary consideration was given to maintaining reliable boiler operation for power generation. High-volatile bituminous Pittsburgh seam coal was burned during the evaluation, using the same coal as the primary and the reburn fuels.

The following conclusions were derived. A comprehensive report describing the evaluation test program is provided in Appendix 5.0-6.

- **Micronized Coal Reburn Performance:** Based on performance testing, using 17.3% micronized coal reburn (reburn stoichiometry of 0.89) reduced NOx emissions from a baseline (no reburn) of 1.36 to 0.59 lb/MM Btu (57% reduction), increased the fly ash carbon content from 11% to 37%, and reduced the boiler efficiency from 87.8% to 87.3%.

- **Long-Term NOx Performance:** Based on long-term testing, the achievable annual NOx emissions (at 15.6% reburn or stoichiometry of 0.90) were 0.69 ± 0.03 lb/MM Btu (95% confidence), corresponding to a fly ash carbon content of 38% ± 2%. Higher reburn feeds (estimated at 18.4% reburn or stoichiometry of 0.87) would be required for long-term compliance with the 0.6 lb/MM Btu NOx emissions limit.

- **Overall Effect of Reburn Application:** The application of micronized coal reburning reduced NOx emissions and increased the fly ash carbon content. The final NOx emissions mainly depended on the reburn stoichiometry, typically dropping below 0.6 lb/MM Btu at reburn stoichiometries below 0.9 and corresponding to 40-45% carbon in the fly ash, compared to typical baseline (no reburn) NOx emissions of 1.2-1.4 lb/MM Btu and 10-15% carbon in the fly ash. The increase in the fly ash carbon content relative to baseline was partially due to a lower cyclone heat input resulting in lower temperatures and partially due to the staged combustion resulting in shorter residence times under oxidizing conditions. The contribution of reburning alone (assuming no change in the cyclone heat input) to the increase in the fly ash carbon content was estimated at 0-12% (absolute).

- **Effect of Reburn Stoichiometry:** The reburn stoichiometry had a dominant effect on NOx emissions and a significant effect on the fly ash carbon content. Lower reburn stoichiometries reduced NOx emissions and increased the fly ash carbon content. Based on validation testing, NOx emissions as low as 0.41 lb/MM Btu were achievable at maximum reburn utilization (reburn stoichiometry of 0.81), corresponding to 48% carbon in the fly ash.

- **Effect of Cyclone Heat Input:** Based on short-term testing (optimization and validation), lower cyclone heat inputs reduced NOx emissions and increased the fly ash carbon content, attributed to lower temperatures in the primary (cyclone) combustion zone resulting in less thermal NOx formation and less efficient char burnout. The effect on NOx was of minor significance with typical reburn applications (reburn stoichiometries below 0.9). At the same cyclone heat input, the fly ash carbon content was not significantly different with or without reburning, suggesting that in reburn applications, the fly ash carbon content could be maintained at levels similar to baseline by maintaining a high cyclone heat input.

- **Effect of Cyclone Stoichiometry:** Based on short-term (validation), variations in the primary stoichiometry between 1.02 and 1.14 had minor effects on NOx emissions (less than 0.03 lb/MM Btu) and the fly ash carbon content (less than 5%).

- **Effect of Final Stoichiometry:** Based on short-term testing (optimization and validation), variations in the final stoichiometry between 1.05 and 1.16 had no significant effects on NOx emissions or the fly ash carbon content.

- **Reproducibility:** The optimization and the validation test programs produced consistent results with respect to the effects of the operating variables on NOx emissions and the fly ash carbon content. However, the validation tests generated 0.05 lb/MM Btu lower NOx emissions and 4-7% higher fly ash carbon contents than the optimization tests, attributed partially to differences in coal properties, and partially to experimental variability.

Performance testing was conducted by CONSOL Inc. during the week of June 2, 1998 on the Kodak Boiler #15 electrostatic precipitator (ESP) to assess the impact of micronized coal reburn (MCR) on ESP Performance. This test program involved the simultaneous sampling of both the ESP inlet and ESP outlet for particulate mass loading. Four sets of paired inlet and outlet samples were collected for both the baseline and MCR test conditions. Daily composites were made of as-fired coal samples taken incrementally by plant operators during each test period. ESP electrical conditions were manually read from meters on the transformer-rectifier controller cabinets. All of the sampling and data collection was coordinated with the control room operators to assure that the testing was conducted under full load (nominally 400,000 lb/h steam make) and normal operating conditions.

The following conclusions were drawn from the MCR and baseline testing of the Kodak Boiler #15 ESP. A full report is provided in Appendix 5.0-7.

- The ESP removal efficiency did not decline for the reburn tests but actually increased slightly above the measured efficiency for the baseline tests. The average efficiency for the MCR tests was 97.1% vs 95.5% for the baseline tests.

- The MCR operations increased particulate loading to the ESP by 2.8 times the baseline and the loading to the stack increased 1.8 times the baseline.

- Measured ESP particulate removals exceeded the design removal of 94.4 wt % for all the MCR tests and for three of the four baseline tests. Therefore, the MCR operations do not appear to be detrimental to the ESP performance.

- The MCR flue gas particulate was significantly coarser than the baseline particulate. Average particle diameters were: 23 to 25 microns for MCR and 5 to 8 microns for baseline.

- MCR operations increased the fly ash carbon content. For the MCR operations, the fly ash carbon averaged 36.8 wt % vs 11.3 wt % for the baseline operations.

! There are significant differences between the ESP energization levels for MCR and baseline operations. Under MCR conditions, field energizations were significantly higher than under baseline conditions. This helps to explain why removal efficiencies remained high for MCR although particulate loading were several times the baseline values.

6.0 **ENVIRONMENTAL PERFORMANCE**

The environmental impact, methodology for waste stream disposal and potential environmental concerns were addressed in the Micronized Coal Reburn Demonstration for NOx Control Environmental Information Volume which was released under this program. That volume is appended to this report (Appendix 6.0). Several minor differences from the proposed program and the final outcome of the program can be found in an addition to the report entitled "Errata." These differences did not alter the predicted methodologies or outcome.

7.0 ECONOMICS

The MCR technology for NOx reduction was demonstrated on a T-fired boiler at the NYSEG Milliken Station and on a cyclone boiler at Kodak's industrial park. Cost analyses for a generic 300 MWe commercial application of this technology were performed for both types of boilers and are presented here in sections 7.1 (T-fired boiler) and 7.2 (cyclone boiler). Within the accuracy of these estimates, costs for wall fired boilers using MCR technology would be approximately the same as the T-fired boiler.

7.1 T-FIRED BOILER

7.1.1 Economic Parameters

Economics are presented here for a generic 300 MWe T-fired boiler. Since there can be considerable variability within this group, the plant design basis for these economics is shown on Table 7.1–1. The economic parameters used in developing the Micronized Coal Reburning (MCR) economics are shown on Table 7.1-2. These values are consistent with the default parameters outlined in the U.S. DOE Clean Coal Technology Projects General Guidelines for the Final Report - Project Performance and Economics. Alternate values were used where appropriate to be consistent with the design and operation of the MCR process.

7.1.2 Estimated Capital Costs

The total capital requirements for an equivalent 300 MWe (net) T-fired boiler incorporating the MCR technology demonstrated at the Milliken station has been developed using DOE's standard approach to facilitate comparisons with other DOE CCT technologies. The most likely initial application of this technology would be retrofit of existing power stations. However, since existing equipment varies over a wide range of configurations, manufacturers, and age even within the T-fired boiler category, assumptions were made in retrofitting of MCR to a generic 300 MWe plant:

- An existing top row of burners is used without modification for MCR injection.

- One coal pulverizer supplies coal feed to reburn burners.

- An existing coal pulverizer is replaced with a new pulverizer and dynamic classifier to achieve the required coal fineness (70% <325 mesh).

- Space is available for installation of the new coal pulverizer and associated equipment.

- Additional instrumentation and controls would be required including upgrade of the distributed control system (DCS).

The installed cost of this equipment is shown on Table 7.1-3. Since the basis for these values is a retrofit application, no retrofit adjustments are required. These costs are expressed as 1999 dollars.

No allowance was included for funds during construction. It was assumed that a new coal pulverizer could be installed while the power plant was in operation and final ductwork modifications/ connections could be installed during a planned plant outage.

A project contingency of 15% was applied to these costs. No process contingency was applied since the equipment retrofitted is commercially available and successful demonstration of the technology at the NYSEG Milliken Station obviates the need for such a contingency.

The total capital requirement is itemized on Table 7.1-4. Factors were applied to installed equipment costs as delineated on Table 7 .1-2. As shown, the total capital cost for retrofit of MCR to a T-fired boiler is $4.3 MM, or approximately $14/kW. This minimal investment is due to the fact that existing burners can be used for MCR injection. If space is unavailable for installation of a new pulverizer or if the existing burners cannot be used for MCR injection, the costs will be higher. On the other hand, some existing installations already include pulverizers that produce the required fineness. Little capital would be needed in those instances.

7.1.3 Projected Operating and Maintenance Costs

Operating and maintenance costs are shown on Table 7.1-5. These costs are based on the assumptions shown on Table 7.1-1. Fixed operating and maintenance costs include estimates of operating labor, maintenance labor, administration and support and the operating and maintenance materials required for operation of the MCR process.

The only consumable required is an increase in coal consumption to compensate for the heat lost due to the somewhat higher fly ash carbon content (and increased carbon loss). Parasitic power consumption increases due to the power required by the dynamic classifier. Maintenance will be greater for the coal pulverizer mill and classifier in comparison to standard equipment. Overall, these costs are small in comparison to the total O&M costs of the power plant.

7.1.4 Summary of Performance and Economics

The performance and economics of the MCR process for a 300 MWe T-fired boiler application is summarized on Table 7.1-6. Costs were levelized both on a current dollar and constant dollar basis. Economic assumptions are identified in Table 7.1–2. Levelized costs for the 300 MWe unit is $1329/ton of NOx removed on a current dollar basis and $1023/ton on a constant dollar basis. Busbar costs are 0.63 mills/kW on a current dollar basis and 0.49 mills/kW on a constant dollar basis. Capital costs are reported on Table 7.1–4 as $14/kW. These costs assume year-round operation.

7.1.5 Economics Sensitivities

The analysis was conducted for a 300 MWe power plant operating at a 65% capacity factor with an initial NOx level (before MCR) of 0.4 lb/MM Btu. Additional economic analyses were performed to determine the impact of variations in these parameters. These analyses were performed on a constant dollar basis.

As plant size increases, capital and fixed costs per MWe decrease (i.e., economy of scale) while variable costs decrease on a per MW basis. The overall affect is a decrease in the $/ton of NOx removed as the plant size increases as shown on Figure 7.1-1.

Sensitivity to plant capacity factor is shown on Figure 7.1-2. Here the capital costs are fixed. Therefore, increasing the capacity factor increases the quantity of NOx removed for a given capital investment.

Figure 7.1-3 shows the sensitivity to initial NOx level. A fixed percentage level of reduction is assumed for all cases. Therefore, as the initial level is lower, the absolute quantity of NOx removed is lower and vice versa. Therefore, the $/ton of NOx removed decreases as the initial NOx level increases.

7.2 CYCLONE BOILER

7.2.1 Economic Parameters

The economics presented here are for a generic 300 MWe cyclone boiler. Since there can be variability within this group, the design basis for these economics is shown on Table 7.2-1. The economic parameters used in developing the Micronized Coal Reburning (MCR) economics are the same as used for the T-fired boiler shown on Table 7.1-2. Alternate values were used as appropriate to be consistent with the design and operation of the MCR process.

7.2.2 Estimated Capital Costs

The total capital requirements for an equivalent 300 MWe (net) cyclone boiler incorporating the technology demonstrated on the 60 MWe (net) industrial boiler at Kodak Park has been developed using DOE's standard approach to facilitate comparisons with other DOE CCT technologies which are outlined in the U.S. DOE General Guidelines for the Final Report - Project Performance and Economics. The most likely initial application of this technology would be retrofit of existing power stations rather than new plant installations. The assumptions made in the economic analysis are as follows:

- Space is present on the boiler for installation of both MCR injectors and OFA ports at locations allowing sufficient residence time for completion of the combustion reactions.

- A single, dedicated coal pulverizer supplies coal feed to the MCR coal injectors.

- A new pulverizer and dynamic classifier is installed to achieve the required coal fineness.

- Space is available for installation of the new coal pulverizer and associated equipment.

- Additional instrumentation and controls are required including upgrade of the distributed control system (DCS).

The installed cost of this equipment is shown on Table 7.2-2. Since the basis for these values is retrofit application, no retrofit adjustments are required. Therefore, no retrofit adjustments are applicable. The nominal year of these costs is 1999.

No allowance was included for funds during construction. It was assumed that a new pulverizer could be installed with the power plant in operation and final ductwork modifications/connections could be installed during a normal plant outage.

A project contingency of 15% was applied to these costs. However, no process contingency was applied since the successful demonstration of the technology at Kodak Park obviates the need for such a contingency and the equipment retrofitted is commercially available.

The total capital requirement is itemized on Table 7.2-3. Factors were applied to installed equipment costs as delineated on Table 7.1-2. As shown, the total capital cost for retrofit of MCR to a cyclone boiler is $16.9 MM or approximately $56/kW. These costs are consistent with projections made by Babcock & Wilcox based on MCR testing performed at Wisconsin Power & Light's Nelson Dewey Station[3]. Again, these costs are consistent with the assumptions made. If space is unavailable for installation of a new pulverizer or installation of MCR injectors or OFA ports, the costs will be higher. Costs are higher in comparison to the T-fired boilers (see above) because existing burners in the T-fired unit could be used for MCR injection and OFA ports were assumed to be available as a consequence of prior retrofit of low NOx burners.

7.2.3 Projected Operating and Maintenance Costs

Operating and maintenance costs are shown on Table 7.2-4. The costs are based on the assumptions shown on Table 7.1-1. Fixed operating and maintenance costs include estimates of operating labor, maintenance labor, administration and support and the operating and maintenance materials required for operation of the MCR process. The only material required is coal. Coal consumption increases slightly to

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[3] Demonstration of Coal Reburning for Cyclone Boiler NOx Control, Final Project Report. DOE/PC/89659-T16, Babcock & Wilcox Co., Barberton, OH. Energy Services Div., Feb. 1994.

account for the somewhat higher fly ash rate and carbon content (and increased carbon loss). Parasitic power consumption increases due to the power required by the coal pulverizer and dynamic classifier. Maintenance will be somewhat greater for the pulverizer mill and classifier in comparison to standard equipment.

Long term testing was not conducted as part of the Milliken MCR test program. Because of the reducing atmosphere produced by MCR, the potential exists for boiler tube corrosion between the MCR injection ports and the OFA ports. This reducing environment could increase forced outages and maintenance costs substantially. No net changes in plant availability were assumed in the economics presented here.

7.2.4 Summary of Performance and Economics

Table 7.2–5 summarizes the performance and economics of the MCR process for a 300 MWe cyclone boiler commercial application. Costs were levelized both on a current dollar and constant dollar basis. Cost assumptions were identified in Table 7.1–2. Levelized costs for the 300 MWe unit are $741/ton of NOx removed on a current dollar basis and $571/ton on a constant dollar basis. Even though the capital required is greater, these costs are lower on a $/ton removed basis compared to the T-fired boiler (see above). This is due to the much higher NOx removal on the cyclone boiler resulting from 50% NOx reduction compared to 25% with the T-fired configuration. Also, because of the much higher initial NOx level, the absolute NOx reduction with the cyclone boiler is six times greater than the T-fired boiler configuration.

Busbar costs are 2.2 mills/kW on a current dollar basis and 1.7 mills/kW on a constant dollar basis. Capital costs are reported on Table 7.2–3 as $56/kW. This compares to $14/kW for the T-fired boiler configuration. These costs assume year-round operation.

7.2.5 Effect of Variables on Economics

This analysis was conducted for a 300 MWe power plant operating at a 65% capacity factor with an initial NOx level (before MCR) of 1.25 lb/MM Btu. An analysis was performed to determine the impact of varying these parameters on the resulting economics.

As plant size increases, capital and fixed costs per MWe decrease (i.e. economy of scale). Variable costs increase proportionally. The overall affect is a decrease in the $/ton of NOx removed as the plant size increases as shown on Figure 7.2-1.

Sensitivity to plant capacity factor is shown on Figure 7.2-2. Here, the capital costs are fixed. Therefore, increasing the capacity factor increases the quantity of NOx removed for a given capital investment and thus lowers the cost per ton of NOx removed.

Figure 7.2-3 shows the sensitivity to initial NOx level. A fixed level of reduction is assumed for all cases. Therefore, as the initial level is lower, the absolute quantity of NOx removed is lower and vice versa. Therefore, the $/ton of NOx removed decreases as the initial NOx level increases.

8.0 COMMERCIALIZATION POTENTIAL AND PLANS

8.1 MARKET ANALYSIS

8.1.1 Applicability of the Technology

The test boilers used for demonstration in this program were a 60 MW cyclone boiler and a 150 MW tangentially-fired boiler. These units are typical of a large portion of the nation's utility operating base. Thus, there is a potential for wide application of the technology.

Although demonstrated on a cyclone-fired and a tangentially-fired unit, the technology should be equally applicable to a wall-fired unit. The successful demonstration of the DB Riley MPS with dynamic classifiers indicates that the technology should be applicable to large central stations.

The technology can use virtually any coal that can be micronized.

Although primarily developed as a means for decreasing NOx emissions from coal-fired furnaces, the MCR technology has several other potential benefits which will make it attractive for many operators of coal-fired units. Among the possible benefits are:

- Increased capacity on mill-limited units.
- Providing back-up for existing pulverizers, while having no negative impact on furnace performance.
- Improved efficiency due to lower excess air and decreased loss on ignition.
- Competitive capital, operating, and maintenance costs.
- Ease of retrofit, since the reburn burners and overfire air ports are the only furnace wall penetrations required. Existing burners and registers can be modified at minimal expense for fuel/air staging.
- Ability to fire low-sulfur, low-cost subbituminous coals as a reburn fuel.
- Up to 30% reduction in existing pulverizer throughput, thus permitting classifiers to be adjusted for a significant improvement in coal fineness.
- Improved steam and superheat temperature at low load, as a result of firing micronized coal in the upper furnace and rapid devolatilization and char burnout of the reburn fuel.

The combination of micronized coal and reburning for NOx control are a natural fit for existing older fossil units. Together, they provide flexibility and economies of scale that are unattainable with other NOx control technologies.

8.1.2 Market Size

The primary competing technology for NOx control is low-NOx burners. Although low-NOx burners will meet the current emission requirements, the benefits of MCR technology will allow it complete effectively with low-NOx burners. These benefits include the use of the micronized coal system for start-up and low-load operation, and restoring mill-limited units to rated capacity. Installing MCR technology will reduce the load on existing mill systems, improve carbon burnout, reduce excess air, and increase unit efficiency. The technology is expected to be competitive from a capital and operating standpoint with low-NOx burner applications.

Despite slow growth of electric power demand and a corresponding decrease in generating plant construction during the 1980s, demand for electricity is expected to continue to increase at a rate that will not only require new generating capacity but will put additional demands on the existing coal-fired generating base. Recently, the Electric Power Research Institute (EPRI) compiled a listing of 75 MW to 300 MW coal-fired units that were built in the U.S. between 1945 and 1965. This list totals 389 units with nearly 60 GW of capacity. Although they will reach their 40-year life spans between 1985 and 2005, these units are candidates for retrofitting and continued operation, either as baseload or peaking units. As new generating capacity is added, this will further relegate the older installed base to cyclic duty. Benefits of the MCR technology will best be realized on this boiler population. The technology will not only meet the NOx emission requirements but will allow the operation of these units on low load while firing only coal, thereby reducing operating costs and ultimately the cost of electricity delivered to the end user.

It is expected that the MCR technology could capture up to 15% of the NOx control market. This is based on the premise that this technology not only allows the utilities to meet NOx emission requirements but also gives them operating benefits that low-NOx burners and other competing technologies do not.

8.1.3 Market Barriers

NOx reductions as high as 56% were demonstrated in this program. However, the current proposed EPA standard for possible implementation by May 2003 calls for a reduction to achieve 0.15 lb/MM Btu NOx emissions. MCR operations have been reported to reduce NOx by as much as 65%. In order to meet the EPA regulation (and the state implementation plans, SIPs) MCR will have to be augmented with other technologies (for example selective non-catalytic reduction) or replaced all together (by selective catalytic reduction, for example). Therefore, MCR will be limited in application for commercialization to wall-burning facilities which are under a “bubble” where the sum total of reductions required can be met by inclusion of MCR with other technologies, or where the 65% NOx reduction achievable with MCR alone is sufficient to achieve 0.15 lb/MM Btu NOx emissions.

8.1.4 Economic Comparison with Competing Technologies - T-fired

Micronized Coal Reburning (MCR) is one of several technologies that can be used to reduce NOx emissions from coal-fired boilers. Others are gas reburning, Selective Non-Catalytic Reduction (SNCR), and Selective Catalytic Reduction (SCR). Levelized costs recently reported in the open literature are shown for these technologies in comparison to Micronized Coal Reburning on Table 8.1-1 based on costs.

On a levelized cost per ton of NOx removed, gas reburn is the most expensive while MCR and SCR costs are comparable. Gas costs were assumed to be $3/MM Btu.

Costs shown on Table 8.1–1 assume year-round operation of each technology. However, NOx reduction may only be required during the summer ozone season (May–September). Under this scenario, levelized $/ton of NOx removed will increase for each technology. The smallest increase will be for those technologies with the least capital investment. MCR NOx reduction economics would be particularly attractive in those cases where a 25% NOx reduction is acceptable.

8.1.4 Economic Comparison with Competing Technologies - Cyclone

Micronized Coal Reburning (MCR) is one of several technologies that can be used to reduce NOx emissions from a cyclone boiler. Others are gas reburning, Selective Non-Catalytic Reduction (SNCR), and Selective Catalytic Reduction (SCR). Levelized costs for these technologies are shown on Table 8.1–2 in comparison to Micronized Coal Reburning based on costs recently reported the open literature.

This analysis assumed a gas cost of $3/MM Btu. On a levelized cost per ton of NOx removed, SNCR is the most expensive while MCR is the least expensive. However, MCR alone may not be able to achieve anticipated future NOx emission limits. The high level of NOx reduction with SCR may make it the technology of choice.

Costs shown on Table 8.1–2 assume year-round operation of each technology. However, NOx reduction may only be required during the summer ozone season (May – September). Under this scenario, levelized $/ton of NOx removed will increase for each technology. The smallest increase will be for those technologies with the least capital investment. Ultimately, the technology selected must not only be economical but also be able to achieve the NOx reduction necessary to meet environmental limits.

8.2 COMMERCIALIZATION PLANS

Although NYSEG and Kodak do not expect to have any financial interest in the commercialization of this technology, they have required that each participant have a commercialization plan. NYSEG and Kodak are committed to the success of these commercialization efforts and will allow use of the demonstration facility in each of the technology vendor's business plans. NYSEG and Kodak are also committed to an unbiased assessment of the micronized coal reburn technology and to the communication of the results of this technology throughout the industry.

8.2.1 Commercialization Approach

NYSEG and Kodak are sponsoring this Micronized Coal Reburn Demonstration as end-users and would not have the responsibility for the commercialization of this technology. NYSEG, however, has obtained an agreement with both Fuller Corporation (Fuller) of Bethlehem, Pennsylvania and DB Riley, Inc. of Worcester, Massachusetts to develop this technology on a commercial basis. Both have agreed to enter into a cooperative agreement and repayment plan that is in agreement with the requirements of the PON.

The commercialization of this technology is planned by three major subcontractors - Fuller, DB Riley and Energy and Environmental Research Corporation (EER) - with each company maintaining its expertise in the technology it is providing to the micronized coal reburn project.

The project team also has identified a sufficiently large number of other coal-fired units in operation that would benefit from micronized coal reburning and the additional benefits that this technology provides. This technology can be applied to all coal-fired units, including wall-fired, tangentially-fired, cyclone, and large stoker-fired units. There is also no scale-up limit on the size of coal-fired units to which this technology can be applied. Extremely large units may require the use of an indirect-fired micronized coal system; however, this technology is available and has been demonstrated in Europe.

The commercialization of the micronized coal reburn for NOx control will be through a joint effort of two major subcontractors, Fuller and EER. The team will jointly market the technology and each will retain the responsibility for its area of expertise. Fuller will be responsible for the coal preparation and delivery systems, and EER will be responsible for the reburn and furnace technology. As the market expands, a separate group under either EER or Fuller will have the sole responsibility of marketing and pursuing the business sector. The facilities of both companies would be drawn upon, as well as the technical expertise of both companies to accomplish this.

The major subcontractors, responsible for the commercialization of this technology, are an excellent fit because both companies serve the electric utility industry. Fuller is supplying micronized coal systems to the electric utility industry to displace gas and oil as the start-up and low-load stabilization fuel; and EER provides a complete line of gas reburn technology and environmental services for the electric utility industry. Both companies maintain test facilities that include combustion tests, coal preparation and classification, as well as routine chemical and combustion-related testing. The team members are jointly pursuing the micronization and application of ultra fine sorbents to various SO_2 removal technologies such as direct furnace sorbent injection, dry scrubbing, and sorbent preparation for various wet and dry SO_2 removal technologies.

One of the prime subcontractors responsible for the commercialization of this project is Fuller. Fuller has purchased MicroFuel Corporation and has established it as major division of the corporation. Fuller is committed to serving the utility market and providing the financing and support required to accomplish commercialization of this technology. Also, the Fuller technology being used to micronized coal for reburning has four US patents. EER, another subcontractor responsible for commercialization, has completed demonstration tests of three gas reburning systems on coal-fired utility boilers under the DOE's Clean Coal Technology Program Rounds I and III. These demonstration tests have shown that gas reburning is consistent in reducing NOx by 60 to 75 percent, with no adverse operational or boiler durability impacts. Both companies are working together in several areas and are considering joint efforts in several areas other than the micronized coal reburn technology. Both companies have the resources and facilities for engineering, manufacturing, and marketing of their individual products.

As stated in the Model Repayment Agreement, the group plans to begin marketing the micronized coal reburn technology. At that time, the formation of a dedicated group to serve this market will be developed and will be under the direction of one of the major subcontractors. Other plans include marketing the micronized coal reburn technology to the industrial market sector for NOx control on smaller coal-fired units, both pulverized and stoker-fired.

Development of this technology will be accomplished in the normal course of business of both companies. The major area of development will be the design of a larger MicroMill™ to serve reburning applications on large central station units. This could be accomplished through the development of indirect-fired systems to meet maximum reburn firing rates at full load and regenerate the micronized coal supply during off-peak loads. Indirect-firing technology is in operation and is accepted in most European countries, and the team believes it has application for Micronized Coal Reburning.

To demonstrate the value of larger mill designs for micronized coal generation, DB Riley, Inc. has aligned with NYSEG to demonstrate Micronized Coal Reburn Technology using MPS mills and dynamic classifiers at Milliken Station.

DB Riley Inc. is committed to working with NYSEG and its team members on the Department of Energy's Clean Coal Demonstration Program. Toward this end, Riley will provide mill and dynamic classifier expertise and equipment to the project at cost. Riley is also willing to negotiate a repayment contract with the DOE for all mills and dynamic classifiers sold for micronized coal reburn retrofit applications to tangentially fired boilers. The work will be performed in two (2) phases. In Phase I, DB Riley will evaluate and set up the mill and dynamic classifier system for micronized coal reburn operation in the top level of burners. In Phase II, DB Riley will review the reburn system, design and install coal pipe modifications, and participate in the mill and dynamic classifier system testing.

The senior management of these major subcontractors have made a commitment to the commercialization of the Micronized Coal Reburn System. Evidence of their support for this demonstration project is shown by their respective commitment letters included as Exhibits in Section VII.

It is the strategic plan of the three major subcontractors responsible for the commercialization of their technology to support the electric utility industry in the area of micronized coal for displacement of liquid and gaseous fuels in the utility market sector. The development of the Micronized Coal Reburn technology is only an extension of the current market plans and corporate management of all three companies are committed to this market sector.

The three major subcontractors participating in commercializing the micronized coal technology are dedicated and committed to this technology. Fuller and its investors have spent many years and several millions of dollars developing, patenting, and marketing the MicroFuel MicroMill™ System to serve the electric utility market for low-load and start-up applications. This investment includes research and development facilities, full-size demonstration units, and personnel to meet the company's strategic plans and goals. The other major participant, EER, is also dedicated to serve this market in the air pollution control sector. They also have invested substantial time and money in full-size combustion test facilities, and other electric utility-related air pollution control and management solutions. They currently offer a wide variety of products and services to serve this market and the addition of the Micronized Coal Reburn technology would complement their current products and services. DB Riley, Inc. is a leading designer, manufacturer and constructor of steam generating, fuel burning equipment and power systems. Riley's product line consists of the Riley Turbo and wall-fired furnaces for utility power generation, low NOx burners, Riley Ball Tube, MPS Mill and Atrita pulverizing systems, SLS Classifiers, shop-assembled and field erected industrial boilers, fluidized bed combustion systems for boilers, traveling and stationary grate stokers, mechanical feeders and refuse firing systems. Aftermarket offerings, through Riley's Power Services Division, include the Boiler Availability Improvement Program, Team Inspection Service, Maintenance Agreements, the Annual Parts Inventory Program, plus fuel conversions and equipment repairs. DB Riley is committed to the development and commercialization of coal reburn technology. This program is a further application of DB Riley firing systems. Under the US DOE Low Emission Boiler System (LEBS) program, they are developing an advanced coal fired low-NOx slag tap combustion system. This system utilizes coal reburning technology to meet stringent NOx emission and carbon conversion requirements.

9.0 **CONCLUSIONS AND RECOMMENDATIONS**

Six broad objectives were established at the onset of this contract (see Section 1.3.1). Each of these objectives was addressed and the following conclusions and recommendations are made:

The operating performance was established for the two plants that were part of the study (the Kodak cyclone boiler and the Milliken tangentially-fired boiler) when micronized coal was utilized under reburn conditions. It was shown at Milliken that no single operating variable had a dominant effect on reburning performance. A combination of operating settings was used to achieve NOx reduction. No significant effect of MCR on collection efficiency of the ESP was observed. At Kodak, the application of micronized coal reburning was evaluated as a function of NOx reduction and loss on ignition (LOI) of the ash. Reburn stoichiometry, cyclone heat input, and cyclone stoichiometry were examined and found to affect both NOx and LOI. ESP operation was evaluated. Average particle removal efficiency during MCR operation was greater than for baseline operations.

The long-term reliability of the systems and materials utilized in micronized coal reburning was demonstrated. At Milliken, existing equipment was utilized and no operational problems were associated with MCR operations. At Kodak, certain components of the system experienced wear including rotary valves and mill components. New wear-resistant coatings need to be further evaluated.

A direct comparison of the Fuller MicroMill™ and the DB Riley MP S150 (with dynamic classifier) MCR systems, would be technically inappropriate.

Confirming data from two full-scale furnaces were obtained demonstrating that the MCR system achieved its objectives of reducing NOx emissions. MCR was shown to be successful in reducing NOx for both the Kodak cyclone boiler and the Milliken Station tangentially-fired boiler. The objective of 50% NOx reduction on the cyclone boiler was met and exceeded with a demonstrated 59% reduction. The low NOx baseline (0.35 lb/MM Btu) from the Milliken boiler was further reduced to 0.25 lb/MM Btu (a 28% reduction) with MCR, meeting the project objective.

Boiler performance was documented over a sufficiently long period to identify trends in emissions and boiler behavior when micronized coal is used in a reburn application. However, long-term operation to confirm observed trends and demonstrate system flexibility is recommended.

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Table 1.2.1.4-1 COAL REBURNING SYSTEM PROCESS DESIGN BASIS FOR KODAK BOILER #15

Parameter	Units	Value
Load		
Steam Flow	lb/hr	440,000
Zone Stoichiometry		
Primary Zone		1.13
Reburning Zone		0.79
Burnout Zone		1.15
Reburning Fuel	lb/hr	12,000
Transport Type		FGR
Transport Flow	lb gas/lb fuel	1.25
Total FGR Use		5.8%

Table 1.2.1.4-2 COAL ANALYSIS FOR KODAK MCR DESIGN

Parameter	Units	Value
Proximate Analysis:		
Carbon	wt. %	73.38
Hydrogen	wt. %	4.94
Nitrogen	wt. %	1.33
Sulfur	wt. %	2.25
Oxygen	wt. %	4.84
Chlorine	wt. %	0.11
Ash	wt. %	7.15
Moisture	wt. %	6.00
Total	·	*100.00*
Higher Heating Value	Btu/lb	13,192

Table 1.2.1.4-3 COAL REBURNING MATERIAL BALANCE FOR MAXIMUM BOILER LOAD (440,000 LBS/HR) KODAK BOILER #15 DESIGN

STREAM NUMBER	1	2	3	4	5	6	7	8	9	10
DESCRIPTION	Primary Fuel: Coal	Coal Combustion Air	Reburning Fuel: Coal	Reburning Fuel Transport	Overfire Air	Boiler Bottom Ash	Economizer Hopper Ash	Air Heater Leakage	ESP Ash	Flue Gas to Stack
GAS SIDE:										
Air (lbs/hr)		291,779			130,884			0		
Air (SCFM)		65,008			30,210			0		
Natural Gas (lbs/hr)										
Natural Gas (SCFM)										
Flue Gas (lbs/hr)				32,000						473,445
Flue Gas (SCFM)										94,825
SOLID SIDE:										
Fuel (lbs/hr)	36,539		12,000							
Fuel Inerts (lbs/hr)	1,898		858			1,424	38		1,295	
Total Waste Solids (lbs/hr)	1,898		858			1,424	38		1,295	

Table 1.2.1.4-4 REBURNING SYSTEM DESIGN PARAMETERS FOR KODAK BOILER #15

Parameter	Units	Value
Reburning Fuel		
Elevation		226'
Number of Nozzles		8
Nozzle Size		
Furnace Outlet[1]	inches	3.6
Pipe Size	inches	5.0
Coal Flow		
Maximum	lb/hr	12,000
Minimum	lb/hr	2,500
Transport Flow	lb/hr	32,000
Velocity Head[2]		
Nozzle Outlet	in H_2O	16.5
Overfire Air		
Elevation		247' 9"
Number of Nozzles		4
Port Size		
Inner Passage		5.19
Outer Passage		11.37
Outer Diameter	Inches	12.5
Flow Rate		
Maximum		140,000
Velocity Head[3]		
Inner Nozzle	in H_2O	25
Outer Nozzle	in H_2O	21

[1] Equivalent outlet diameter.
[2] Estimated, does not include loss across injector body.
[3] Estimated, does not include loss across OFA assembly.

Table 2.2-1

Milliken Station Unit 1 Post Retrofit
Process Equipment

<u>Mills</u>	Type Quantity Performance	Riley Stoker MPS 150 4 36,800 lb/h at 57 HGI Coal
<u>Classifiers</u>	Type Quantity Performance	Dynamic, Riley Stoker SLS 4 93% -200 mesh
<u>PA Fans</u>	Type	Centrifugal Design, Buffalo Forge
<u>Feeders</u>	Type Quantity Performance	Gravimetric, Stock Equipment 4 20 t/h
<u>Burners</u>	Type	ABB CE LNCFS-3

Table 2.5-1

Milliken Station Process Parameter Data for Long Term Test - 9/7/98 - 12/19/98

Mill Settings

Parameter	1A1 Mill	1B2 Mill	1A3 Mill	1B4 Mill
Coal Damper, %	60	80-85	80-85	80-85
Class. Speed, rpm	105-108	Auto	Auto	Auto
Fuel Flow, tph	8	Auto	Auto	Auto
Grind Force	1200-1500	Auto	Auto	Auto
PA Fan Bias	0	0	0	0

Parameter	Settings
Load, Net MW	120-150
Plant O_2, %	3.2-3.4
Reheat Tilt, Degrees	-5
SOFA Tilt, Degrees	0
Top SOFA, %	35
Mid SOFA, %	35
Low SOFA, %	35
Top CCOFA, %	0
Low CCOFA, %	0
Furn. to WB Ratio	3.6-4.2
Aux to CFS Air Bias	-60
Level 1 Aux Air, %	20
Level 1 CFS, Air, %	10
Level 2 Aux Air, %	20
Level 2 CFS Air, %	10
Level 3 Aux Air, %	20
Level 3 CFS Air, %	10
Bottom Aux Air, %	20

Table 2.5-2
Process Streams
Kodak Boiler #15

Line No.	System	Fluid	Operating Pressure, inches H_2O	Operating Temperature, EF	Design Flow, lb/hr	Operation Flow, lb/hr
1	Overfire Air from Boiler Air Heater	Air	48	685	70,000 EA	54,000
2	Overfire Air to Air Injectors	Air	40	685	140,000	108,000
3	Transport Gas from ESP	Flue Gas	(-)4	350	30,000	28,000
4	Transport Gas to Flue Gas Heater	Flue Gas	68	380	15,000 EA	14,000
5	Transport Gas to Micromill	Flue Gas	60	380-400	12,500 EA	12,000
6	Transport Gas to Classifier	Flue Gas	60	380-400	2,500 EA	2,000
7	Coal Piping from Classifier	Flue Gas & Coal	45	150-200	25,000 EA	20,000-24,000
8	Coal Piping to Splitter	Flue Gas & Coal	40	150-200	40,000	38,000
9	Coal Piping to Coal Injectors	Flue Gas & Coal	30	150-200	5,000	4,750
10	Coal to Micromill	Coal	0	Ambient	10,000	6,000-10,000

Table 7.1–1
Parameters Used in T-fired Boiler MCR Economic Evaluation

Boiler Type	T-fired
Plant Capacity (MWe)	300
Coal Heating Value (Btu/lb)	12,900
Plant Capacity Factor (%)	65
Annual Coal Consumption (ton)	629,000
Plant Heat Rate (Btu/KWh)	9,500
% of Coal Through Reburn Burners	15
Initial NOx Level (lb/MM Btu)	0.4
NOx Reduction (%)	25
MCR Coal Conveying Fluid	Air
No. of MCR Burner Rows	1
No. of Coal Mills/Row	1
Increase in Fly Ash LOI (%) due to MCR (absolute)	5
Increase in Fly Ash Rate (%) due to MCR (absolute)	10
Prior Retrofit of Low NOx Burners	Yes
Prior retrofit of overfire air (OFA)	Yes
Ash in Coal (%)	10

Table 7.1–2
Economic Parameters [a]

ITEM	UNITS	VALUE
Cost of Debt	%	8.5
Dividend Rate for Preferred Stock	%	7.0
Dividend Rate for Common Stock	%	7.5
Debt/Total Capital	%	50.0
Preferred Stock/Total Capital	%	15.0
Common Stock/Total Capital	%	35.0
Income Tax Rate	%	38.0
Investment Tax Credit	%	0.0
Property Tax & Insurance	%	3.0
Inflation Rate	%	4.0
Discount Rate (with Inflation)	%	7.93
Discount Rate (without Inflation)	%	3.744
Escalation of Raw Materials above Inflation	%	0.0
Construction Period	Days	90
Remaining Life of Power Plant	Years	15
Year for Costs Presented in this Report	-	1999
Construction Downtime	Days	0
Royalty Allowance (% of Total Capital)	%	0.0
Capital Charge Factor		
Current Dollars	-	0.160
Constant Dollars	-	0.124
O&M Levelization Factor		
Current Dollars	-	1.314
Constant Dollars	-	1.000
Sales Tax Rate	%	5.0
Cost of Freight for Process Equipment	%	2.0
General Facilities/Total Process Capital	%	10.0
Engineering & Home Office/Total Proc. Cap.	%	10.0

[a] Based on default parameters outlined in the U.S. DOE Clean Coal Technology Projects General Guidelines for Final Report - Project Performance and Economics.

Table 7.1–3
Major Equipment Costs for Equivalent 300 MWe T-Fired Boiler

Item No.	Item Name	F.O.B. Equipment Cost	Sales Tax	Freight	Field Material	Field Labor	Total	No. Of Units	Total Cost
CM-301	Coal Mill	$964,995	$48,250	$19,300	$48,250	$644,946	$1,725,740	1	$1,725,740
CM-302	Coal Feeder	$55,930	$2,797	$1,119	$2,797	$11,186	$73,828	1	$73,828
	I & C	$294,269	$14,713	$5,885	$14,713	$191,275	$520,857		$520,857
	Electrical Systems	$270,199	$13,510	$5,404	$13,510	$469,374	$771,996		$771,986

Table 7.1-4
TOTAL MCR CAPITAL REQUIREMENT
300 MWe T-Fired Boiler

Area No.	Total Installed Equipment Cost	$ MM	$/KW
300	Coal Sizing & Injection	1.80	6.0
300	Electrical & I&C	1.29	4.3
A	Total Process Capital	3.1	10.3
B	General Facilities, 10% of A	0.3	1.0
C	Engineering & Home Office @ 10% of A	0.3	1.0
D	Project Contingency (15% of A+B+C)	0.6	1.9
E	Total Plant Cost	4.3	14.2
F	Allowance for Funds During Construction	0.0	0.0
G	Total Plant Investment	4.3	14.2
H	Royalty Allowance	0.0	0.0
I	Preproduction Costs (1 month of startup)	0.02	0.08
J	Inventory Capital	0.0	0.00
K	Initial Catalyst & Chemicals	0.0	0.00
L	Subtotal Capital	4.3	14.3
M	Cost of Construction Downtime	0	0.0
N	Total Capital Requirement	4.3	14.3

Table 7.1-5
MCR Operating and Maintenance Costs
300 MWe T-Fired Boiler

Fixed O&M Costs	Units	Quantity	$/Unit	$ MM/Yr
Operating Labor Maintenance Labor Maintenance Material Administration/Support Labor	Man- hr/yr	832	23	$0.02 $0.05 $0.07 $0.04
Subtotal Fixed Costs				$0.18
Variable Operating Costs				
Fuels Coal Increase (due to increase in FA LOI)	ton/yr	3657	30	$0.11
Utilities Electric Power	kWh/yr	169,827	0.05	$0.01
Subtotal Variable Cost				$0.12
TOTAL O&M COST (FIXED+VARIABLE)				$0.30

Table 7.1-6
300 MWe T-FIRED BOILER
SUMMARY OF PERFORMANCE AND COST DATA

Power Plant Attributes	Units		Value
Plant Capacity, Net	MWe		300
Power Produced, Net	10^9 kWh/yr		1.71
Plant Heat Rate	Btu/kWh		9,500
Plant Life	yr		15
Capacity Factor	%		65
Coal Feed	10^6 Ton/yr		0.629
Reburn Coal as % of Total Coal Feed	%		15

Emissions Control Data	Units	SO_2	NOx	TSP
Removal Efficiency	%		25	
Emission Standard	lb/MM Btu		0.15	
Emissions Without Controls	lb/MM Btu		0.40	
Emissions with Controls	lb/MM Btu		0.30	
Amount NOx Removed	Tons/Yr		811	

	Current Dollars		Constant Dollars	
Levelized Cost of Power	Factor	Mills/kWh	Factor	Mills/kWh
Capital Charge	0.16	0.40	0.124	0.31
Fixed O&M Cost	1.314	0.14	1.00	0.11
Variable Operating Cost	1.314	0.09	1.00	0.07
Total Cost		0.63		0.49
Levelized Cost - NOx Basis	Factor	$/Ton Removed	Factor	$/Ton Removed
Capital Charge	0.16	846.22	0.124	655.98
Fixed O&M Cost	1.314	291.40	1.00	221.77
Variable Operating Cost	1.314	191.41	1.00	145.67
Total Cost		1,329		1,023

Table 7.2–1
Parameters Used in Cyclone Boiler MCR Economic Evaluation

Boiler Type	Cyclone Fired
Plant Capacity (MWe)	300
Coal Heating Value (Btu/lb)	12,900
Plant Capacity Factor (%)	65
Annual Coal Consumption (ton)	629,000
Plant Heat Rate (Btu/KWh)	9,500
% of Coal Through Reburn Burners	20
Initial NOx Level (lb/MM Btu)	1.25
NOx Reduction (%)	50
MCR Conveying Fluid	Recycled Flue Gas
No. of MCR Injection Rows	1
No. of Mills for MCR Injection	1
Increase in Fly Ash LOI (%)	10
Increase in Fly Ash Rate (%)	20
Boiler Efficiency (%)	87
Prior retrofit of overfire air (OFA)	No
Ash in Coal (%)	10

Table 7.2–2
Major Equipment Costs for a 300 MWe Cyclone Boiler

Item No.	Item Name	Equipment Cost F.O.B.	Sales Tax	Freight	Field Material	Field Labor	Total	No. of Units	Total Cost
CM-201	Coal Mill	$1,107,294	$53,515	$21,406	$53,515	$715,321	$1,914,050	1	$1,914,050
CM-301	MCR Injectors	$32,596	$1,630	$652	$1,630	$21,187	$57,694	30	$1,726,076
	MCR Injection Panels	$17,647			$882	$11,471	$30,000	30	$897,526
CM-302	OFA Ports	$145,500	$7,275	$2,910	$7,275	$94,575	$257,535	12	$3,090,423
	OFA Panels	$17,647			$882	$11,471	$30,000	12	$359,999
CM-303	Coal Feeder	$70,000	$3,500	$1,400	$3,500	$45,500	$123,900	1	$123,900
	Piping/ Duct Mods	$336,381			$67,276	$941,868	$1,345,525	1	$1,345,525
	Pulverizer Building	$76,179	$3,809	$1,524	$10,883	$141,475	$217,654	1	$217,654
	I & C	$316,213	$15,811	$6,324	$15,811	$205,539	$559,697	1	$559,697
CM-304	FGR Fan	$154,514	$7,726	$3,090	$7,726	$41,073	$214,130	2	$428,259
CM-305	Emergency Cooling Fan	$19,127	$956	$383	$956	$5,084	$26,506	1	$26,506
	Electrical Systems	$308,809	$15,440	$6,176	$44,116	$507,770	$882,312	1	$882,312

Table 7.2-3

300 MWe CYCLONE BOILER TOTAL CAPITAL REQUIREMENT

Area No.	Total Installed Equipment Cost	$ MM	$/KW
300	Coal Sizing & Injection	9.91	33.0
300	Electrical & I&C	1.44	4.8
1500	Pulverizer Building & Site Work	0.80	2.7
A	Total Process Capital	12.2	40.5
B	General Facilities, 10% of A	1.2	4.1
C	Engineering & Home Office @ 10% of A	1.2	4.1
D	Project Contingency (15% of A+B+C)	2.2	7.3
E	Total Plant Cost	16.8	55.9
F	Allowance for Funds During Construction	0.0	0.0
G	Total Plant Investment	16.8	55.9
H	Royalty Allowance	0.0	0.0
I	Preproduction Costs (2 month startup)	0.13	0.4
J	Inventory Capital	0.0	0.0
K	Initial Catalyst & Chemicals	0.0	0.0
L	Subtotal Capital	16.9	56.3
M	Cost of Construction Downtime	0	0.0
N	Total Capital Requirement	16.9	56.3

Table 7.2-4

300 MWe CYCLONE BOILER OPERATING & MAINTENANCE COSTS

FIXED O&M COSTS	Units	Quantity	$/Unit	$MM/Yr
Operating Labor Maintenance Labor Maintenance Material Administration/Support Labor Subtotal Fixed Costs	Man-hr/yr	2190	23	$0.05 $0.19 $0.28 $0.14 $0.65
VARIABLE OPERATING COSTS				
Fuels Coal Increase (Due to increase in FA LOI)	Ton/yr	3251	30	0.10
Utilities Electric Power	kWh/yr	1,037,831	0.05	0.05
Subtotal Variable Cost				0.15
TOTAL O&M COST (FIXED+VARIABLE)				0.80

Table 7.2-5

300 MWe CYCLONE BOILER SUMMARY OF PERFORMANCE AND COST DATA

Power Plant Attributes	Units	Value
Plant Capacity, Net	MWe	300
Power Produced, Net	10^9 Kw-hr/yr	1.71
Plant Heat Rate, Net	Btu/kWh	9,500
Plant Life	yr	15
Capacity Factor	%	65
Coal Feed	10^6 Ton/yr	0.629
Reburn Coal as % of Total Coal Feed	%	20

Emissions Control Data	Units	NOx
Removal Efficiency	%	50
Emission Standard	lb/MM Btu	0.15
Emissions Without Controls	lb/MM Btu	1.25
Emissions With Controls	lb/MM Btu	0.63
Amount NOx Removed	Tons/Yr	5,071

	Current Dollars		Constant Dollars	
Levelized Cost of Power	Factor	Mills/kWh	Factor	Mills/kWh
Capital Charge	0.16	1.58	0.124	1.23
Fixed O&M Cost	1.314	0.50	1.00	0.38
Variable Operating Cost	1.314	0.11	1.00	0.09
Total Cost		2.19		1.70
Levelized Cost - NOx Basis	Factor	$/Ton Removed	Factor	$/Ton Removed
Capital Charge	0.16	533.3	0.124	413.3
Fixed O&M Cost	1.314	169.0	1.00	128.6
Variable Operating Cost	1.314	38.71	1.00	29.46
Total Cost		741		571

Table 8.1–1
Comparison of Costs of NOx Reduction Technologies

Boiler Type	**T-fired**
Plant Capacity, MWe	**300**
Plant Capacity Factor (%)	**65**
Remaining Plant Life (Yr.)	**15**
Initial NOx Level (lb/MM Btu)	**0.4**
Cost Basis:	**Constant Dollar**

NOx Reduction Technology	**Gas Reburn**	**MCR**	**SNCR**	**SCR**
% NOx Reduction	**50**	**25**	**25**	**80**
Capital Cost - $/kW	**15[a]**	**14**	**15[b]**	**59[c]**
Levelized Cost - $/ton of NOx Removed	**2,805[d]**	**1,008**	**1,506[b]**	**2060[c]**

[a] **Fulson, R. A.; Tyson, T. J. "Advanced Reburning for SIP Call NOx" presented at the EPRI-DOE-EPA Combined Utility Air Pollution Control Symposium, August 1998.**

[b] **Interpolated from "Electric Power Generation Cost Analysis for Compliance with EPA's Final Rule - Regional NOx Emission Reduction for 2003" October 1998, prepared by Burns and Roe for U.S. DOE Contract No. DE-AC22-94PC922100 Subtask 49.01, Table IX.**

[c] **Ibid., Table VII.**

[d] **Calculated by CONSOL Inc.**

Table 8.1–2
Comparison of Costs of NOx Reduction Technologies

Boiler Type	Cyclone
Plant Capacity, MWe	300
Plant Capacity Factor (%)	65
Remaining Plant Life (Yrs)	15
Initial NOx Level (lb/MM Btu)	1.25
Cost Basis:	Constant Dollar

NOx Reduction Technology	Gas Reburn	MCR	SNCR	SCR
% NOx Reduction	60	50	25	80
Capital Cost - $/kW	15[a]	56	15[b]	73[c]
Levelized Cost - $/ton of NOx Removed	748	571	1,506[b]	984[c]

[a] Fulson, R. A.; Tyson, T. J. "Advanced Reburning for SIP Call NOx" presented at the EPRI-DOE-EPA Combined Utility Air Pollution Control Symposium, August 1998.

[b] Interpolated from "Electric Power Generation Cost Analysis for Compliance with EPA's Final Rule - Regional NOx Emission Reduction for 2003" October 1998, prepared by Burns and Roe for U.S. DOE Contract No. DE-AC22-94PC922100 Subtask 49.01, Table IX.

[c] Staudt, J. E. "NESCAUM's Status Reports on NOx: Post-RACT Control Technologies and Cost Effectiveness" presented at the DOE 1998 Conference on Selective Catalytic and Non-Catalytic Reduction for NOx Control, Pittsburgh, PA, May 1998.

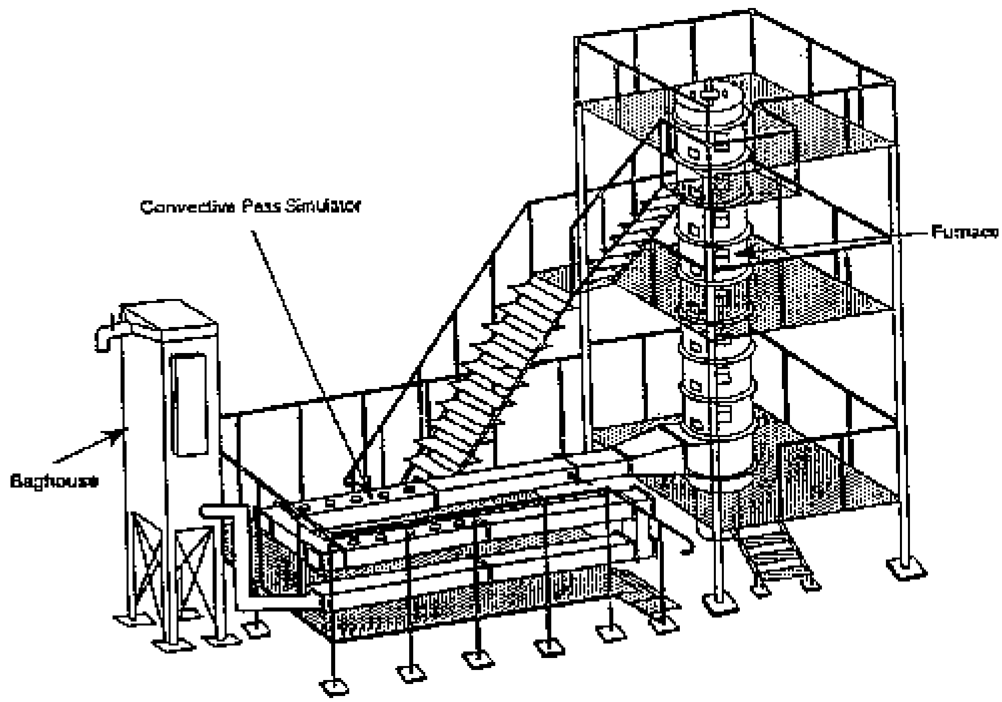


Figure 1.2.1.3-1 Schematic of pilot-scale test facility at EER Test Site, El Toro, CA.

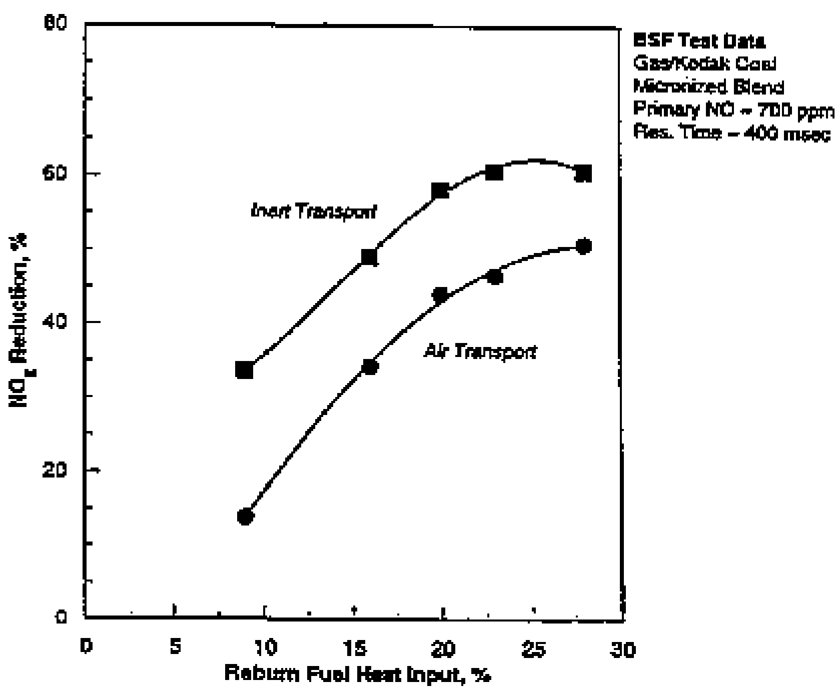


Figure 1.2.1.3-2 NOx control performance achieved with Kodak coal using air or simulated FGR for transport.

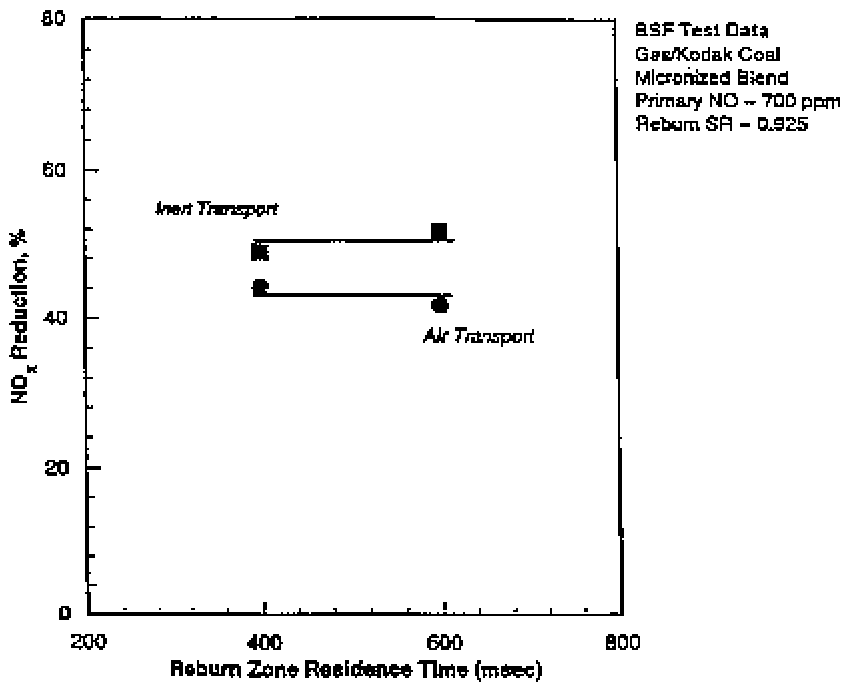


Figure 1 2.1.3-3 Impact of increasing residence time on coal reburn performance in EER Test Facility.

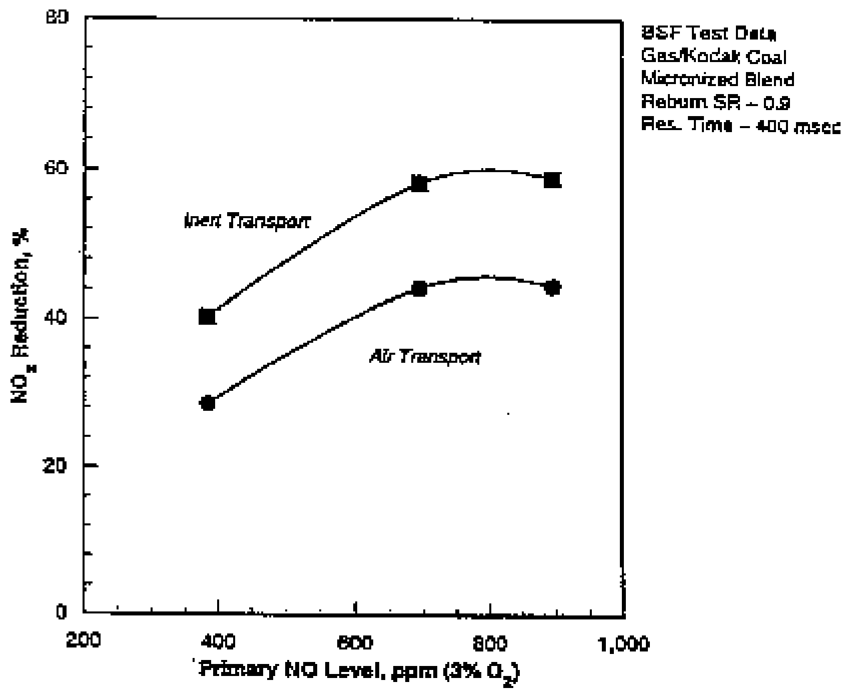


Figure 1.2.1.3-4 Impact of primary NOx level on coal reburn performance in EER Test Facility.

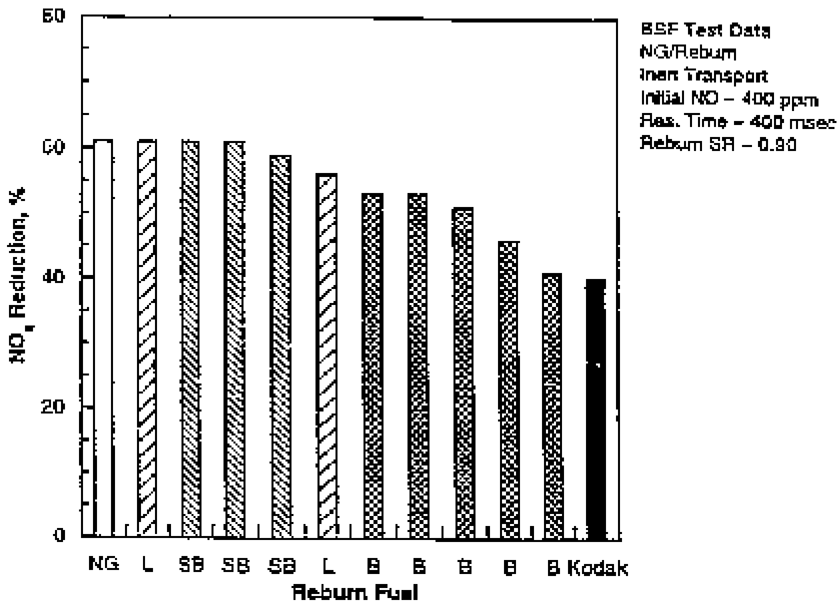


Figure 1.2.1.3-5 Comparison of NOx control performance of Kodak coal to other coals and natural gas. (NG=natural gas, L=lignite, SB=subbituminous coal, B=bituminous).

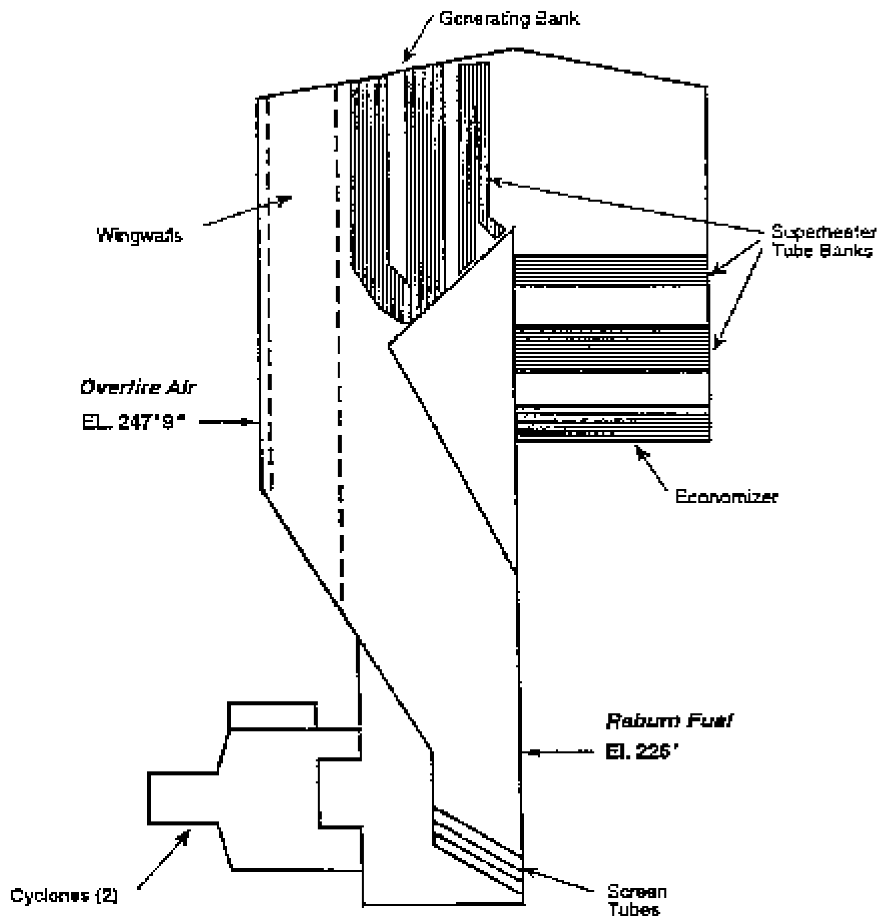


Figure 1.2.1.4-1 Reburn fuel and overfire air injection elevations for Kodak Boiler No. 15

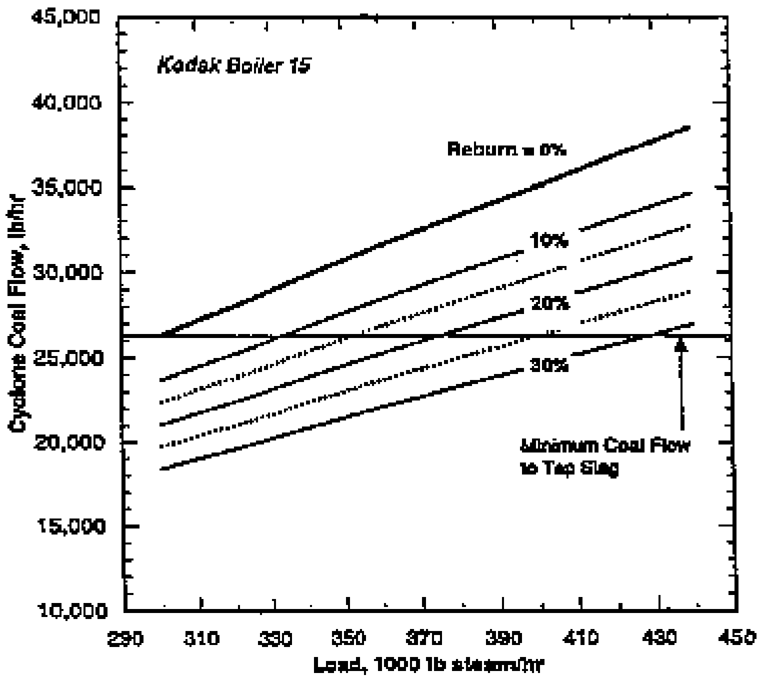


Figure 1.2.1.4-2 Cyclone coal flow rate versus load and reburn system operation.

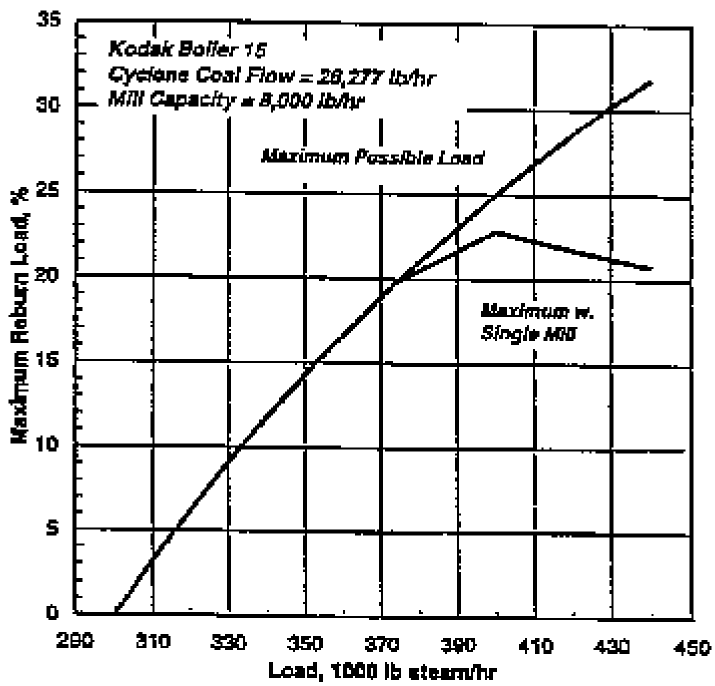


Figure 1.2.1.4-3 Maximum level of reburn system operation achievable while maintaining minimum coal flow to cyclones.

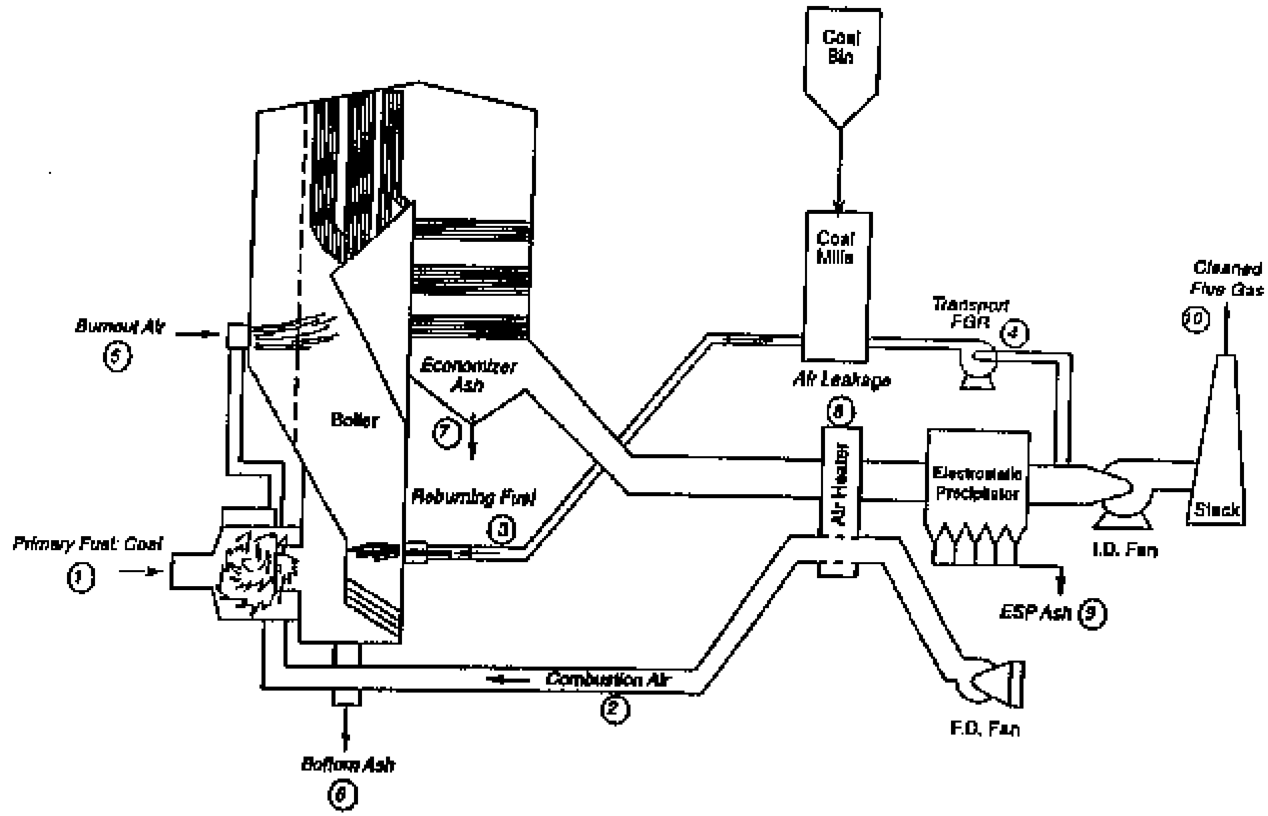


Figure 1.2.1.4-4 Coal reburning process flow diagram for Kodak Unit 15.

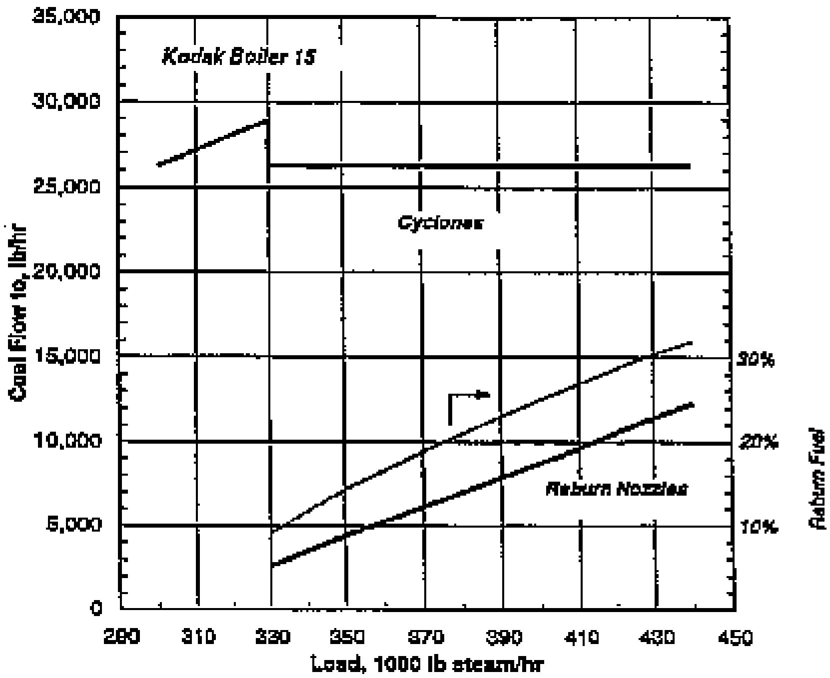


Figure 1.2.1.4-5 Coal flow rate to cyclones and reburn fuel nozzles over load range, for maximum NOx control.

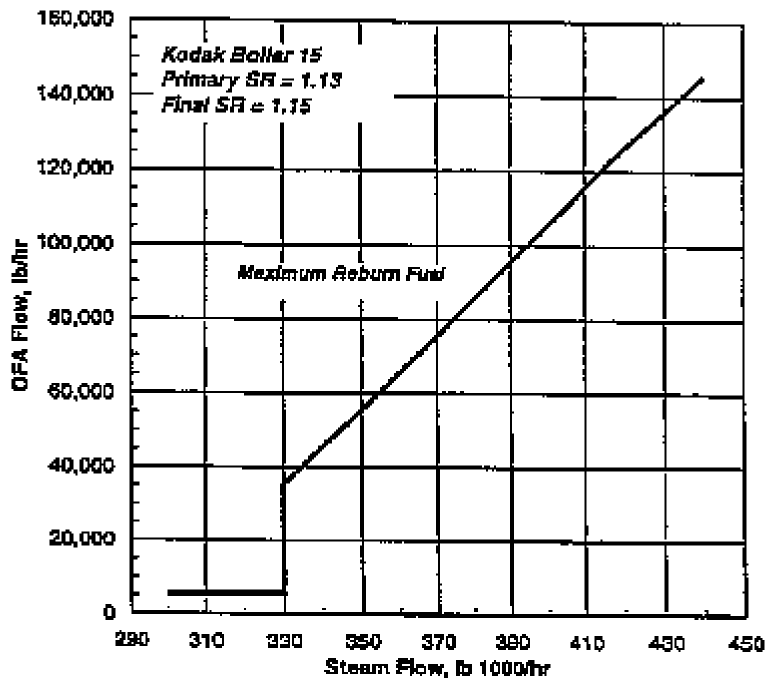


Figure 1.2.1.4-6 Overfire air flow rate to maintain fifteen percent excess air versus load.

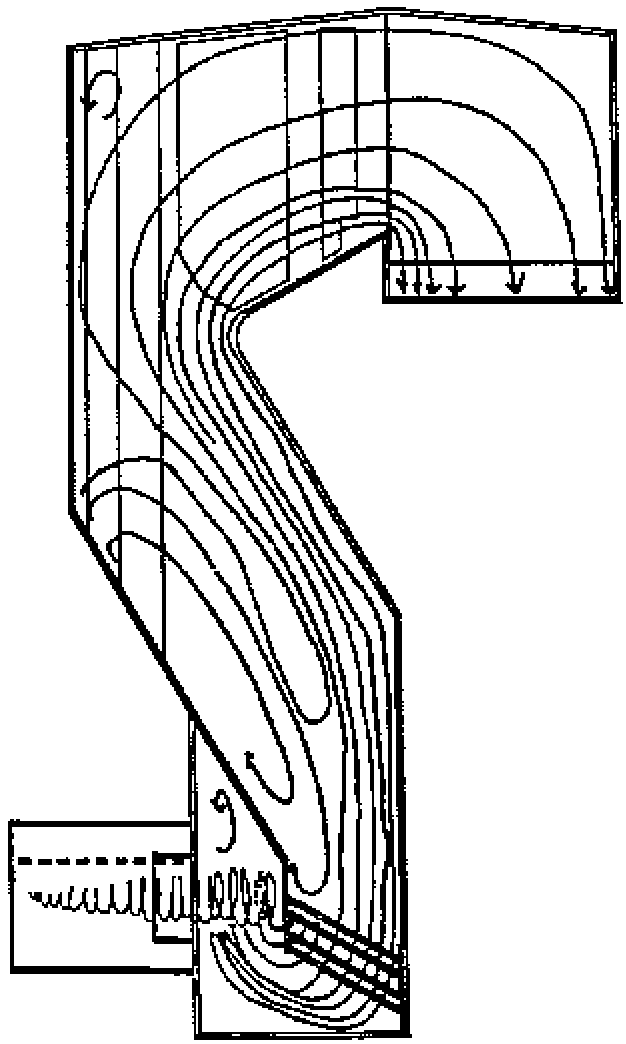
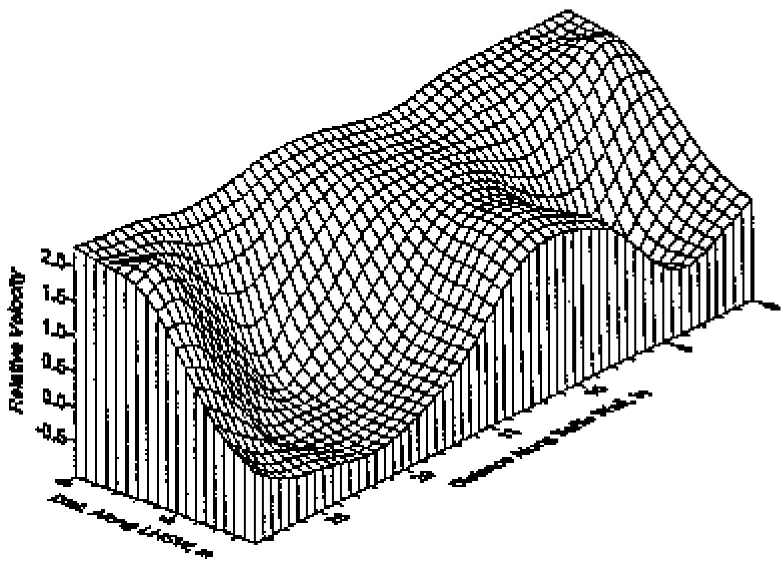
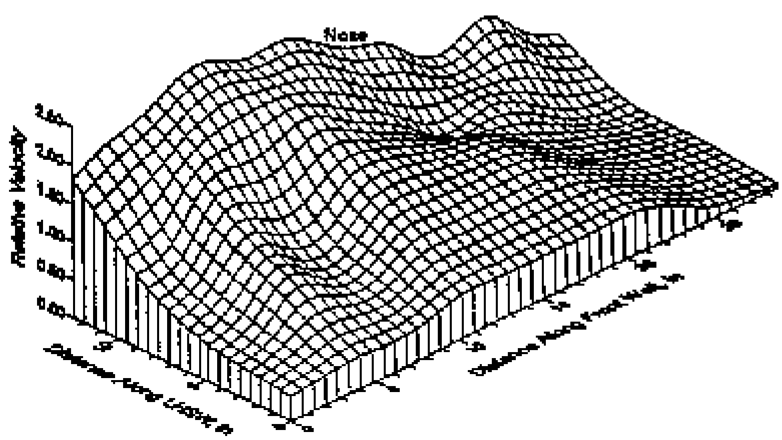


Figure 1.2.1.4-7 Sketch of general flow field features observed in isothermal flow model of Boiler No. 15.



(a). Velocity profiles at reburning fuel injection elevation (226').



(b). Velocity profiles at nose elevation.

Figure 1.2.1.4-8 Velocity profiles measured in isothermal flow model.

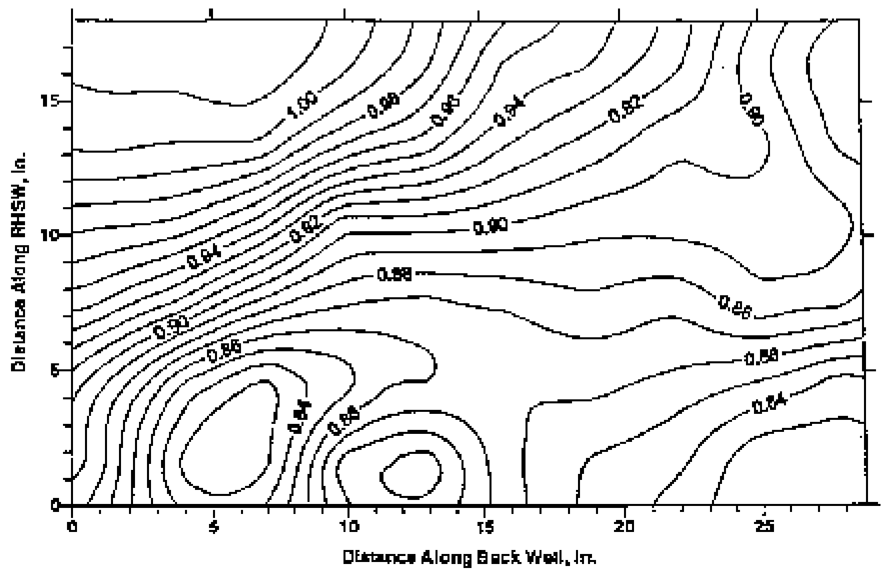


Figure 1.2.1.4-9 Reburn fuel dispersion for design case at 200 ms.
Reburn zone stoichiometry normalized to 0.90.

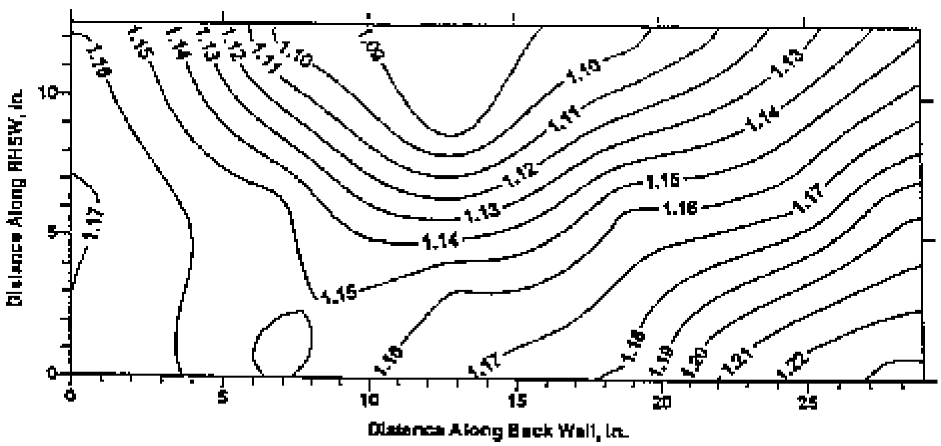


Figure 1.2.1.4-10 Overfire air dispersion for design case at 260 ms.
Final zone stoichiometry normalized to 1.15.

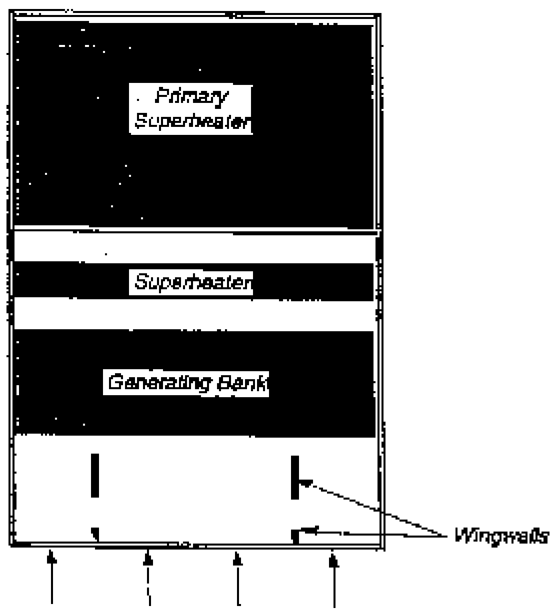


Figure 1.2.1.4-11 Layout of overfire air ports.

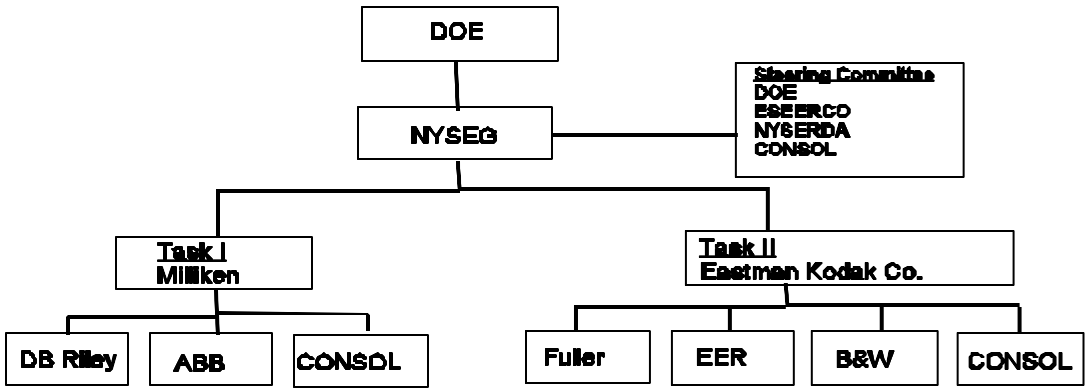


Figure1.2.2-1ProjectOrganization

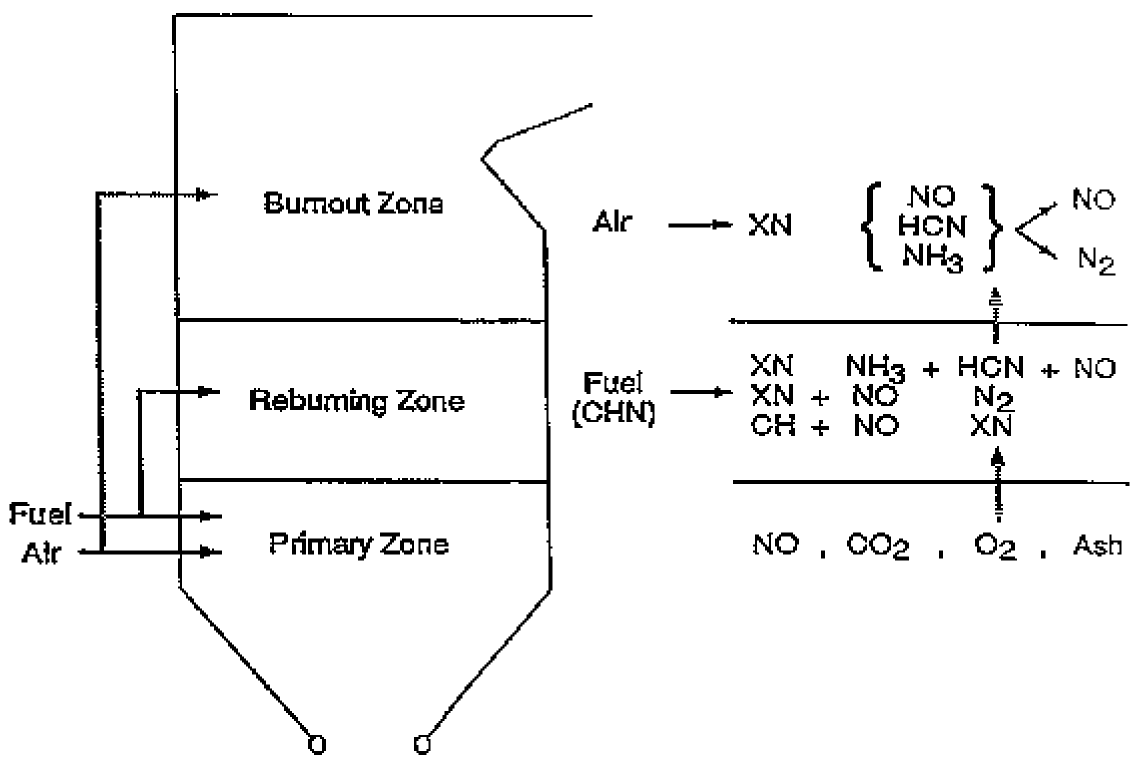


Figure 1.2.3-1 Schematic of the Reburning Process

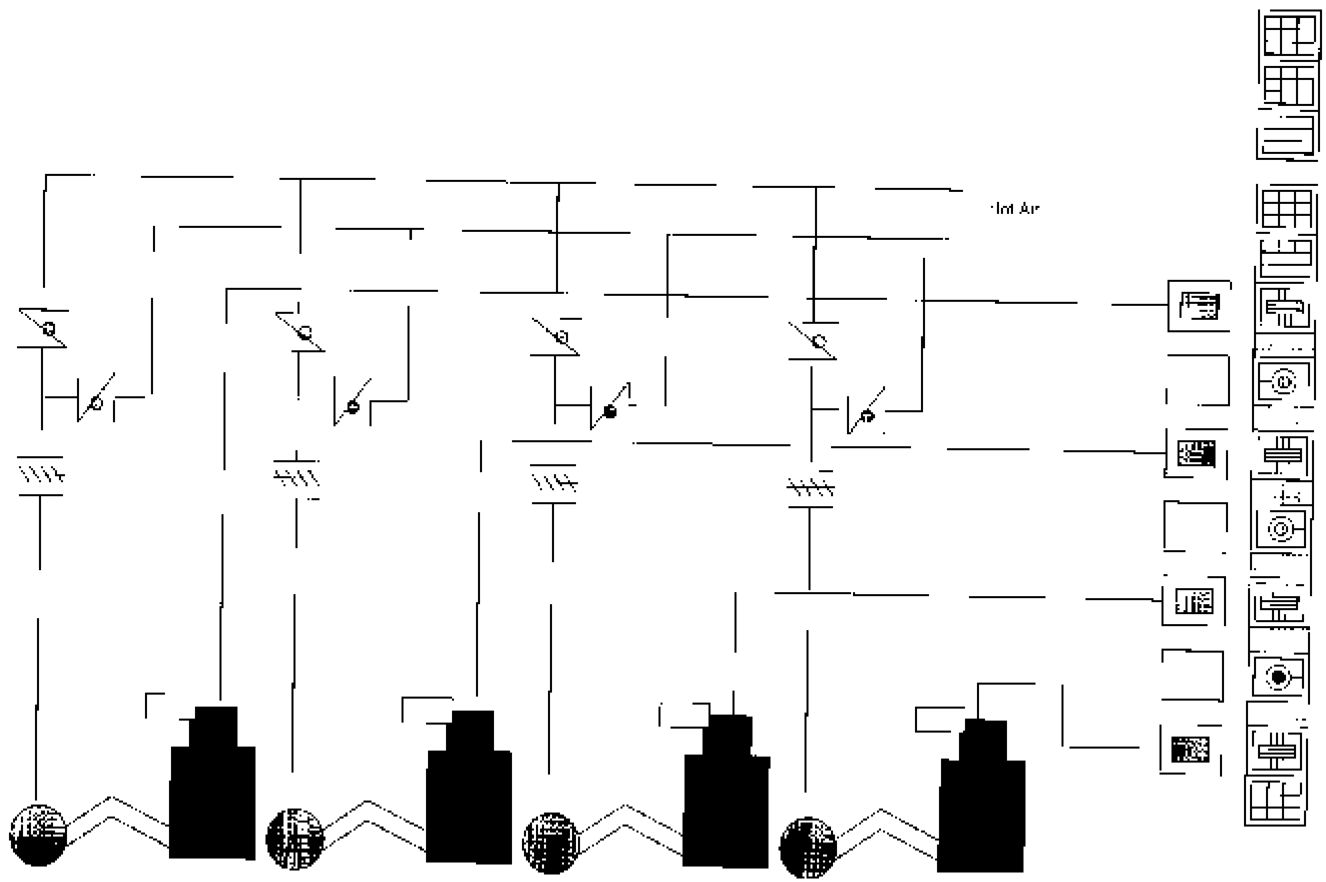


Figure 1.2.3-2 Milliken Station Simplified Fuel System Overview

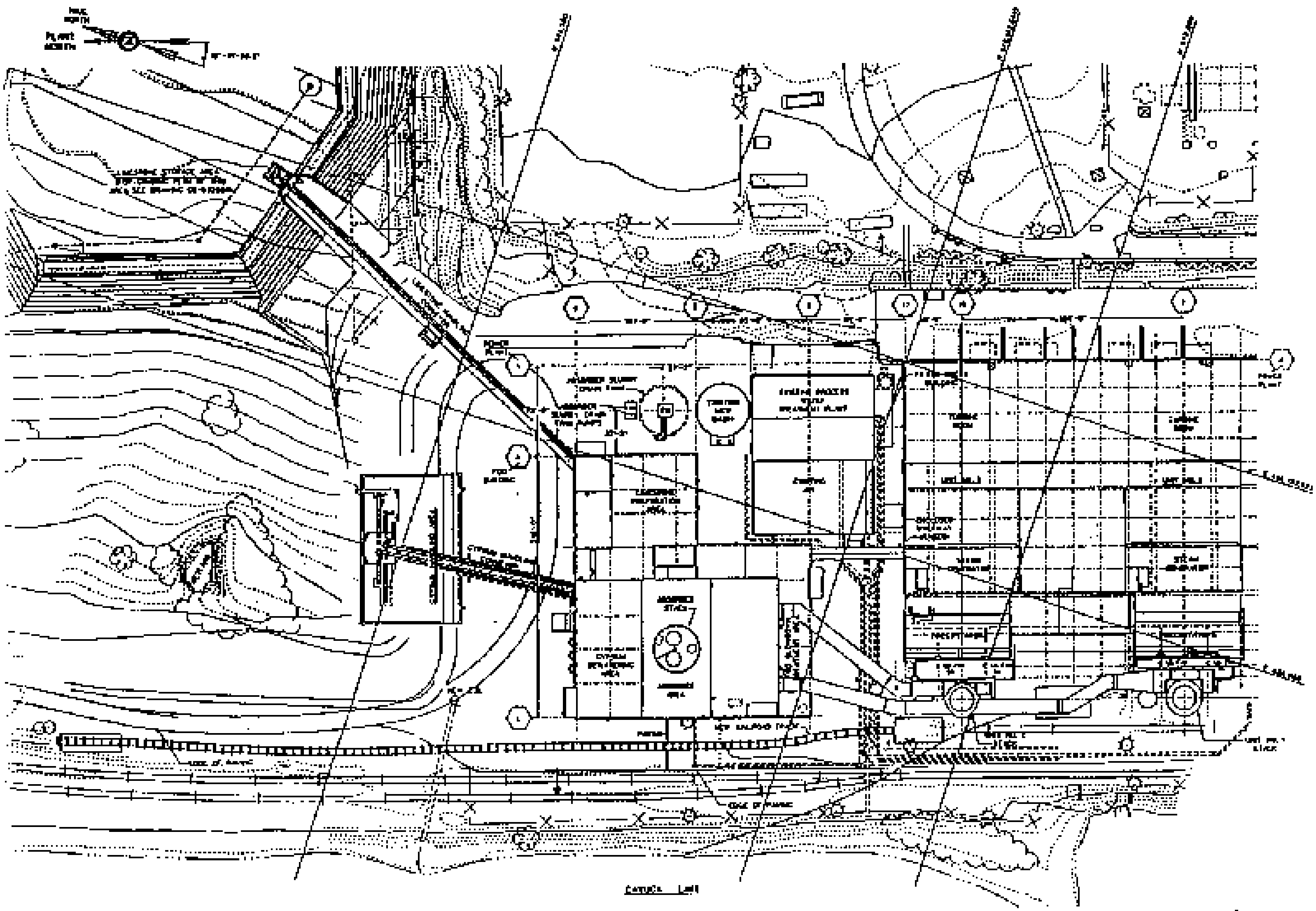


Figure 1.2.4.1-1 Milliken Station Site Plan

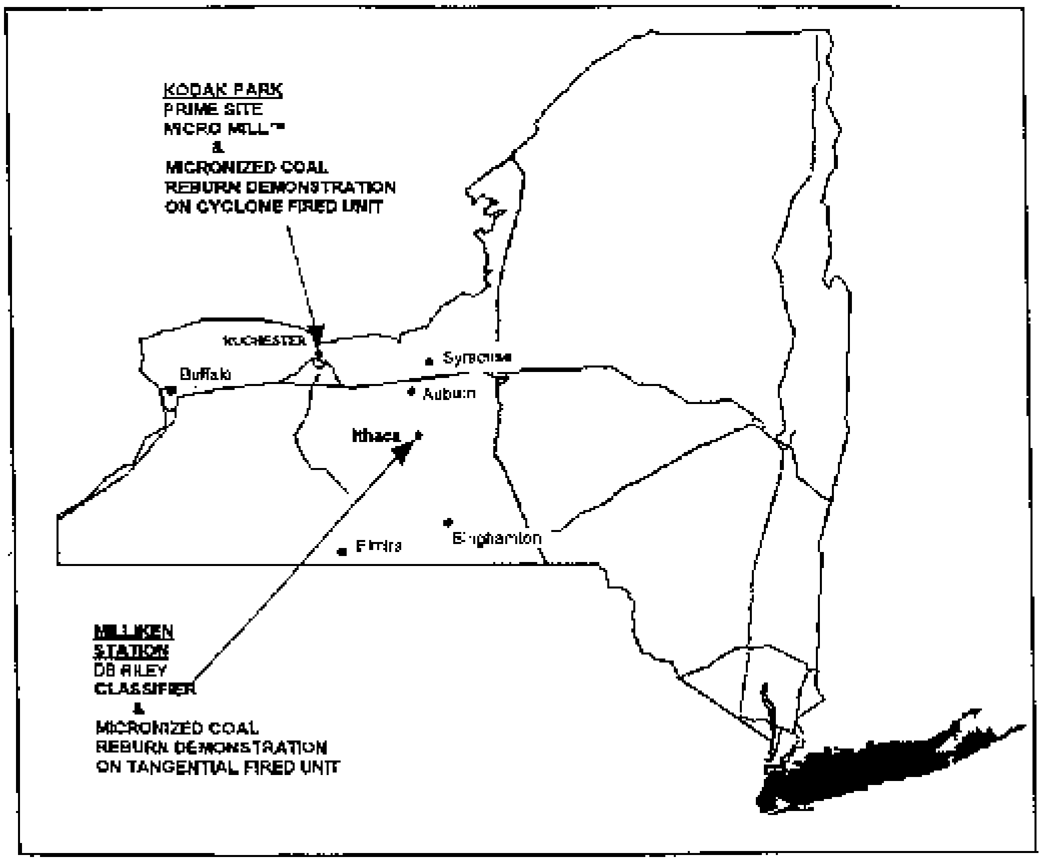


Figure 1.2.4.1-2 State Map of Site Locations

Figure 1.2.5-1 Project Milestone Schedule

Kodak Micronized Coal Project

Activity ID	Activity Description	Early Start	Actual Start	Early Finish	Actual Finish	Rem Dur	Percent complete
Gen. Tech. Srvces. - Project Management Group							
Project Managment / Administration							
KM95000129	Micro Coal Reburn (Kodak) Supervsn, Proj Mngmnt	01DEC95A	04DEC95	30JUN99		53	97
Proj. Mnagmnt-Cost Cntrl, Schdle, Admin							
KM95000130	Supprt Proj Budgt Managemnt-Micro C (KDK)	08JUL96A	08JUL96	30JUN99		53	95
KM95000149	Compile Schedule Updates - Micro Coal (Kodak)	07OCT96A	07OCT96	30JUN99		54	97
KM95000155	Enforce Project Closeouts - Micro Coal (Kodak)	01DEC98A	01DEC98	30JUN99		53	95
Cnsltnt/Outsde Engineering Firm - Dsgn & Eng Work							
KM95000152	Interface with CONSOL - Micro Coal (Kodak)	03FEB97A	03FEB97	30JUN99		53	98
Prep & Issue CoFndrs Topical Reports							
[illegible]	Draft Final Report - Micr Cl Kdk Project	04JAN99A	04JAN99	14MAY99		[illegible]	80
[illegible]	Distribute Micr Cl Kdk Final Report for Review	17MAY99		28MAY99		10	0
[illegible]	Incorporate comments Micr Cl Kdk Final Report	31MAY99		11JUN99		10	0
[illegible]	Incorporate Comments Micr Cl Kdk "Start-up" Rept	07JUN99		18JUN99		10	0
[illegible]	Route Micr Cl Kdk Final (Conformed) Rep for Rvw	14JUN99		25JUN99		10	0
[illegible]	Issue Micr Cl Kdk "Start-up" Report	21JUN99		25JUN99		5	0
[illegible]	Issue Micr Cl Kdk Final Report			25JUN99		0	0
CONSOL							
Cnsltnt/Outsde Engineering Firm - Dsgn & Eng Work							
[illegible]	Phase 3-CONSOL Responsibility-Micro Coal at	15SEP97A	15SEP97	30JUN99		53	95

MAR APR MAY 1999 JUN JUL

New York State Electric & Gas
Kodak Micronized Coal Project
Schedule Update Report

Activity ID	Activity Description	Early Start	Actual Start	Early Finish	Actual Finish	Rem Dur	Percent Complete	1999 MAR	APR	MAY	JUN	JUL
Kodak Responsibility												
Project Managment / Administration												
KM53X0141	Phse 3 (MCK) - Project Management	04MAR96A	04MAR96	30JUN99		53	95					▽ Phse 3 (

Project Start | Project Finish | Data Date | Run Date

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Early Bar | Progress Bar | Critical Activity

New York State Electric & Gas
Kodak Micronized Coal Project
Schedule Update Report

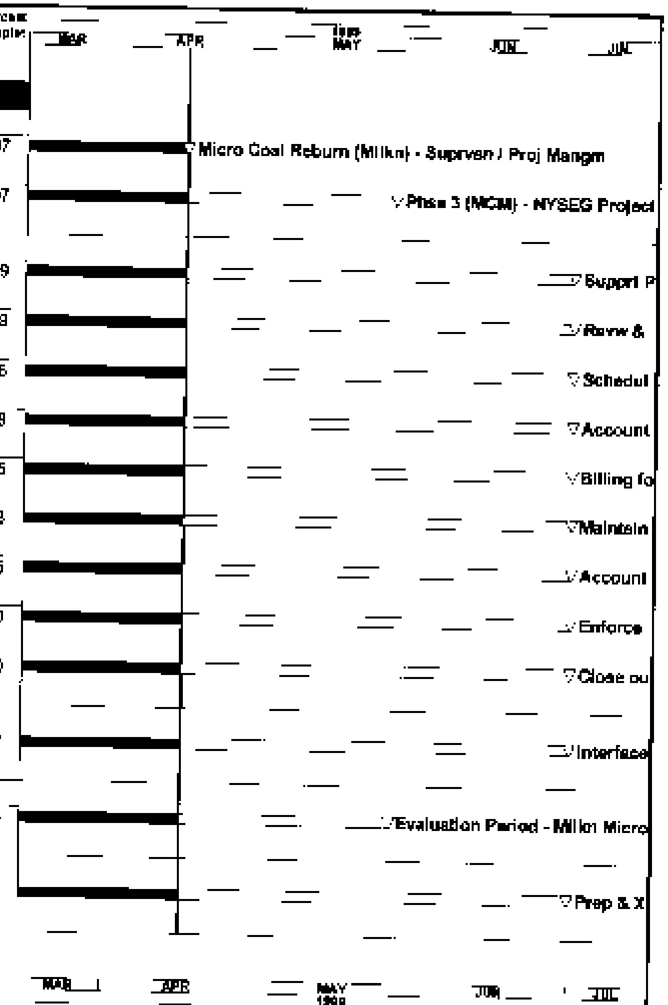
Sheet 2 of 4

Date	Revision	Checked	Approved

Milliken - Micronized Coal Project

Gen. Tech. Srvces. - Project Management Group

Activity ID	Activity Description	Early Start	Actual Start	Early Finish	Actual Finish	Rem Dur	Percent Complete
Project Managment / Administration							
MS96007032	Micro Coal Reburn (Milkn) - Suprvsn / Proj Mangm	04AUG97A	04AUG97	15APR99		0*	97
MS96007097	Phse 3 (MCM) - NYSEG Project Management Support	01SEP98A	01SEP98	26MAY99		29	97
Proj. Mnagmnt-Cost Cntrl, Schdle, Admin							
MS96007045	Supprt Proj Budgt Managemnt-Micro Cl (Milkn)	05AUG96A	05AUG96	30JUN99		53	99
MS96007050	Revw & Prcess P.O.'s & Reqs - Micro C. (Mil)	18NOV96A	18NOV96	30JUN99		53	99
MS96007037	Schedule Updates - Micro Coal (Milkn)	02JAN97A	02JAN97	30JUN99		54	95
MS96007036	Accounts Payable Invoicing - Micro Coal (Milkn)	07JUL97A	07JUL97	30JUN99		53	98
MS96007067	Billing for DOE, Tracking Sheet(Micro Coal, Mi)	25AUG97A	25AUG97	30JUN99		53	95
MS96007081	Maintain all Electronic Data - Micro Coal, Milkn	15FEB98A	15FEB98	30JUN99		53	98
MS96007044	Accounts Receivable - Micronized Coal (Milliken)	15MAY98A	15MAY98	30JUN99		53	65
MS96007063	Enforce Project Closeouts - Micro Coal (Milkn)	01DEC98A	01DEC98	30JUN99		53	90
MS96007046	Close out the Micronized Coal Project	04JAN99A	04JAN99	30JUN99		76	90
Cnsltnt/Outsde Engnrng Firm - Dsgn & Eng Work							
MS96007030	Interface with CONSOL - Micro Coal (Milkn)	02NOV98A	02NOV98	30JUN99		53	97
Post Start-up Testing & Evaluation							
MS96007062	Evaluation Period - Milkn Micro Cl	04JAN99A	04JAN99	26MAY99		29	98
Prep & Issue CoFndrs Topical Reports							
MS96007049	Prep & Xnsmit Cofndrs Topcl Reprts-Micr Cl (Mil)	17NOV97A	17NOV97	30JUN99		53	97



Project Start	29JUN96
Project Finish	13NOV02
Data Date	10APR99
Run Date	22APR99

Early Bar / Progress Bar / Critical Activity

New York State Electric & Gas
Kodak Micronized Coal Project
Schedule Update Report

Date | Revision | Checked | Approved

Activity ID	Activity Description	Early Start	Actual Start	Early Finish	Actual Finish	Rem Dur	Percent Complete	1999: MAR, APR, MAY, JUN, JUL
Prep & Issue CoFndrs Topical Reports								
MS0807042	Start-up Report - Micro Coal (Milkn)	04JAN99A	04JAN99	30JUN99		53	97	Start-up
CONSOL								
Cnsltnt/Outside Enginrng Firm - Dsgn & Eng Work								
MS0807002	Phse 3-CONSOL Responsibility-Mic Cl Mlkn	16OCT98A	16OCT98	28MAY99		28	0	Phse 3-CONSOL Responsibilit
Prep & Issue CoFndrs Topical Reports								
MS0807022	Write Cofndrs Topical Reprt(s)-Mlkn Micro Cl	04JAN98A	04JAN99	28MAY99		28	75	Write Cofndrs Topical Reprt(s)

MAR APR MAY 1999 JUN JUL

New York State Electric & Gas
Kodak Micronized Coal Project
Schedule Update Report

Early Bar
Progress Bar
Critical Activity

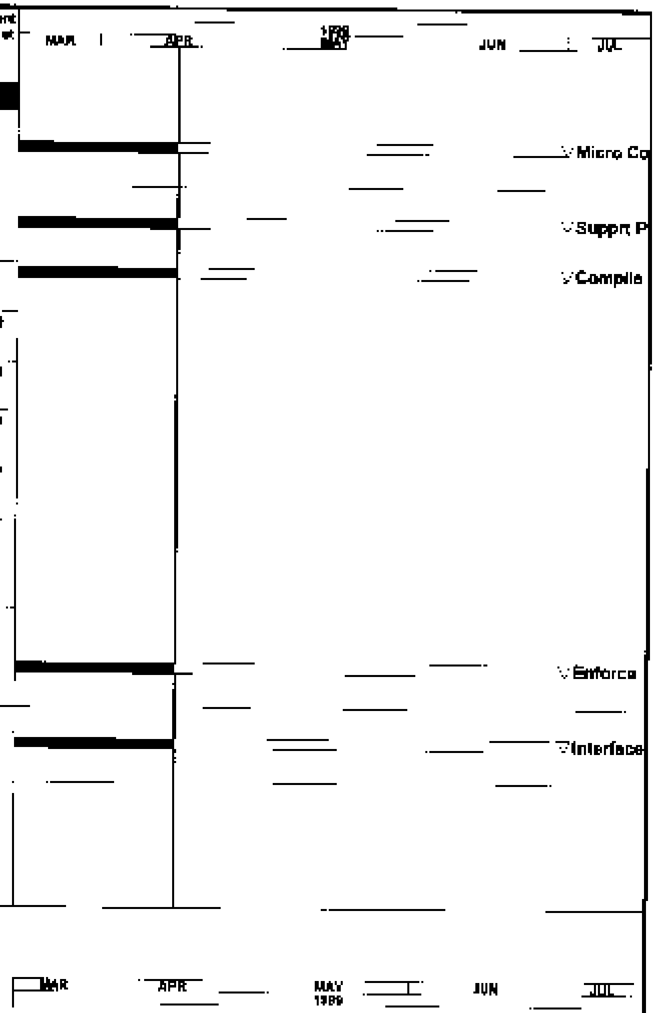
Date
Revision
Approved

Activity ID	Activity Description	Early Start	Actual Start	Early Finish	Actual Finish	Rem Dur	Percent complete

Kodak Micronized Coal Project

Gen. Tech. Srvces. - Project Management Group

Activity ID	Activity Description	Early Start	Actual Start	Early Finish	Actual Finish	Rem Dur	Percent complete
Project Managment / Administration							
KM85000139	Micro Coal Reburn (Kodak) - Suprvsn, Proj Mngmnt	04DEC95A	04DEC95	30JUN99		53	97
Proj. Mnagmnt-Cost Cntrl, Schdle, Admin							
[illegible]	Suppt Proj Budgt Managemnt-Micro Cl (KDK)	08JUL96A	08JUL96	30JUN99		53	95
KM85000145	Compile Schedule Updates - Micro Coal (Kodak)	07OCT96A	07OCT96	30JUN99		54	97
KM85000134	Prep & Issue Utld Cost Sheets to PLE-Mic Cl, KDK	02JAN97A	02JAN97	12FEB99A	12FEB99	0	100
KM85000163	Maintain all Electronic Data - Micro Coal, Kodak	03FEB97A	03FEB97	12FEB99A	12FEB99	0	100
KM85000147	Payroll Tracking - Micro Coal (Kodak)	24FEB97A	24FEB97	13NOV98A	13NOV98	0	100
KM85000155	Revw & Process P.O.'s & Reqs - Micro Cl (KDK)	10MAR97A	10MAR97	05MAR99A	05MAR99	0	100
[illegible]	Accounts Payable Invoicing - Micro Coal (Kodak)	05MAY97A	05MAY97	25SEP98A	25SEP98	0	100
KM85000160	Accounts Receivable - Micronized Coal (Kodak)	05MAY97A	05MAY97	09OCT98A	09OCT98	0	100
KM85000138	Billing for DOE Tracking Sheet(Micro Coal, KDK)	08SEP97A	08SEP97	31DEC98A	31DEC98	0	100
KM85000158	Enforce Project Closeouts - Micro Coal (Kodak)	01DEC98A	01DEC98	30JUN99		53	95
Cnsltnt/Outside Enginrng Firm - Dsgn & Eng Work							
KM85000152	Interface with CONSOL - Micro Coal (Kodak)	03FEB97A	03FEB97	30JUN99		53	98
Post Start-up Testing & Evaluation							
[illegible]	Conduct Testing Coordination - Micro Coal (Kodak)	03MAR97A	03MAR97	30OCT98A	30OCT98	0	100
KM85000164	Prepare Final Phase II Test Plan (MCK) - Draft	07JUL97A	07JUL97	26SEP97A	26SEP97	0	100



New York State Electric & Gas
Kodak Micronized Coal Project
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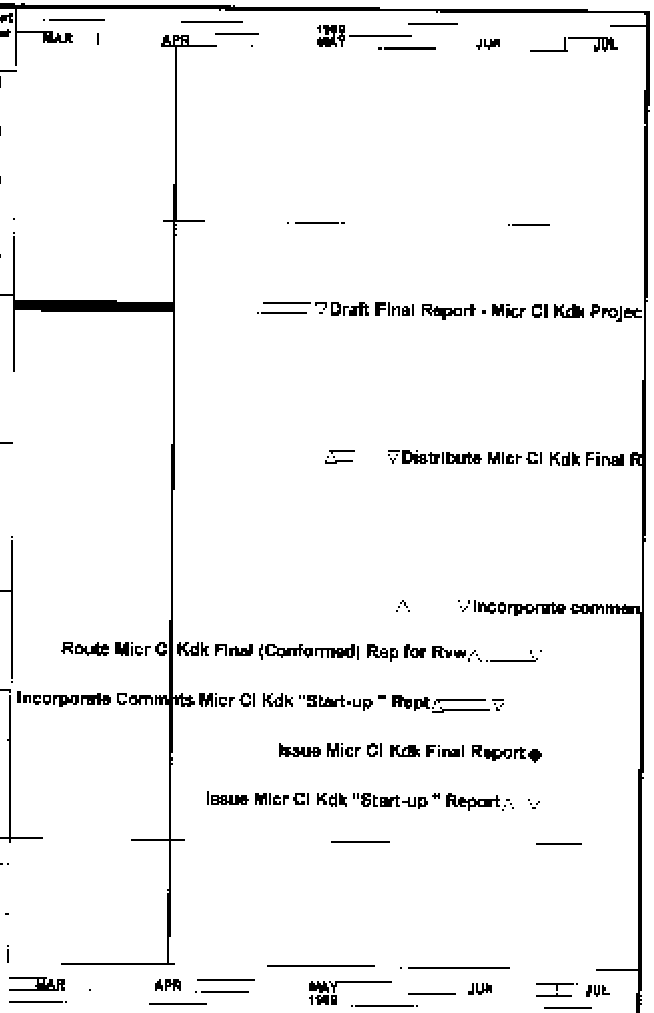
Activity ID	Activity Description	Early Start	Actual Start	Early Finish	Actual Finish	Rem Dur	Percent Complete
Reports / Studies on Operations & Testing Reslts							
KM96000140	Testing Data Collection - Micro Coal (Kodak)	27JAN97A	27JAN97	26FEB99A	26FEB99	0	100
KM96000137	Devlp Parameters, Testing Data Collctn - MC/Kdk	15JAN98A	15JAN98	17JUL98A	17JUL98	0	100
KM95000135	Start-up Report - Micro Coal (Kodak)	15APR98A	15APR98	15JAN99A	15JAN99	0	100
Prep & Issue CoFndrs Topical Reports							
KM960001A2	Draft Micro Coal (Kdk) "Start-up" Report	14SEP98A	14SEP98	12MAR99A	12MAR99	0	100
KM950001E0	Draft Final Report - Micr Cl Kdk Project	04JAN99A	04JAN99	14MAY99		2[illegible]	60
KM950001E7	Prep Critical Component Failure Micr Cl Kdk Rep	04JAN99A	04JAN99	12FEB99A	12FEB99	0	100
KM950001E8	Prep Reliability, Availability Rept Micr Cl Kdk	04JAN99A	04JAN99	12FEB99A	12FEB99	0	100
KM95000[illegible]	Distribute Micr Cl Kdk Final Report for Review	17MAY99		28MAY99		10	0
KM950001F4	Phse 3(MCK)-Issue Reprt Micro Coal Effctvness	01FEB99A	01FEB99	12MAR99A	12MAR99	0	100
KM960001B3	Route & Rvw Micro Coal (Kdk) "Start-up" Report	01FEB99A	01FEB99	12MAR99A	12MAR99	0	100
KM95000110	Incorporate comments Micr C Kdk Final Report	31MAY99		11JUN99		10	0
KM95000117	Route Micr Cl Kdk Final (Conformed) Rep for Rvw	14JUN99		25JUN99		10	0
KM950001E2	Incorporate Commnts Micr Cl Kdk "Start up" Rept	07JUN99		18JUN99		10	0
KM95000[illegible]	Issue Micr Cl Kdk Final Report			25JUN99		0	0
KM950001F1	Issue Micr Cl Kdk "Start-up" Report	21JUN99		25JUN99		5	0
Prep & Issue CoFndrs Qurtrly Environmntl Report							
KM950001G5	Prep & Xmit Mic Cl Envrnmntl Reprt Qrtr 1,1998	15JAN98A	15JAN98	27NOV98A	27NOV98	0	100
KM950001E0	Prep & Xmit Mic Cl Envrnmntl Reprt-Qrtr 1,1998	27APR98A	27APR98	31DEC98A	31DEC98	0	100



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New York State Electric & Gas
Kodak Micronized Coal Project
Schedule Update Report

Date | Revision | Checked | Approved

Activity ID	Activity Description	Early Start	Actual Start	Early Finish	Actual Finish	Rem Dur	Percent Complete
Prep & Issue CoFndrs Qurtrly Technical Reprt							
KM95000104	Prep & Iss Mic Cl Monthly Co-Fndrs Reprt (Kodak)	15JAN98A	15JAN98	04DEC98A	04DEC98	0	100
KM95000102	Prep & Iss Mic Cl Tchncl Progss Rprt-Qtr 2 1998	15JAN98A	15JAN98	11DEC98A	11DEC98	0	100
KM95000101	Prep & Iss Mic Cl Tchncl Progss Rprt-Qrtr 1,1998	15MAY98A	15MAY98	11DEC98A	11DEC98	0	100
KM950001F7	Prep & Iss Mic Cl Tchncl Progss Rprt-Qrtr 1,1997	15MAY98A	15MAY98	11DEC98A	11DEC98	0	100
CONSOL							
Cnsltnt/Outsde Enginrng Firm - Dsgn & Eng Work							
KM95000143	Phse 3-CONSOL Responsibility Micro Coal at	15SEP97A	15SEP97	30JUN99		53	35
Kodak Responsibility							
Project Definition or Origination							
KM95000101	Pre-Award (MCK)- Scope Definition	05SEP95A	05SEP95	06FEB95A	06FEB95	0	100
Preliminary / Conceptual Engineering							
KM95000109	Phse 1 (MCK) - Modeling	22JAN96A	22JAN96	16APR96A	16APR96	0	100
KM95000110	Phse 1 (MCK) - Boiler Additions	22JAN96A	22JAN96	01MAY96A	01MAY96	0	100
KM95000111	Phse 1 (MCK) - Injectors and OFA Ports	22JAN96A	22JAN96	15MAY96A	15MAY96	0	100
KM95000112	Phse 1 (MCK) - Electrostatic Precipitators	29JAN96A	29JAN96	15FEB96A	15FEB96	0	100
KM95000113	Phse 1 (MCK) - Westinghouse (WDPF)	12FEB96A	12FEB96	20MAR96A	20MAR96	0	100
KM95000114	Phse 1 (MCK) - Control Room	12FEB96A	12FEB96	02APR96A	02APR96	0	100
KM95000115	Phse 1 (MCK) - Building Additions	12FEB96A	12FEB96	03MAY96A	03MAY96	0	100
KM95000116	Phse 2 (MCK) - Control Room	12FEB96A	12FEB96	20DEC96A	20DEC96	0	100
KM95000117	Phse 1 (MCK) - Micronizers	04MAR96A	04MAR96	01MAY96A	01MAY96	0	100

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New York State Electric & Gas
Kodak Micronized Coal Project
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Activity ID	Activity Description	Early Start	Actual Start	Early Finish	Actual Finish	Rem Dur	Percent Complete
Project Managment / Administration							
KM95000104	Phase 1 (MCK) - Project Management	06NOV95A	06NOV95	01APR96A	01APR96	0	100
KM950001[illegible]6	Phase 2 (MCK) - Project Management	04MAR96A	04MAR96			0	100
KM95000141	Phase 3 (MCK) - Project Management	04MAR96A	04MAR96	30JUN99		53	95
Proj. Mnagmnt-Cost Cntrl, Schdle, Admin							
KM95000107	Pre-Award (MCK) - Planning	02JAN96A	02JAN96	15MAR96A	15MAR96	0	100
Prepare Initial / Budget Estimates							
KM95000102	Pre Award (MCK) - Financing	15SEP95A	15SEP95	12MAR96A	12MAR96	0	100
Perform Licensing / Acquire Permits							
KM95000102	Phase 1 (MCK) - Licenses and Permits	02OCT95A	02OCT95	29APR96A	29APR96	0	100
KM95000105	Pre-Award (MCK) - Agency Contacts	20NOV95A	20NOV95	17JAN96A	17JAN96	0	100
Award Contract for Consultant/Special Services							
KM95000108	Pre-Award (MCK) - Contracts	20NOV95A	20NOV95	08MAR96A	08MAR96	0	100
Construction Management Tasks							
KM95000118	Phase 2 (MCK) - Injectors and OFA Ports	11MAR96A	11MAR96	20JAN97A	20JAN97	0	100
KM95000120	Phase 2 (MCK) - Boiler Additions	26MAR96A	26MAR96	15JAN97A	15JAN97	0	100
KM95000121	Phase 2 (MCK) - Westinghouse (WDPF)	26MAR96A	26MAR96	15JAN97A	15JAN97	0	100
KM95000122	Phase 2 (MCK) - Arch. and Engineering	01APR96A	01APR96	28JUN96A	28JUN96	0	100
KM95000123	Phase 2 (MCK) - Micronizers	01APR96A	01APR96	20JAN97A	20JAN97	0	100
KM95000125	Phase 2 (MCK) - Instrument and Electrical	08APR96A	08APR96	20FEB97A	20FEB97	0	100
KM95000128	Phase 2 (MCK) - Building Additions	26APR96A	26APR96	10DEC96A	10DEC96	0	100

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Phase 3 (

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Project Start
Project Finish
Data Date
Run Date

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Kodak Micronized Coal Project
Schedule Update Report

Date Revision Checked Approved

Activity ID	Activity Description	Early Start	Actual Start	Early Finish	Actual Finish	Rem Dur	Percent Complete
Construction Management Tasks							
KM6500D126	Phse 2 (MCK) - Dismantlements	08MAY96A	08MAY96	02DEC96A	02DEC96	0	100
KM6500D133	Phse 2 (MCK) - General Construction	17JUN96A	17JUN96	13JAN97A	13JAN97	0	100
Start-Up / Checkout							
KM6500D152	Phse 3 (MCK) - Start up Micro Mill	03FEB97A	03FEB97	03FEB97A	03FEB97	0	100
System Ready for on-line operation							
KM6500D161	Phse 2 (MCK) - Boiler 15 On-Line			15JAN97A	15JAN97	0	100
Post Start-up Equipment Tuning, Mods, Repairs							
KM6500D163	Phse 3 (MCK) - Tune Micro Mill	15APR97A	15APR97	15APR97A	15APR97	0	100
KM6500D164	Phse 3 (MCK) - Tune Reburn Syst(Parametric Test)	21APR97A	21APR97	11MAY97A	11MAY97	0	100
KM6500D175	Phse 3 - Sept 97 Maintenance Outage	08SEP97A	08SEP97	26SEP97A	26SEP97	0	100
KM6500D176	Phse 3 (MCK) - EER perform Fine Tuning Adjust	06OCT97A	06OCT97	17OCT97A	17OCT97	0	100
KM6500D1A3	Phse 3 - Design Port Layout, Assmbly Tst Plr	12JAN98A	12JAN98	02FEB98A	02FEB98	0	100
KM6500D1A5	Phse 3 - Develop first Scope for O2 Upgrade	12JAN98A	12JAN98	02FEB98A	02FEB98	0	100
KM6500D1A4	Phse 3 - Fab Ports and Probes for O2	19JAN98A	19JAN98	10MAR98A	10MAR98	0	100
KM6500D184	Phse 3 (MCK) - Fix Mechanical & Control Problems	19JAN98A	19JAN98			0	100
KM6500D185	Phse 3 - Boiler 15 Spring Shutdown / Overhaul	30JAN98A	30JAN98	10MAR98A	10MAR98	0	100
KM6500D1A7	Phse 3 - Install Access Ports	03FEB98A	03FEB98	10MAR98A	10MAR98	0	100
KM6500D1A8	Phse 3 - Aim and Calibrate Scanners	11MAR98A	11MAR98	11MAR98A	11MAR98	0	100
KM6500D1A9	Phse 3 - 15 Boiler Start-up	11MAR98A	11MAR98	11MAR98A	11MAR98	0	100

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Project Start 03JAN96
Project Finish 11SEP02
Data Date 1APR99
Run Date 22APR99

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New York State Electric & Gas
Kodak Micronized Coal Project
Schedule Update Report

Date | Revision | Checked | Approved

Activity ID	Activity Description	Early Start	Actual Start	Early Finish	Actual Finish	Rem Dur	Percent Complete
Post Start-up Equipment Tuning, Mods, Repairs							
KM95000157	Phse 3 - Complete Air Flow Calculations	23MAR98A	23MAR98	03APR98A	03APR98	0	100
KM95000181	Phse 3 - Perform Gas Calibrations to the Injectr	06APR98A	06APR98	24APR98A	24APR98	0	100
[illegible]	Phse 3 - Write Air Flow Test Report	06APR98A	06APR98	30NOV98A	30NOV98	0	100
[illegible]	Phse 3 - Rpr OFA Drvs/Actuatrs Add Thermocples	10APR98A	10APR98	11APR98A	11APR98	0	100
[illegible]	Phse 3 - Install Yokagowa Probes & Verify	10APR98A	10APR98	05JUN98A	05JUN98	0	100
KM95000125	Phse 3 - Install Temporary Probes	11APR98A	11APR98			0	100
[illegible]	Phse 3 - Produce Base line Curves (O2, NOx, CO)	15APR98A	15APR98	01MAY98A	01MAY98	0	100
[illegible]	Phse 3 - Produce NOx Curves with Reburn	15APR98A	15APR98	05JUN98A	05JUN98	0	100
KM95000106	Phse 3 - Parametric Test	01MAY98A	01MAY98	29MAY98A	29MAY98	0	100
[illegible]	Phse 3 - Write Gas Testing Report	11MAY98A	11MAY98	30NOV98A	30NOV98	0	100
[illegible]	Phse 3 - Perform O2 Meter & Auto Curves Test	27MAY98A	27MAY98	05JUN98A	05JUN98	0	100
[illegible]	Phse 3 - modify O2 controls	29MAY98A	29MAY98	05JUN98A	05JUN98	0	100
Post Start-up Testing & Evaluation							
[illegible]	Phse 3(MCK) - Track Operation and Maintenance	03FEB97A	03FEB97	12FEB99A	12FEB99	0	100
[illegible]	Phse 3(MCK) - Rata Test on CEM System	10MAR97A	10MAR97	11MAR97A	11MAR97	0	100
[illegible]	Phse 3(MCK) - Factory Mutua Test	21NOV97A	21NOV97	24NOV97A	24NOV97	0	100
[illegible]	Phse 3(MCK) - Cofunders Contribution	02DEC97A	02DEC97	30JAN98A	30JAN98	0	100
[illegible]	Phse 3(MCK) - Project Commissioning	01JAN98A	01JAN98	30NOV98A	30NOV98	0	100

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New York State Electric & Gas
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Schedule Update Report

Activity ID	Activity Description	Early Start	Actual Start	Early Finish	Actual Finish	Rem Dur	Percent Complete
Post Start-up Testing & Evaluation							
KM95000164	Phse 3(MCK) - Obtain Parmetric Test Data	06APR98A	06APR98	30APR98A	30APR98	0	100
KM95000167	Phse 3(MCK) - Kodak analyzes all curves	06APR98A	06APR98	05JUN98A	05JUN98	0	100
KM95000165	Phse 3(MCK)- CONSOL coordinates Tsting w/ Kodak	06APR98A	06APR98			0	100
KM95000152	Phse 3(MCK) - CONSOL finalize/issues Test Plan	27APR98A	27APR98	05JUN98A	05JUN98	0	100
KM95000168	Phse 3(MCK) - Develop Control Curves	04MAY98A	04MAY98	29MAY98A	29MAY98	0	100
KM95000169	Phse 3(MCK) - Demo Max Cont. Ratg	15MAY98A	15MAY98	29MAY98A	29MAY98	0	100
KM95000171	Phse 3MCK) - Determine Max Cont. O. L. Ratg	15MAY98A	15MAY98	29MAY98A	29MAY98	0	100
KM95000162	Phse 3(MCK) - Demo NOx Reduction	15MAY98A	15MAY98	07AUG98A	07AUG98	0	100
KM95000166	Phse 3(MCK) - Kodak Loads Cntl curves into WDPF	29MAY98A	29MAY98	12JUN98A	12JUN98	0	100
KM95000164	Phse 3(MCK) - CONSOL Set-up for Testing	02JUN98A	02JUN98	04JUN98A	04JUN98	0	100
KM95000172	Phse 3(MCK) - Prove Micronizers and Injectors	02JUN98A	02JUN98	07AUG98A	07AUG98	0	100
KM95000178	Phse 3(MCK) - CONSOL Conducts 5-day Baseline Tst	03JUN98A	03JUN98	05JUN98A	05JUN98	0	100
KM95000177	Phse 3(MCK) - Perform UARG 51 Day Test	08JUN98A	08JUN98	07AUG98A	07AUG98	0	100
KM95000173	Phse 3(MCK) - Long Term Operation	07AUG98A	07AUG98	29JAN99A	29JAN99	0	100
KM95000176	Phse 3(MCK) - CONSOL Perform 4-day Validatn Tst	21SEP98A	21SEP98	30SEP98A	30SEP98	0	100
Prep & Issue CoFndrs Topical Reports							
KM95000163	Phse 3(MCK)-prep fnl reprt Parametric Test	20APR98A	20APR98	30MAY98A	30MAY98	0	100
KM95000170	Phse 3(MCK)-Draft Rep. Micro Coal Effectiveness	04JAN99A	04JAN99	12FEB99A	12FEB99	0	100

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New York State Electric & Gas
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Activity ID	Activity Description	Early Start	Actual Start	Early Finish	Actual Finish	Rem Dur	Percent complete	1999 MAR – JUL
Prep & Issue CoFndrs Topical Reports								
KM95C03160	Phse 3(MCK)-Route Drft Rep Micro Cl Effctivness	15FEB99A	15FEB99	16FEB99A	16FEB99	0	100	
KM95C03161	Phse 3(MCK)-Incorprate Commnts Micro Coal Rep	01MAR99A	01MAR99	02APR99A	02APR99	0	100	Phse 3(MCK)-Incorprate Commnts Micro Coal Rep.

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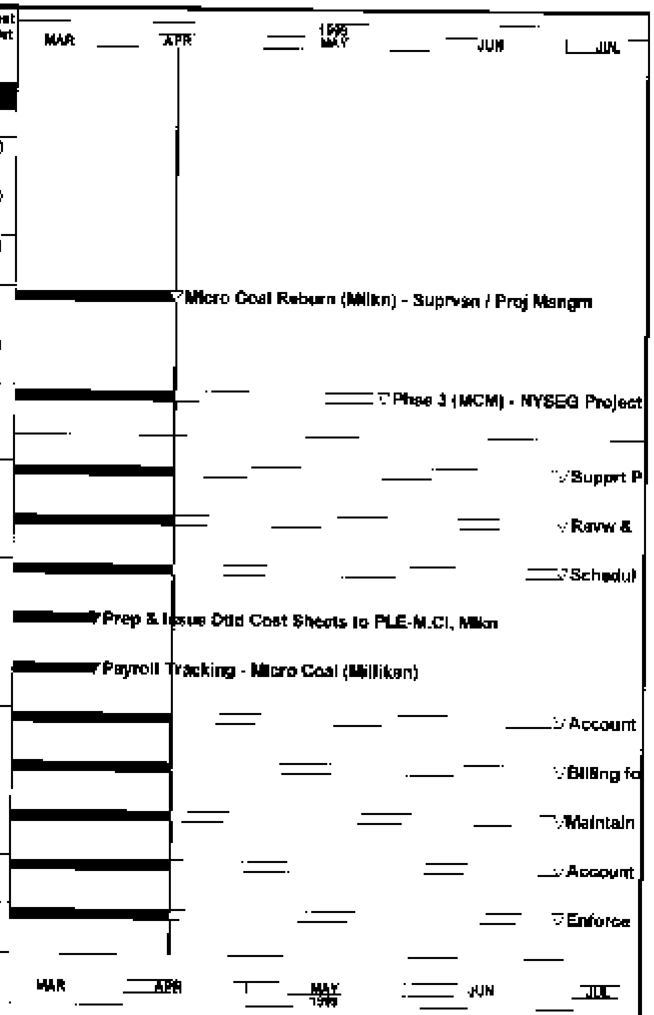
Milliken - Micronized Coal Project

Gen. Tech. Srvces. - Project Management Group

Activity ID	Activity Description	Early start	Actual Start	Early finish	Actual Finish	Rem Dur	Percent complete
Project Managment / Administration							
MS96007001	Pre-Award (MCM) - NYSEG Proj Management Support	05SEP95A	05SEP95	15MAR96A	15MAR96	0	100
MS96007002	Phse 1 (MCM) - NYSEG Project Management Support	01APR96A	01APR96	31JUL97A	31JUL97	0	100
MS96007003	Phse 2 (MCM) - NYSEG Project Management Support	01APR96A	01APR96	04SEP98A	04SEP98	0	100
MS96007032	Micro Coal Reburn (Milkn) Suprvsn / Proj Mangm	04AUG97A	04AUG97	15APR99		0*	97
MS96007058	Micro Coal Steering Commitee Meeting - Spring 98	15MAY98A	15MAY98	10SEP98A	10SEP98	0	100
MS96007047	Phse 3 (MCM) - NYSEG Project Management Support	01SEP98A	01SEP98	26MAY99		29	97
Proj. Mnagmnt-Cost Cntrl, Schdle, Admin							
MS96007045	Supprt Proj Budgt Managemnt-Micro Cl (Milkn)	06AUG96A	06AUG96	30JUN99		53	99
MS96007050	Revw & Procss P.O.s & Reqs Micro Cl (Mil)	18NOV96A	18NOV96	30JUN99		53	99
MS96007037	Schedule Updates - Micro Coal (Milkn)	02JAN97A	02JAN97	30JUN99		54	98
MS96007036	Prep & Issue Dtld Cost Sheets to PLE-M.Cl, Milkn	02JAN97A	02JAN97	31MAR99A	31MAR99	0*	100
MS96007034	Payroll Tracking - Micro Coal (Milken)	13JAN97A	13JAN97	31MAR99A	31MAR99	0*	100
MS96007035	Accounts Payable Invoicing - Micro Coal (Milkn)	07JUL97A	07JUL97	30JUN99		53	98
MS96007067	Billing for DOE, Tracking Sheet(Micro Coal Mil)	25AUG97A	25AUG97	30JUN99		53	95
MS96007061	Maintain all Electronic Data - Micro Coal, Milkn	15FEB98A	15FEB98	30JUN99		53	98
MS96007041	Accounts Receivable - Micronized Coal (Milken)	15MAY98A	15MAY98	30JUN99		53	85
MS96007060	Enforce Project Closeouts - Micro Coal (Milkn)	01DEC98A	01DEC98	30JUN99		53	90



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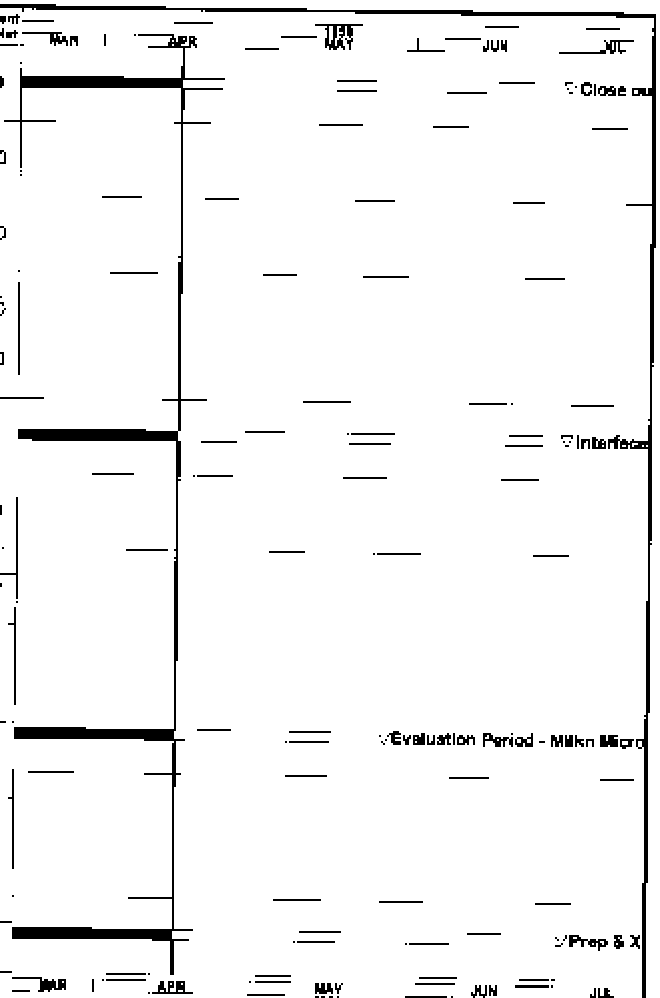
Activity ID	Activity Description	Early start	Actual Start	Early finish	Actual Finish	Rem Dur	Percent complet
	Proj. Mnagmnt-Cost Cntrl, Schdle, Admin						
MS96007046	Close out the Micronized Coal Project	04JAN99A	04JAN99	30JUN99		76	90
	Detailed Engineering (General)						
MS96007071	Phse 1-NYSEG Respnsibility. Micro Coal at Milkn	01APR96A	01APR96	31JUL97A	31JUL97	0	100
	Write Equipment Specifications						
MS96007020	Write Materl Specs-Mill/LNCFS Mods, Mic Cl Mlkn	15MAR98A	15MAR98	18SEP98A	18SEP98	0	100
	Award Contract for Consultant/Special Services						
MS9600701C	Negotiate\Sign Contract-ABB, Mic Cl, Mlkn	14JUN96A	14JUN96	04OCT96A	04OCT96	0	100
MS9600701[illegible]	Negotiate\Sign Contract-D B Riley, Mic Cl, Mlkn	14JUN96A	14JUN96	18OCT96A	18OCT96	0	100
	Cnsltnt/Outsde Enginrng Firm - Dsgn & Eng Work						
MS96007036	Interface with CONSOL - Micro Coal (Milkn)	02NOV98A	02NOV98	30JUN99		53	97
	Construction Work						
MS96007012	Assist ABB / Riley with Test, Mic Cl Mlkn	30SEP96A	30SEP96	31JAN97A	31JAN97	0	100
	Post Start-up Testing & Evaluation						
MS96007051	Milkn Micro Coal Parametric Testing	12MAR97A	12MAR97	26MAR97A	26MAR97	0	100
MS96007040	Conduct Testing Coordination Micro Coal (Milkn)	15APR96A	15APR96	12FEB99A	12FEB99	0	100
MS96007063	5[illegible] day Test Milkn Micro Cl	09NOV98A	09NOV98	30NOV98A	30NOV98	0	100
MS96007062	Evaluation Period - Milkn Micro Cl	04JAN99A	04JAN99	28MAY99		29	95
	Reports / Studies on Operations & Testing Reslts						
MS96007056	Devlp Parameters, Testing Data Colletn - MC/Milk	16NOV98A	16NOV98	15JAN99A	15JAN99	0	100
MS96007033	Testing Data Collection - Micro Coal (Milkn)	09NOV98A	09NOV98	16FEB99A	15FEB99	0	100
	Prep & Issue CoFndrs Topical Reports						
MS96007049	Prep & Xmit Cofndrs Topcl Reprts-Micr C (Mil)	17NOV97A	17NOV97	30JUN99		53	97



Project Start 15JUN93
Project Finish [illegible]
Data Date [illegible]
Run Date 22APR99

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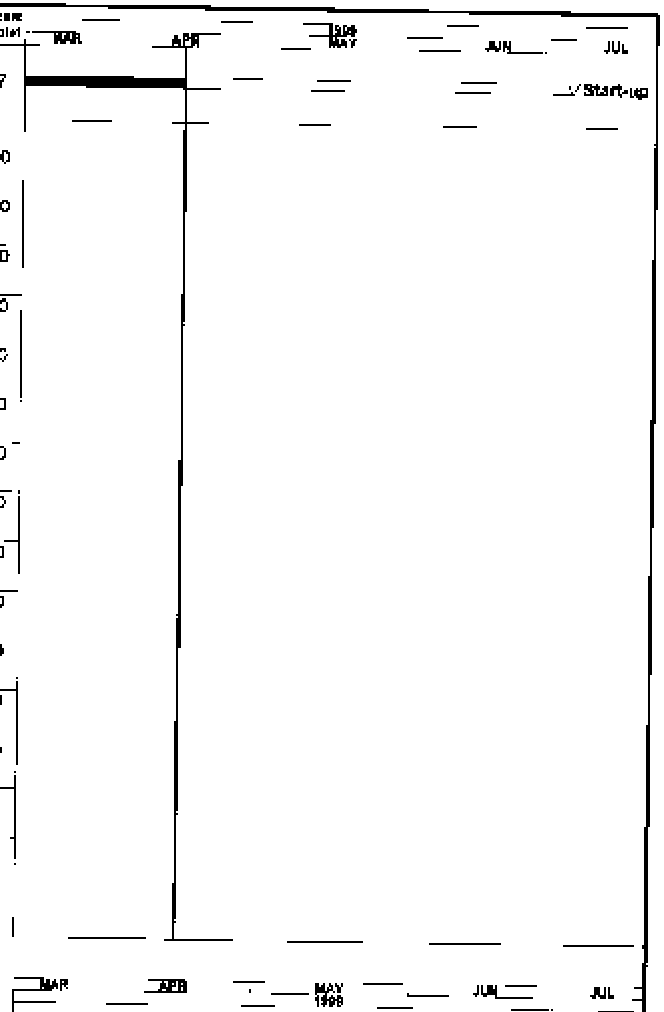
Activity ID	Activity Description	Early Start	Actual Start	Early Finish	Actual Finish	Rem Dur	Percent Complete
Prep & Issue CoFndrs Topical Reports							
MS980[illegible]012	Start-up Report - Micro Coal (Milkn)	04JAN99A	04JAN99	30JUN99		63	97
Prep & Issue CoFndrs Mnthly Progress Reports							
MS98007075	Prep & Issu Cofndrs Progress Reprt, Mic Cl-11/97	20NOV97A	20NOV97	25NOV97A	25NOV97	0	100
MS98007070	Prep & Issu Cofndrs Progress Reprt, Mic Cl-12/97	18DEC97A	18DEC97	23DEC97A	23DEC97	0	100
MS98007072	Prep & Issu Cofndrs Progress Reprt Mic Cl-08/97	15JAN98A	15JAN98	23JAN98A	23JAN98	0	100
MS980070[illegible]	Prep & Issu Cofndrs Progress Reprt, Mic Cl-09/97	20JAN98A	20JAN98	23JAN98A	23JAN98	0	100
MS98007074	Prep & Issu Cofndrs Progress Reprt, Mic Cl-10/97	20JAN98A	20JAN98	23JAN98A	23JAN98	0	100
MS98007077	Prep & Issu Cofndrs Progress Reprt Mic Cl-01/98	20JAN98A	20JAN98	23JAN98A	23JAN98	0	100
MS980[illegible]7	Prep & Issu Cofndrs Progress Reprt, Mic Cl-02/98	01MAR98A	01MAR98	20MAR98A	20MAR98	0	100
MS98007078	Prep & Issu Cofndrs Progress Reprt, Mic Cl-03/98	15MAR98A	15MAR98	28MAR98A	28MAR98	0	100
MS98007080	Prep & Issu Cofndrs Progress Reprt Mic Cl-04/98	21APR98A	21APR98	24APR98A	24APR98	0	100
MS98007051	Prep & Issu Cofndrs Progress Reprt, Mic Cl-05/98	20MAY98A	20MAY98	30JUN98A	30JUN98	0	100
MS98007382	Prep & Issu Cofndrs Progress Reprt, Mic Cl-06/98	25JUN98A	25JUN98	31AUG98A	31AUG98	0	100
MS98007003	Prep & Issu Cofndrs Progress Reprt Mic Cl-07/98	15JUL98A	15JUL98	15AUG98A	15AUG98	0	100
MS98007054	Prep & Issu Cofndrs Progress Reprt, Mic Cl-08/98	15JUL98A	15JUL98	15OCT98A	16OCT98	0	100
MS98007085	Prep & Issu Cofndrs Progress Reprt, Mic Cl-09/98	15SEP98A	15SEP98	25SEP98A	25SEP98	0	100
MS980[illegible]6	Prep & Issu Cofndrs Progress Reprt, Mic Cl-10/98	20OCT98A	20OCT98	23OCT98A	23OCT98	0	100
MS98007087	Prep & Issu Cofndrs Progress Reprt, Mic Cl-11/98	20NOV98A	20NOV98	23DEC98A	23DEC98	0	100



New York State Electric & Gas
Kodak Micronized Coal Project
Schedule Update Report

Activity ID	Activity Description	Early Start	Actual Start	Early Finish	Actual Finish	Rem Dur	Percent Complete
	Prep & Issue CoFndrs Mnthly Cost Status Rep.						
MS950C7043	Develop Cost Plan Micro Coal Project 1998	17NOV97A	17NOV97	21NOV97A	21NOV97	0	100
MS9500?035	Prep Mnthly Cost Status Reprt - Micro Cl Project	01OCT98A	01OCT98	12FEB99A	12FEB99	0*	100
	Prep & Issue CoFndrs Mnthly Schdle Status Reprt						
MS9850?053	Prep 3 month look-ahead Schdles-Micro Coal	07APR97A	07APR97	11DEC98A	11DEC98	0*	100
MS950C07C52	Prep Mnthly Cofndrs Schle Prfrmnce Updts-Mic Cl	15SEP97A	15SEP97	18DEC98A	18DEC98	0*	100
MS9?00?065	Develop Milestne Schdle Plan - Mic Cl 1998	08DEC97A	08DEC97	31DEC97A	31DEC97	0	100
	Milliken Maintenance Foreman						
	Construction Work						
MS500C7068	Phse 2-Ovrhaul Mill 1A1 on Blr 1 re Micronizng	06JUL98A	06JUL98	02NOV98A	02NOV98	0	100
MS950C?C35	Phse 2-Instal (4) Aero Tip Burnr Nozzles, Blr 1	08SEP98A	08SEP98	02NOV98A	02NOV98	0	100
	ABB / CE						
	Cnsltnt/Outsde Enginrng Firm - Dsgn & Eng Work						
MS950C7070	Phse 1-ABB/CE Responsibility Micro Coal at Milkn	01APR96A	01APR96	31JUL97A	31JUL97	0	100
MS950C07C12	ABB Develop testing parmeter, Mic Cl Milkn	30SEP96A	30SEP96	06DEC96A	06DEC96	0	100
MS950C?C??	Phse 2 ABB/CE Responsibility, Mic Cl Milkn	30SEP98A	30SEP98	19JUN98A	19JUN98	0	100
MS950C7017	Develop Report LNCFS Modificatn, Mic Cl Milkn	27MAR97A	27MAR97	20JUN97A	20JUN97	0	100
	Construction Work						
MS950C7015	Test ABB Modifcatns - Mic Cl Milkn	10MAR97A	10MAR97	26MAR97A	26MAR97	0	100
	CONSOL						
	Cnsltnt/Outsde Enginrng Firm - Dsgn & Eng Work						
MS950C7080	Phse 2-CONSOL Responsibility-Micro Coal at Milkn	06JUL98A	06JUL98	10SEP98A	10SEP98	0	100
MS950C7C08	Phse 3-CONSOL Responsibility-Mic Cl Milkn	16OCT98A	16OCT98	28MAY99		29	0

1999

MAR APR MAY JUN JUL

▽ Phse 3-CONSOL Responsibilit

MAR APR MAY 1999 JUN JUL

Project Start 26JUN95

Project Finish

Data Date 16APR99

Run Date

© Primavera Systems, Inc.

Early Bar

Progress Bar

Critical Activity

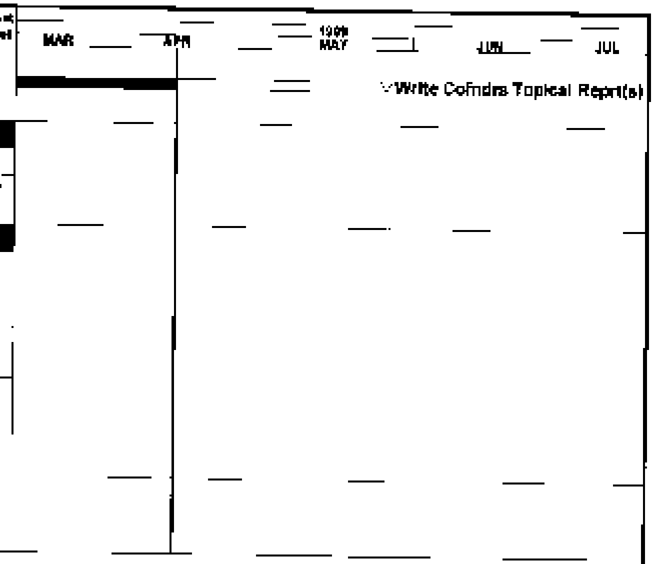
New York State Electric & Gas

Kodak Micronized Coal Project

Schedule Update Report

Date | Revision | Checked | Approved

Activity ID	Activity Description	Early Start	Actual Start	Early Finish	Actual Finish	Rem Dur	Percent Complete
Prep & Issue CoFndrs Topical Reports							
MS98007022	Write Cofndrs Topical Reprt(s)-Milkn Micro Cl	04JAN99A	04JAN99	28MAY99		29	75
Injector Reburn Contractor							
Construction Work							
[illegible]	Phse 1-Injctr Contor Resprsblty-Micro Coal, Mlk	01APR96A	01APR96	31JUL97A	31JUL97	0	100
Riley Stoker							
Cnsltnt/Outsde Enginrng Firm - Dsgn & Eng Work							
[illegible]	Phse 1-Riley Test Resprsblty, Micro Coal at Mlk	01APR96A	01APR96	31JUL97A	31JUL97	0	100
MS98007014	Riley Develop testing parmeter, Mic Cl Mlkn	03JAN97A	03JAN97	10JAN97A	10JAN97	0	100
[illegible]	Phse 2-Riley Test Resprsblty, Mic Cl Mlkn	06JAN97A	06JAN97	31JAN97A	31JAN97	0	100
[illegible]	Riley-Develop Reprt,Mill Mods/Test-Mic Cl Mlkn	28JAN97A	28JAN97	31JAN97A	31JAN97	0	100
Construction Work							
MS98007015	Test Riley Modifcatns - Mic Cl Mlkn	27JAN97A	27JAN97	28JAN97A	28JAN97	0	100



New York State Electric & Gas
Kodak Micronized Coal Project
Schedule Update Report

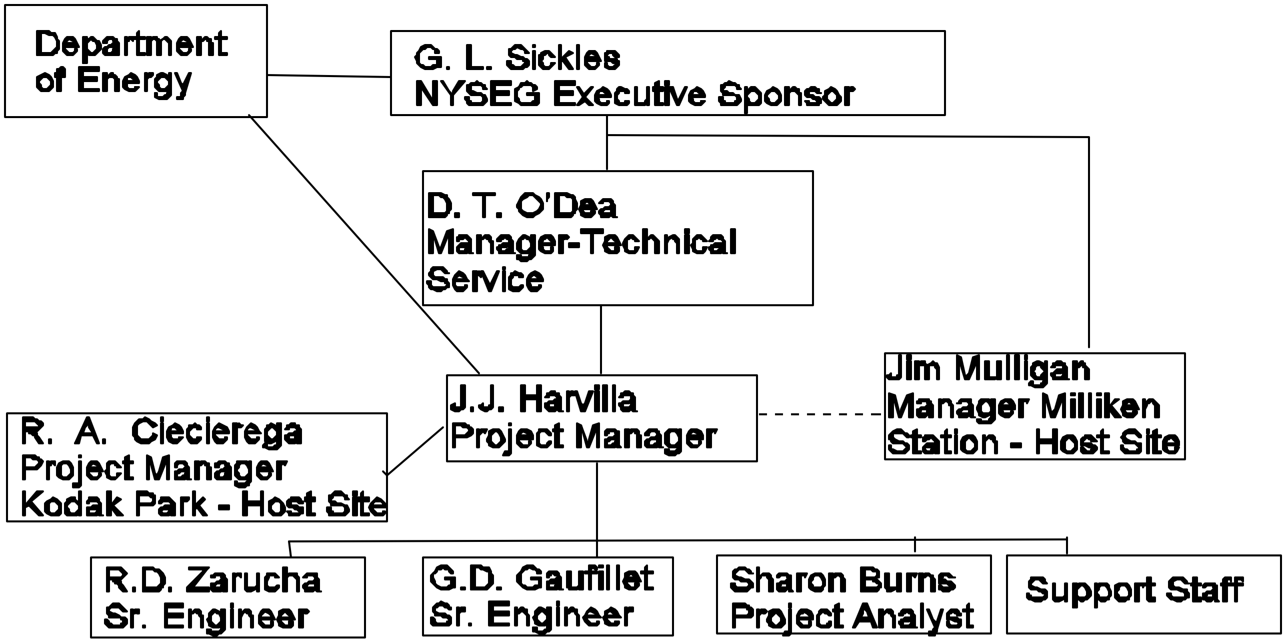


Figure 1.5.2.1-1 Project Management Chart

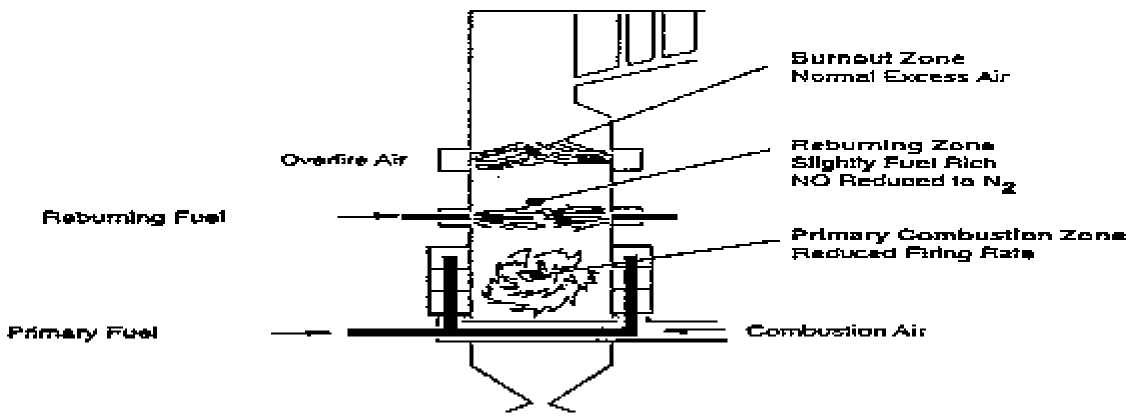


Figure 2.1.1-1 Application of reburning technology to a utility boiler.

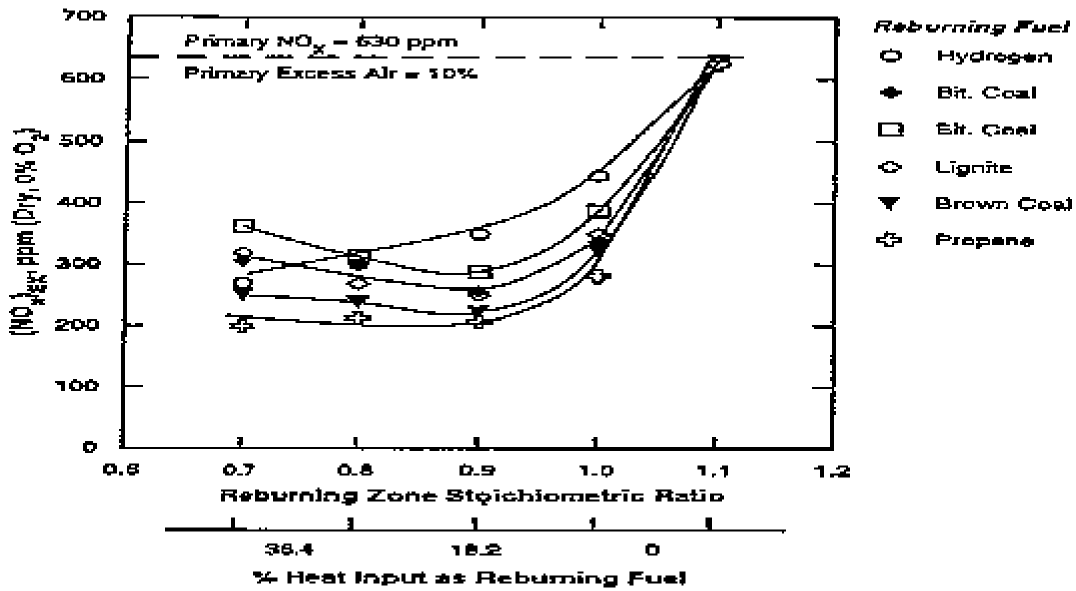


Figure 2.1.2-1 Impact of reburning zone stoichiometric ratio and reburning fuel type on reburning performance.

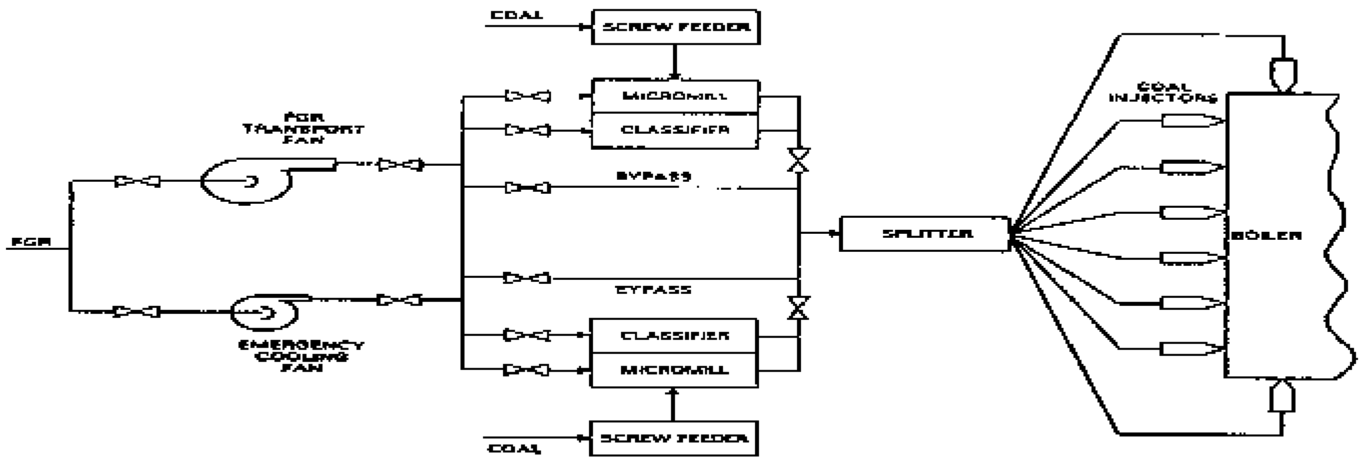


Figure 2.1.3-1 Micronized Coal Feed System

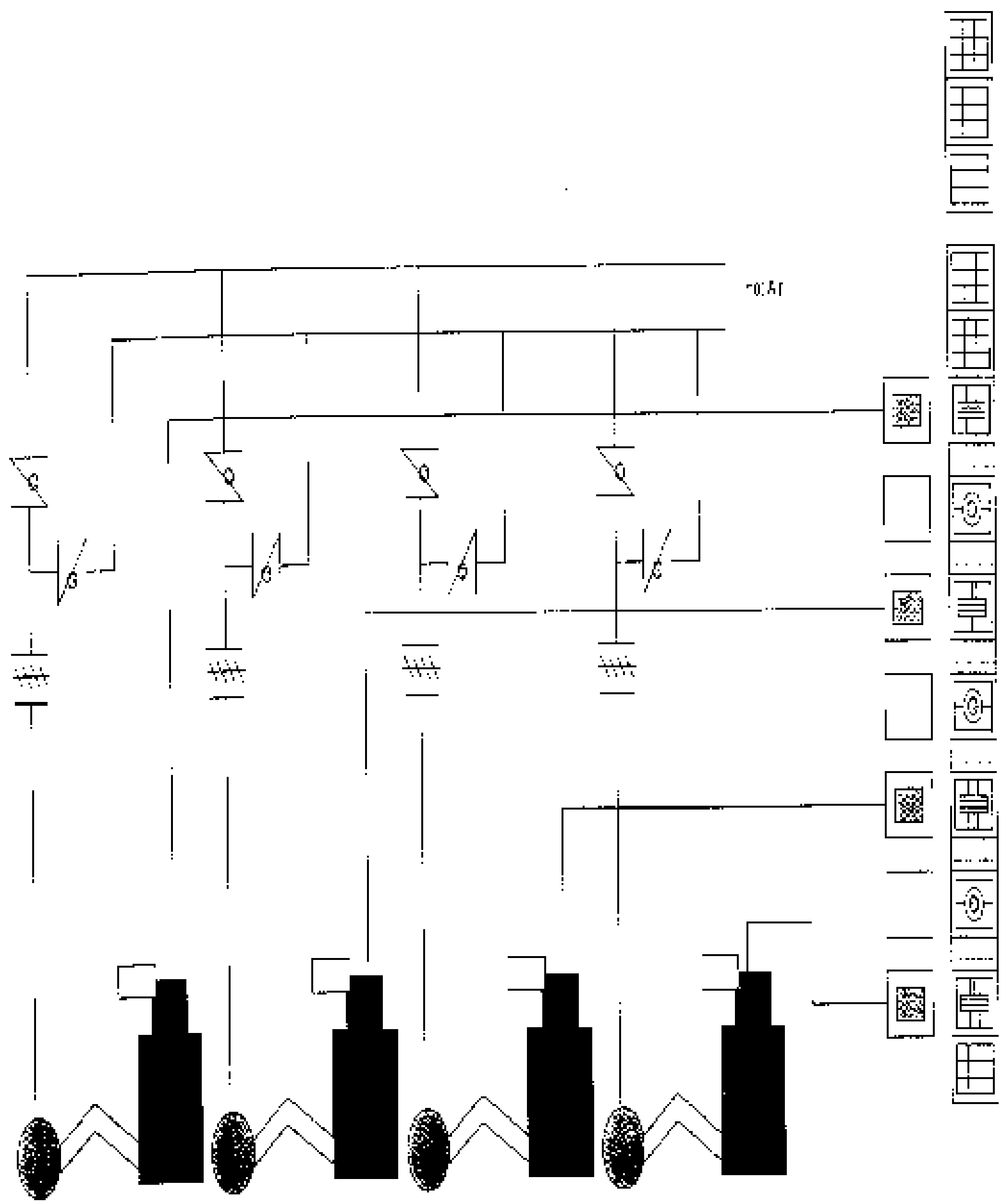


Figure 2.4-1 Milliken Station Simplified Fuel System Overview

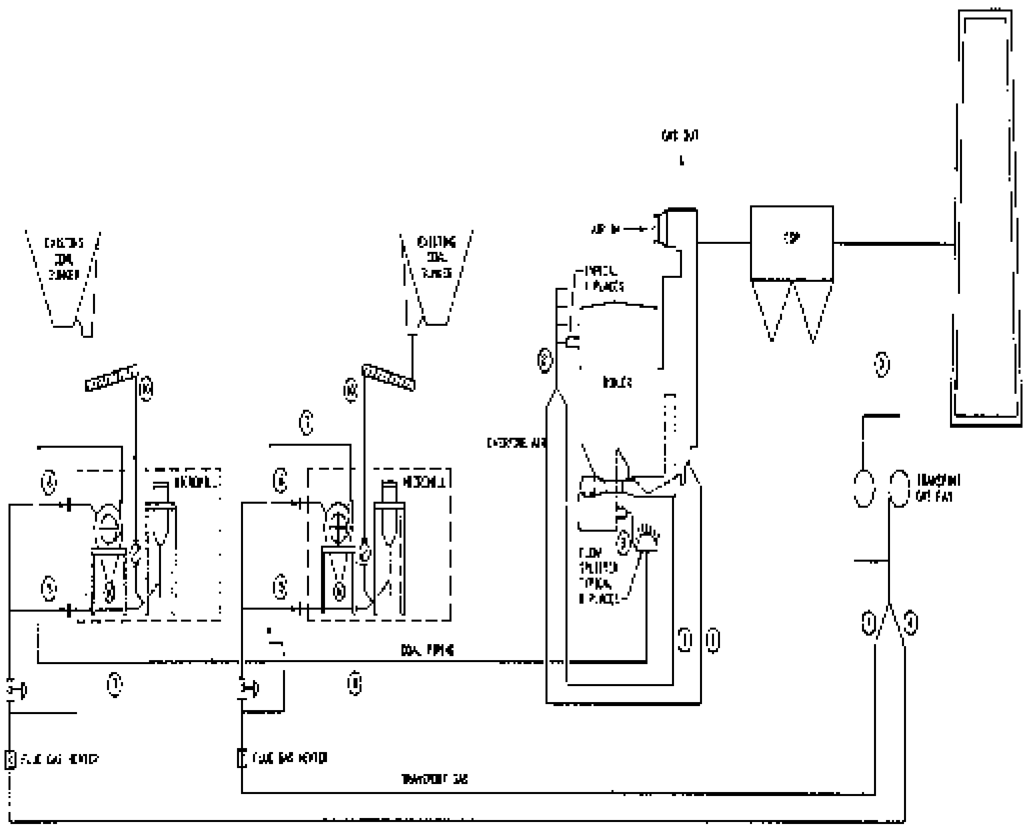


Figure 2.4-2 Coal and Combustion Air Process Flow Sheet - Kodak Boiler #15

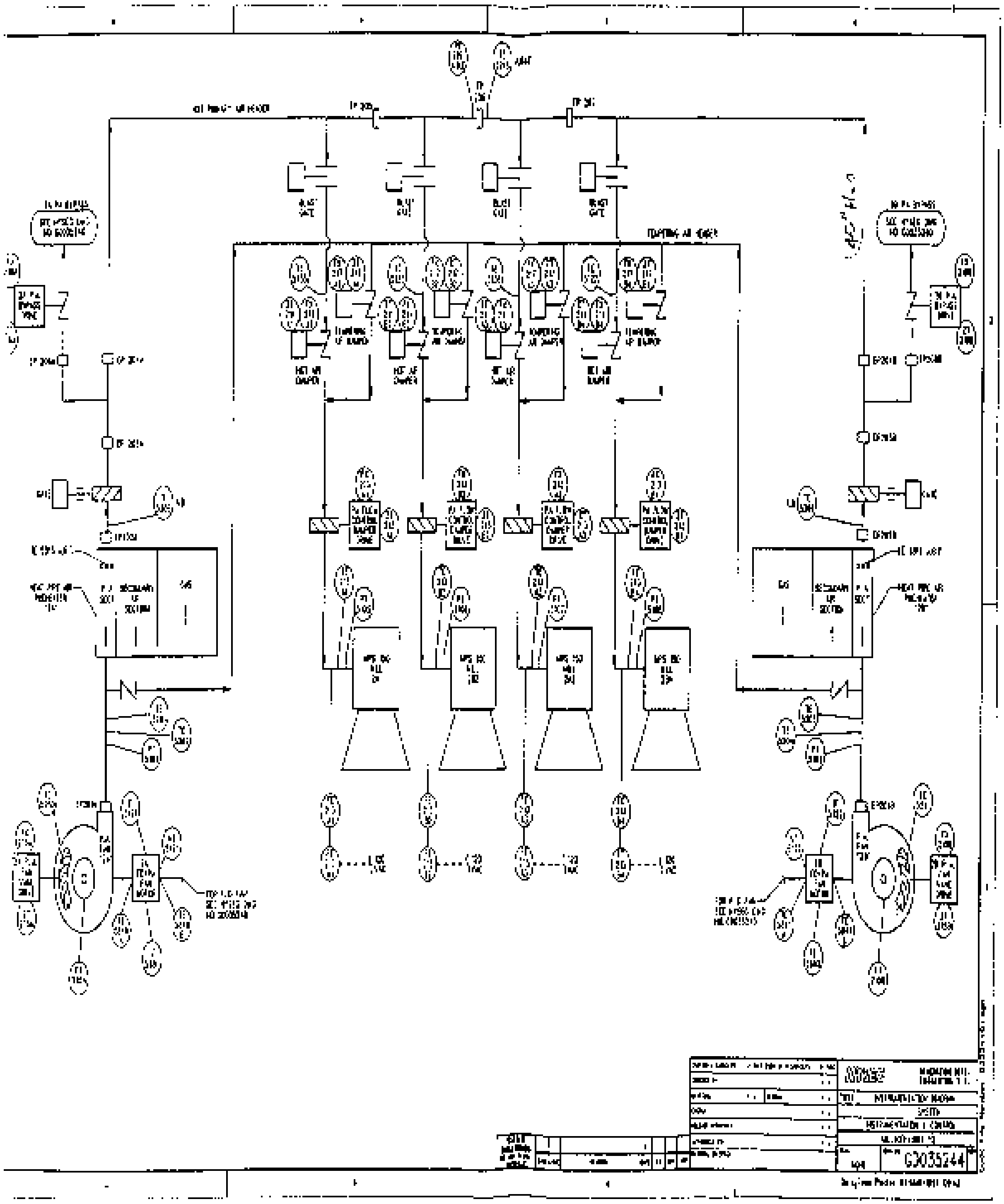


Figure 2.6-1 Coal Circuit - Milliken Station Unit 1

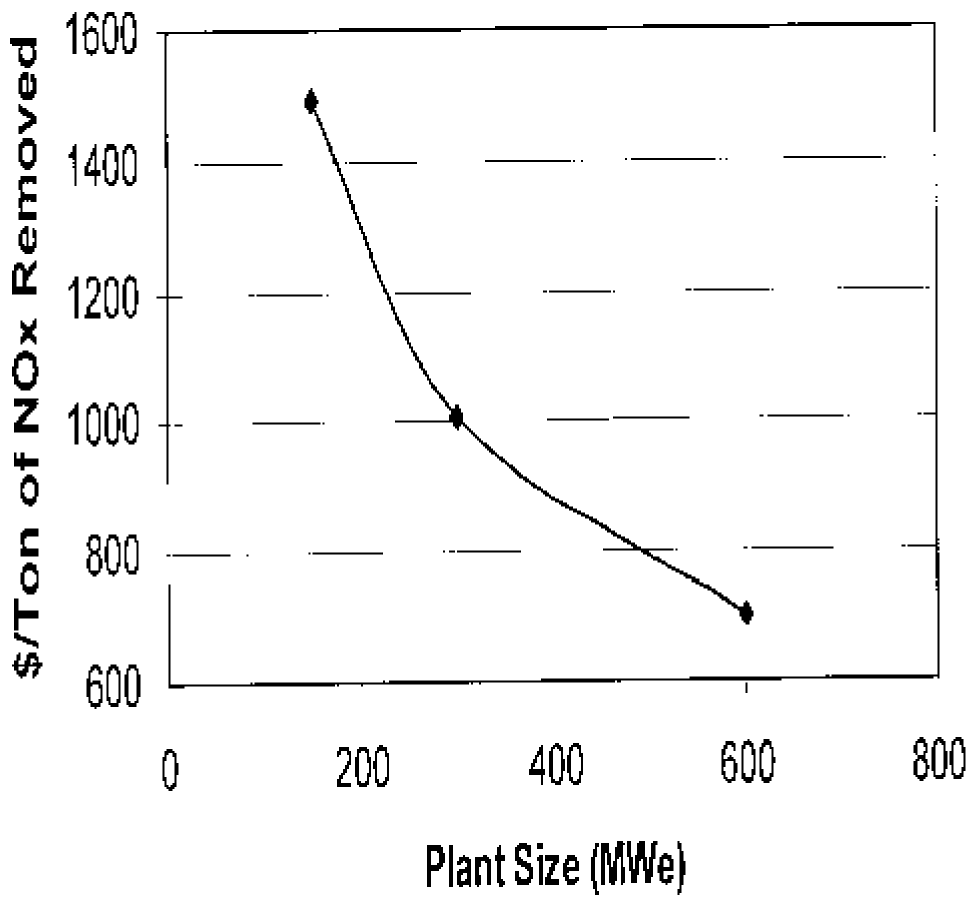


Figure 7.1-1 Sensitivity to Plant Size (65% Capacity Factor)
T-Fired Boiler

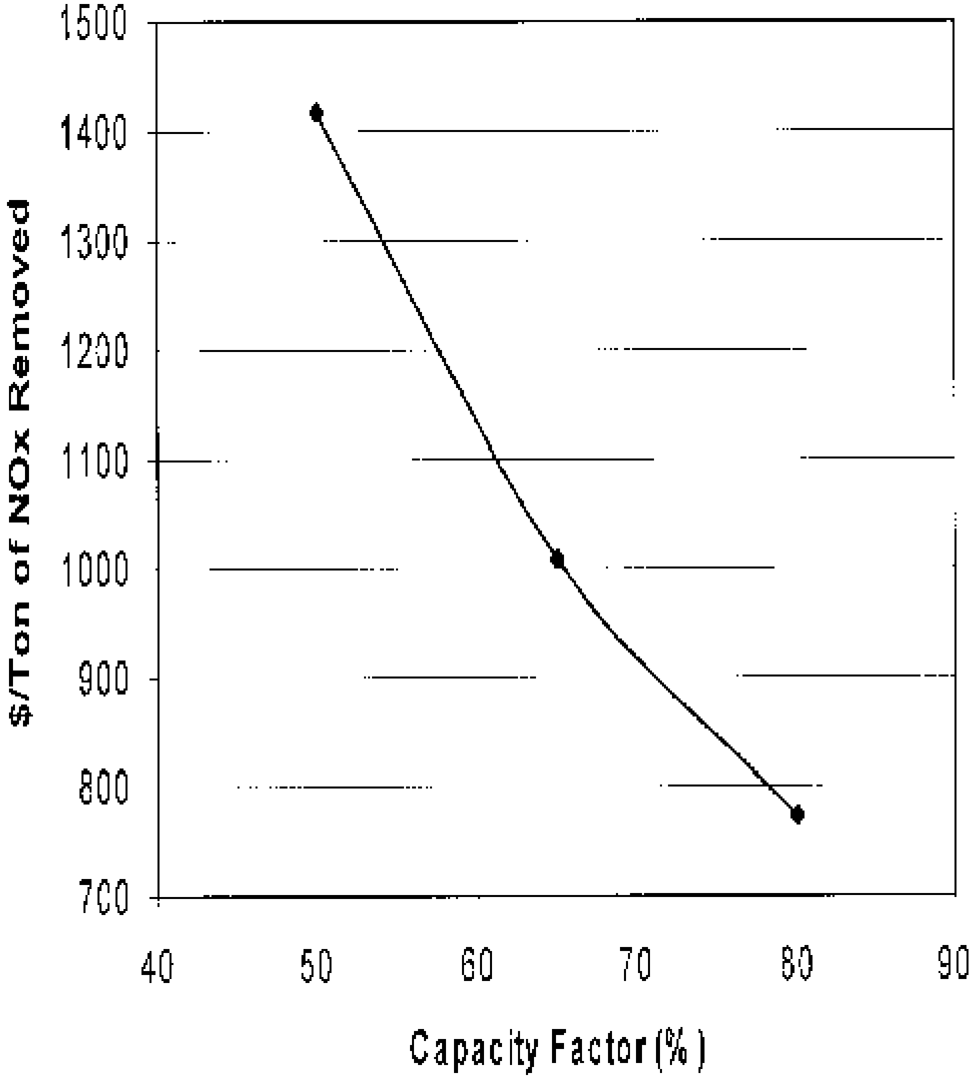


Figure 7.1-2 Sensitivity to Plant Capacity Factor (300 MWe)
T-Fired Boiler

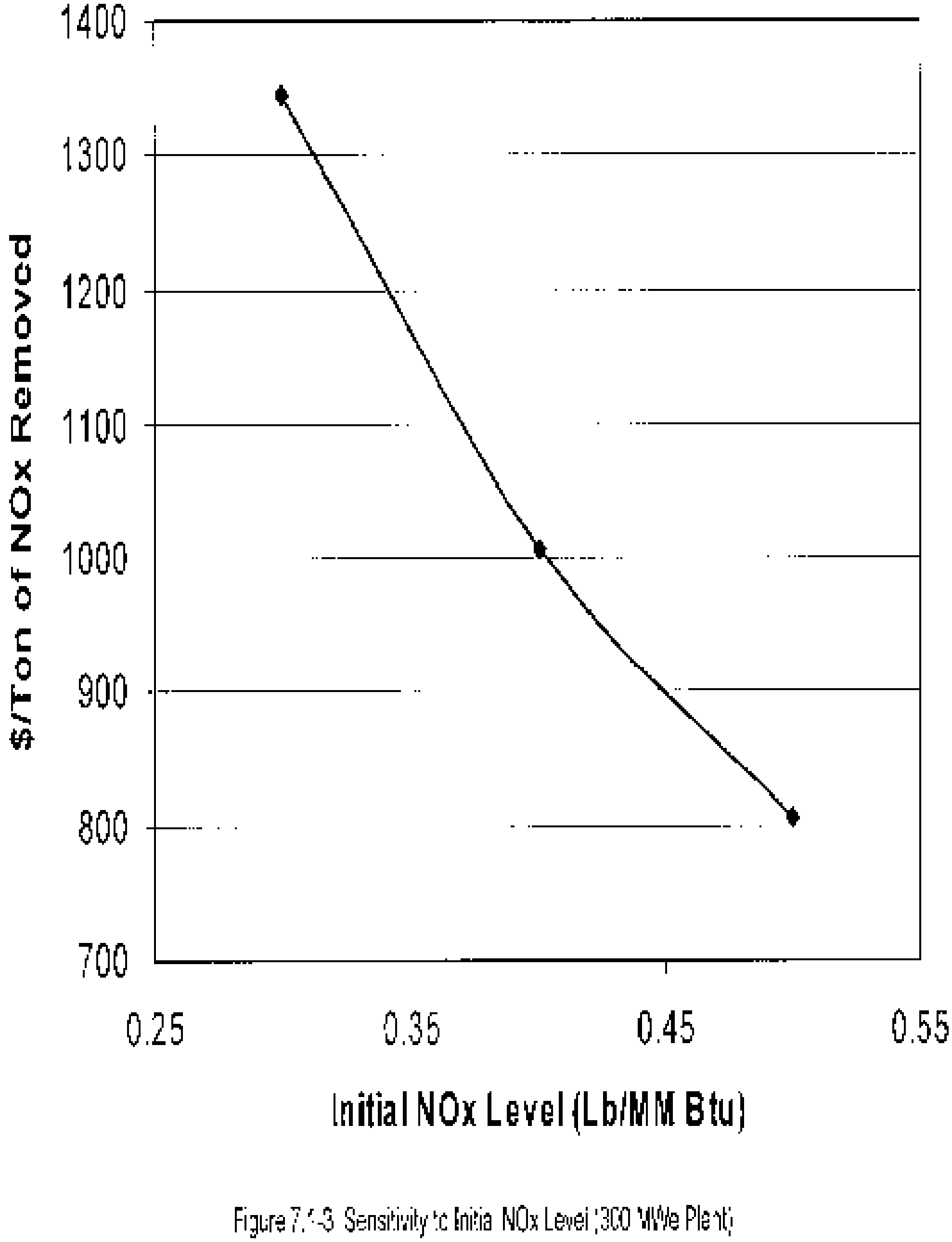


Figure 7.1-3 Sensitivity to Initial NOx Level (300 MWe Plant)
T-Frac Boiler

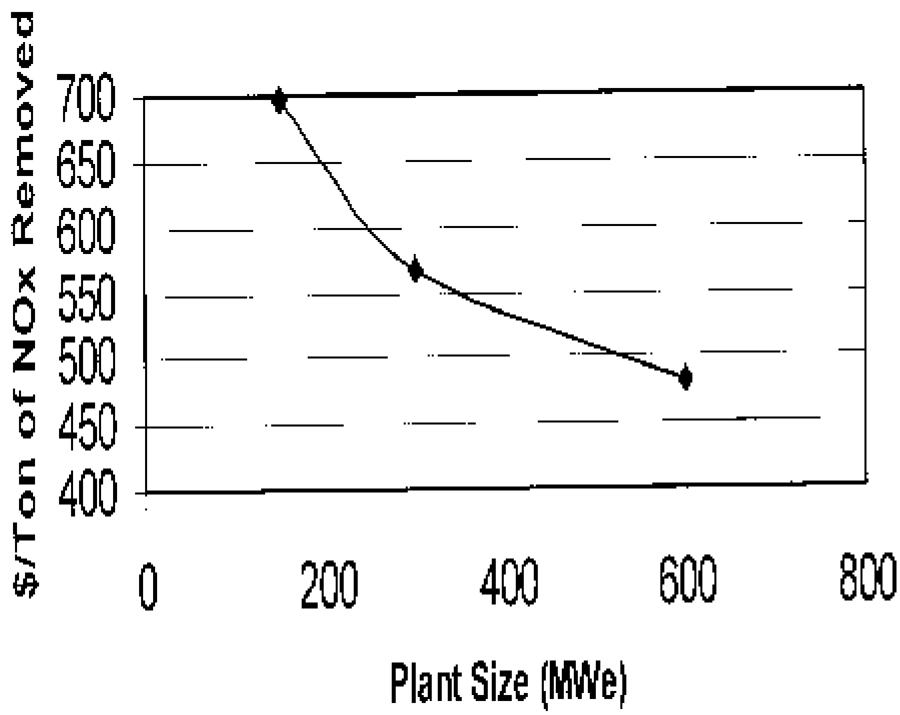


Figure 7.2-1 Plant Size Sensitivity (65% Capacity Factor)
Cyclone Boiler

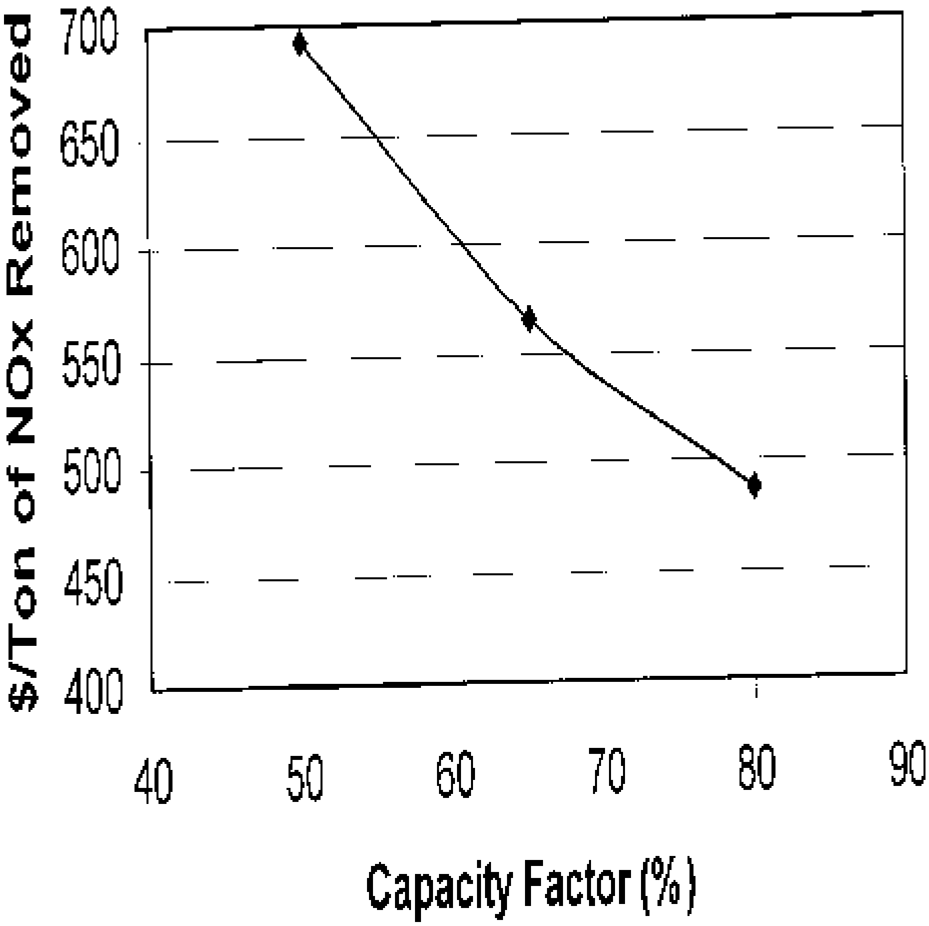


Figure 7.2-2 Capacity Factor Sensitivity (300 MWe Plant)
Cyclone Boiler

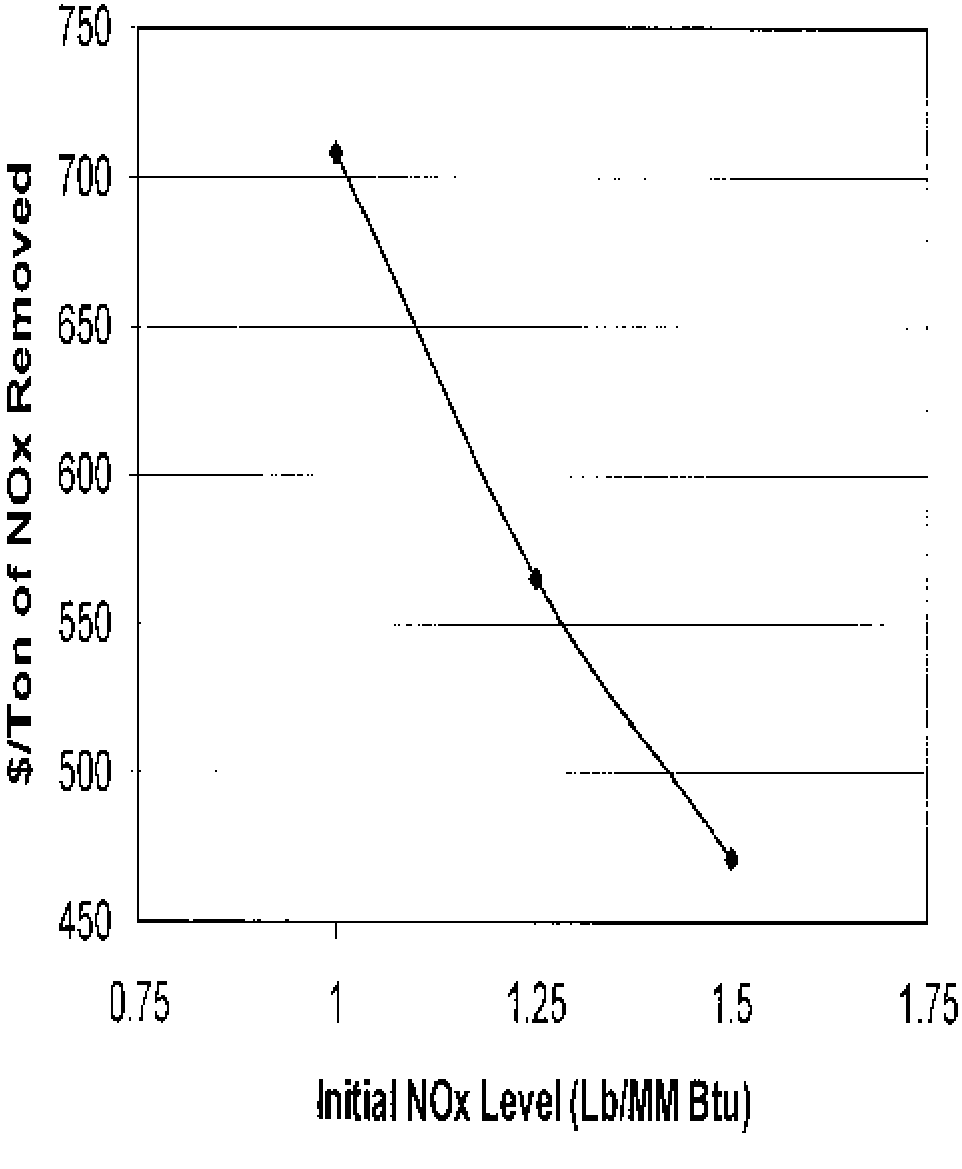


Figure 7.2-3 Sensitivity to Initial NOx Level (300 MWe Plant)
Cyclone Boiler