FUELS STRATEGIES FOR COMPLIANCE FOR A PRE-NSPS 225 MWe BOILER

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Presented at the
International Joint Power Conference
San Diego, California
October 6-10, 1991

RST-97

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ABSTRACT

The recently passed Clean Air Act Amendments have caused utilities and owners of stationary sources over 25 MWe to consider various strategies to comply with regulated emissions limits of SO_2 and NO_x within allotted periods defined in Phase 1 or Phase 2 of the Amendments. In many cases, the alternative of fuel switching, combined with potential boiler modifications, is weighed against the cost of flue gas scrubbing. This paper presents the performance of a pre-NSPS 225 MWe boiler that fuel switched in the mid-1970s for fuel economic reasons and subsequently lost generating capability. The need for reclaiming that lost capability resulted in boiler modifications, rather than switch to a compliance bituminous coal. Further emission control considerations are presented that consider fuel costs and equipment modification costs for bringing the boiler into total compliance with the goals of the Clean Air Act Amendments, and the regaining of lost generating capability.

INTRODUCTION

The original boiler and boiler auxiliaries designs were established based on a high sulfur bituminous coal specification that would be currently classified as noncompliance coal. The coal was switched in the mid-1970s to a subbituminous coal from Wyoming. It is generally known that variations in the rank of coal have considerable impact on the moisture, heating value, grindability, slagging, and fouling index of the coal. The use of this lower rank coal resulted in the loss of the boiler's ability to carry full rating and its operation at a much lower level of boiler efficiency. Fuel cost savings can justify such a derating, assuming the need for rated generator output is not critical. However, fuel switching can result in higher than expected maintenance costs and loss of availability, which alters the original factors on which the fuel switch was based. A further investment in modifying plant equipment design or a switch back to a more forgiving coal was required to restore the boiler's capability to a reasonable and practical operating load. The recent changes to the Clean Air Act by the Amendments have caused the utility to re-evaluate fuels' operating cost savings versus capital expenditure on equipment to be in compliance with the Amendments. Planning for the operation of equipment over its useful life is not a static situation, and conditions will continue to change relevant to fuel economics and socially regulated requirements. Designing for operating flexibility to accommodate various combinations of fuels and provide margins over currently regulated levels for SO_2 and NO_x is needed.

ORIGINAL EQUIPMENT DESIGN

The boiler under review in this paper is a natural circulation reheat design with a main steam capacity of 1,502,000 lbs/hr, at 2591 psig and 1005°F. **Table 1** lists the basic boiler performance factors. The boiler was originally designed for base load operation with natural gas as the primary fuel and a high sulfur bituminous coal as an alternate fuel. Maximum Continuous Rating (MCR) of the boiler required all three pulverizers to be in service. Twelve dual-fuel, pre-NSPS style burners with a rating at MCR of 170 million BTUs per hour (MKB/hr) on coal were supplied. The boiler has three radiant superheater wing walls in the furnace and a parallel backpass for reheat temperature control.

In the 1960s, boiler designs were cost driven and not influenced by regulations for NO_x. Consequently, the furnace size of this boiler is small considering today's standards for combustion control of NO_x formation when firing coal. Furnace size was further influenced by the fact that the boiler was designed with natural gas as the primary fuel. **Figure 1** shows the sectional side view of the subject boiler. The highlighted area in the furnace burner zone (called the basket area) is one of the driving design rules today for NO_x formation during unstaged combustion. By today's standards, this boiler firing the originally specified coal would result in NO_x levels of 1.12 #/MKB and SO_2 levels of 5.6 #/MKB, both of which would considerably exceed emission levels cited in the Clean Air Act Amendments.

The coal was switched in the 1970s to a Powder River Basin Coal (subbituminous) from the original bituminous coal for economic reasons. At the same time, the boiler was modified from pressurized furnace to balanced draft operation and the mode of operation changed to cycling from base loaded. The relative fuel costs between natural gas, bituminous coal, and the subbituminous Powder River Coal are shown in **Table 2** as well as the financial impact to plant operating fuel costs. The economic benefit firing Powder River Coal compared to original bituminous coal is several millions of dollars per year. The properties of the Powder River Coal are compared to the original design fuel in **Table 3**. Firing the Powder River Coal had an influence on flue gas weight due to the increased moisture in the coal. For example, the flue gas weight at a steam flow of 832,000 lbs/hr is approximately 10% higher when firing Powder River Coal than with the original bituminous coal. The reflective nature of the Powder River ash deposits in the furnace and the fouling that occurred in the horizontal convective surfaces had a significant impact on increasing both the furnace exit gas temperature and the economizer exit gas temperature, as compared to the original coal. The boiler operation was severely limited by heat transfer problems caused by these characteristics of the Powder River fuel fired in the original boiler configuration.

The operating problems encountered after the fuel switch in 1976 were:

- Poor fineness from the pulverizers at increased coal flows
- Poor flame stability
- Increased furnace slagging
- Primary superheater fouling
- Horizontal reheater fouling
- High primary superheater spray
- High reheater spray
- Overheating in upper convection pass sidewalls

The as-built boiler's capability to carry load as a result of the fuel switch was to be derated to 55% of MCR or 832,000 lbs/hr. The resultant boiler performance is shown in **Table 1**. The boiler was operating at a 3% loss of efficiency. Projected levels of NO_x and SO_2 were positively influenced by the fuel switch to levels of 0.76 #/MKB and 0.86 #/MKB respectively, at the derated capacity. The shift in heat absorbed in the various segments of the boiler, compared to the original bituminous coal, are shown in **Table 4**. This shift had a tremendous negative impact on boiler availability due to fouling in the downpass. This resulted in failure of carbon steel tubing in the partition wall between the downpasses and failures in the upper convection pass sidewall adjacent to the convection pass front wall screen. Fouling was further aggravated by the poor fineness from the pulverizers and poor flame stability of the burners. The availability was reduced over 10% as the unit thermally aged under these operating conditions. The combined losses of 45% capacity, 3% boiler efficiency, and over 10% availability were the reasons to consider boiler modifications when using the Powder River fuel to recover unit capability and maintain the economic advantages of this coal.

MODIFIED DESIGN

When considering a modification of this magnitude, a review of the various fuel alternatives must be made. Compliance with imminent SO_2 emissions regulations would force the fuel options to be low sulfur Powder River Coal, a low sulfur bituminous coal, and natural gas. Bituminous coal would bring the operation of the boiler back to the original as-designed condition, with replacement of the pressure part components to improve availability. Natural gas is a base fuel and is also used as a supplementary fuel cofired in combination with the Powder River Coal. One of the facts needed for evaluation of fuel operating cost was the maximum capacity of the modified boiler firing Powder River Coal. The predicted performance of the proposed modified boiler is shown in **Table 5** at 1,200,000 #/hr steam flow. The primary focus of the modified design was to cool the flue gas leaving the furnace and again, before entering the downpass. The revised design is shown in **Figure 2**. This modification included the addition of four water-cooled, natural circulating wing walls spaced between the existing radiant superheater wing walls. Retractable sootblowers were added under the leading edge of these wing walls. These modifications would achieve the Furnace Exit Gas Temperature (FEGT) design criteria of 2240°F, where current operating experience was acceptable. Secondly, a vertical section of primary superheater was installed behind the screen entering the horizontal downpass, and the side-to-side spacing of the top horizontal primary superheater sections was increased. Material upgrades of various pressure parts were also made. These changes reduce the temperature entering the downpass correcting the overheating problems in the sidewall and fouling of the top sections in the downpass. Thirdly, Deutsche Babcock MPS Pulverizers were used to replace the existing pulverizers, upgrading the capacity by 10%. This increased pulverizer capacity provided an improvement of pulverized coal fineness well in excess of predicted values resulting in improved burner stability and decreased furnace slagging. These particular MPS pulverizers are equipped with a static SLK classifier, a hydraulic loading system, and a planetary gearbox that enables the installation of a higher capacity pulverizer in a confined building space. **Figure 3** shows the pulverizer configuration. The overall reliability of the new pulverizer system has been demonstrated, and maintenance costs are similarly reduced with longer wear element life.

The water-cooled wing wall concept used in the modified design is a form of evaporative surface that has been used by Riley Stoker Corporation in many central station plants over the past 30 years. With these pressure part modifications and the installation of new MPS pulverizers supplied by Deutsche Babcock, the predicted recovery of steam flow was 25% to a level of 1,200,000 lbs/hr when firing Powder River Coal . The cofiring of coal and natural gas was designed to bring the boiler steam flow back to the original rating of 1,500,000 lbs/hr at a fuel split equivalent to 1,200,000 #/hr steam flow from coal and the remainder from natural gas. The economics of this fuel mix, when compared to both compliance and noncompliance bituminous coal, are shown in calculations in **Table 2**. Using this fuel comparison, the payback for the modifications would be approximately four years, given the rough rate of return calculation made in **Table 6**.

The predicted performance of the boiler at 1,200,000 lbs/hr and the initial performance data confirms the design criteria shown in **Table 5**. The airheater exit gas temperature was decreased 20°F and about 65,000 lbs/hr of reheater spray was eliminated, both of which improve boiler efficiency and unit heat rate. The NO_x and SO_2 are predicted to essentially stay the same at 0.8 #/MKB and .86 #/MKB, respectively. The modified boiler has operated at loads in excess of 80% on Powder River Coal and at loads of 1,600,000 lbs/hr on natural gas. Combustion induced vibration encountered with the original design when firing natural gas at loads above 205 MWe have been eliminated through adjustment in burners, allowing boiler loads to reach 225 MWe. The modifications have resulted in actual performance as shown in **Table 5**, which exceeded the guaranteed levels.

Table 7 summarizes the positive results on emissions due to the fuel switch to Powder River Coal. These results are essentially at no cost, given the fuel cost savings more than offset the boiler modification costs. Appendix A shows the calculation method used to relate the cost of various technologies for emission reduction based on the yearly operating conditions set forth in **Table 2**. Appendix A also shows the case of fuel switching versus scrubber installation cost to meet SO_2 regulations. The Acid Rain Technology Effectiveness (ARTE) of $417 per ton of SO_2 removed was calculated for use of the noncompliance bituminous coal with a scrubber.

FUTURE COMPLIANCE ISSUES

The Clean Air Act Amendment will require Phase 1 SO_2 levels at 2.5 #/MKB by 1995 and Phase 2 levels of 1.2 #/MKB (baseline SO_2 x 120 percent) by 2000.

The sustained use of Powder River Coal is the most economical choice based on the comparison with low sulfur, compliance bituminous coal (0.6 to 0.8% sulfur in the coal) and particularly when compared to the installed cost of a scrubber. Both the cofiring scenario and the low sulfur, bituminous compliance coal meet the Phase 2 SO_2 levels of 1.2 #/MKB. The savings in operating fuel costs for various load factors of the cofiring scenario over compliance coal are summarized in **Table 2**. The operating fuel cost difference between cofiring natural gas and Powder River Coal, instead of noncompliance coal at MCR, is negligible. SO_2 emission levels under cofired conditions at MCR are predicted to be 0.69 #/MKB and well within compliance today for the proposed legislative requirements. Flue gas scrubbing never becomes a real consideration at installed costs of between 175 to 225 $/kilowatt. **Table 7** shows ARTE for various fuel scenarios, as well as compliance coal versus noncompliance coal with a scrubber.

The remaining compliance issue is NO_x. Considering the use of only the Powder River Coal and natural gas, there are several scenarios (shown in **Table 8**) which compare all conditions, including the original design. The operating levels of NO_x with the pre-NSPS burner was 1.12 #/MKB on the original bituminous coal and 0.79 #/MKB on Powder River Coal. The high moisture content of the subbituminous coal, low fuel nitrogen, and the reduced boiler load were factors in determining the lower NO_x levels with the original design.

The Clean Air Act Amendments require that NO_x levels be 0.5 #/MKB by 1995 and stipulates that low NO_x burners be used as the control technology. A low NO_x coal burner is designed to slow the combustion process, which retards the formation of NO_x from fuel nitrogen without deterioration of combustion efficiency. **Figure 4** shows Riley Stoker Corporation's patented CCV® low NO_x coal burner which forms four concentrated coal streams to delay combustion of char. The cases of low NO_x burners (both unstaged and staged) are presented in **Table 8**. Low NO_x burners unstaged are marginal at compliance levels of 0.5 #/MKB at 80% boiler load (Case V); however, these low NO_x burners do result in a reduction in NO_x of 35%, as shown in Case III. The combustion efficiency and the primary and secondary air side pressure drop, of either unstaged pre-NSPS burners and unstaged low NO_x are equivalent. The Acid Rain Technology Effectiveness (ARTE) for this unstaged low NO_x burner installation is calculated at ~215 \$/ton of NO_x removed considering the incremental cost of installing low NO_x burners firing Powder River Coal.

The low NO_x burners can be staged below a stoichiometry of 1.0 at the burners providing a reduction in NO_x that is linear with corresponding reduction in burner zone stoichiometry. The use of an Over Fire Air (OFA) system brings the predicted NO_x levels down to 0.34 lbs/MKB at 0.9 stoichiometry, which provides suitable margins below the legislative values. Staging of burners is an added expense and complication that must be performed with expertise to assure the boiler life expectancy is not reduced. For older boilers with burners mounted in a common windbox, care must be taken to balance the secondary air to the burners. For example, the use of low NO_x burners with modulating shrouds on each burner and equipped with individual air measuring devices can assure secondary airflow balance within + or - 5%. The primary and secondary air side pressure drops of unstaged low NO_x burners and staged low NO_x burners are equivalent, since the secondary flow area of the staged burners would be smaller than unstaged to account for the air diverted to the OFA ports.

Typically, staged combustion results in increased unburned carbon in the ash. Although the Powder River Coal is a more reactive coal, the use of a rotating or dynamic classifier on the pulverizer firing the top level of burners must be considered in order to shorten the distance for coal particle burnout needed with staged combustion. The fineness characterization of a rotating classifier (type SLS) compared to a stationary classifier (type SLK) is shown in **Figure 5**. This increase in the slope of the Rosin-Rammler Curve, which graphs the fineness distribution of pulverized coal, produces burnout in less residence time. Although this fineness distribution with the SLS classifier doesn't produce micronized coal, the distribution or percentage passing the 100 mesh screen is considerably improved over conventional classification, and not at the expense of pulverizer capacity. As a benefit, rotating classifiers deliver a more uniform and balanced mixture of primary air and pulverized coal to the burner lines compared to static classifiers. The rotating classifier drive adds ~20 KW power consumption. Considering the incremental cost for staged low NO_x burners with an OFA system and the addition of an SLS classifier to one pulverizer compared to pre-NSPS burners, the Acid Rain Technology Effectiveness is 203 \$/ton. If all three pulverizers were equipped with rotating classifiers, the unburned carbon in the ash would be less than 1%. Based on Powder River Coal at 15 \$/ton delivered, the resultant fuel savings would be equivalent to the operating cost and demand charge for the power of the rotating classifier.

Cofiring a combination of natural gas and

Powder River Coal gives the potential to try natural gas reburning. Reburning is a method of NO_x reduction by injecting natural gas in an oxygen deficient environment and combusting part of the gas at the point of injection. For this application, natural gas is assumed to be injected without flue gas into a reducing zone resultant from staged combustion. The remainder of the air is introduced as OFA above the reducing zone and the completion of the burnout is achieved prior to entering the furnace exit. The configuration shown in **Figure 6a** provides the point of entry of natural gas and OFA. For this design, the predicted NO_x level at 80% boiler load using natural gas as a reburning fuel is better by only ~0.04 #/MKB than with staged low NO_x burners when firing Powder River Coal only (**Table 8**, Case IX versus VII). The cofired fuel costs of the reburning scenario are higher, as are the investment costs for the gas reburning system. The Acid Rain Technology Effectiveness is calculated at ~460 $/ton.

Reburning with coal as a NO_x reduction method is also possible, although the reduction may not be as large as with natural gas due to the higher stoichiometry in the reducing zone. **Figure 6b** shows the furnace configuration when using the upper row of burners for coal reburning. This method requires the ability to bias the burner input between the different elevations of burners. Riley's shrouded CCV® low NO_x burners have modulating secondary air control that can be integrated with pulverizer control for biased firing. The use of a rotating classifier is a necessity due to the lower stoichiometry in the reburning zone. The total hardware and operating costs remain the same as with staged combustion at astoichiometry of 0.9. Coal reburning is still under development, but is applicable to low sulfur and low fuel nitrogen coals such as thePowder River Coal.

SUMMARY

The Clean Air Act Amendments are focused primarily on reduction of sulfur dioxide and secondarily, on NO_x. The Phase 1 requirements for this 225 MWe boiler will be focused on NO_x, as the earlier fuel switch to low sulfur Powder River Coal places this unit in compliance through Phase 2 SO_2. Fuel switching has been costly in lost generation, both in capacity reduction and in availability. A modification to the boiler and the pulverizer system has restored this capability from 55% load to 80% on Powder River Coal only, to +100% load on natural gas, and is anticipated to restore capacity to 100% load by cofiring Powder River Coal with natural gas. These changes have eliminated the need to fuel switch to more expensive bituminous compliance coal as well as the need to install expensive flue gas scrubbing systems. The availability of natural gas at the plant enables the owners to consider several options for NO_x compliance throughout the load range. The most effective of all scenarios studied, according to a comparison of Acid Rain Technology Effectiveness (ARTE) values, is the strategy to provide staged firing using shrouded low NO_x burners, a rotating classifier feeding the upper elevation of burners, and maximizing the use of Powder River Coal. Margins in NO_x levels below regulation, low carbon in the ash, compliance with SO_2 regulation, and the ability to cofire the boiler to loads greater than MCR have all been made possible by the modified boiler and pulverizer design.

TABLE 1

Original and Post Fuel Switch
Boiler Performance

	Original Coal	Post Switch Powder River Coal
Main Steam Flow, lbs/hr	1,502,000	832,000
Reheat Steam Flow, lbs/hr	1,301,000	818,000
Final Steam Temperature, °F	1005	1005
Final Reheat Temperature, °F	1005	1005
Temp. of Gases Leaving Furnace, °F	2270	2235
Temp. of Gases Leaving Economizer, °F	690	644
Temp. of Gases Leaving Airheater, °F (corrected)	269	276
Excess Air in Economizer Exit Gases, %	20	13
Temp. of Air Entering Airheater, °F	90	80
Temp. of Air Leaving Airheater, °F	606	581
Pounds of Coal Per Hour	160,900	160,115
Pounds of Air Per Hour	1,754,000	1,072,800
Pounds of Flue Gases Per Hour	1,931,000	1,223,700
Pressure at Economizer Inlet, psig	2900	2580
Pressure at Steam Drum, psig	2727	2525
Pressure at Superheater Outlet, psig	2591	2485
Pressure at Reheater Inlet, psig	583	360
Pressure at Reheater Outlet, psig	559	345
Heat Release, $BTU/hr/ft^3$	16,050	11,300
Heat Release, $BTU/hr/ft^2$	83,094	58,300
Overall Efficiency %	88.94	85.92

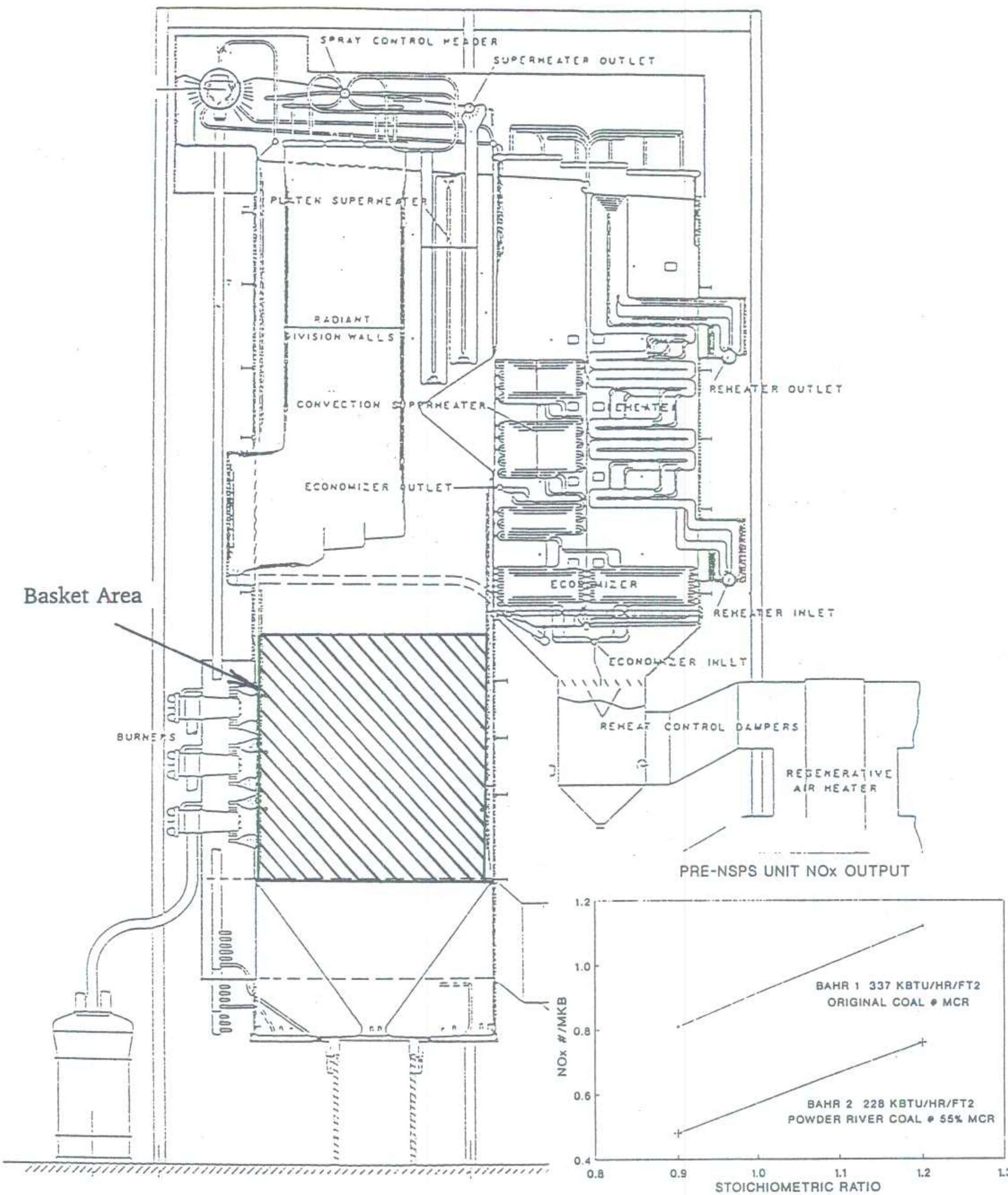

SPRAY CONTROL HEADER
SUPERHEATER OUTLET
PLATEN SUPERHEATER
RADIANT
DIVISION WALLS
CONVECTION SUPERHEATER
REHEATER
REHEATER OUTLET
ECONOMIZER OUTLET
ECONOMIZER
Basket Area
REHEATER INLET
ECONOMIZER INLET
BURNERS
REHEAT CONTROL DAMPERS
REGENERATIVE
AIR HEATER
PRE-NSPS UNIT NOx OUTPUT
BAHR 1 337 KBTU/HR/FT2
ORIGINAL COAL @ MCR
BAHR 2 228 KBTU/HR/FT2
POWDER RIVER COAL @ 55% MCR
NOx #/MKB
STOICHIOMETRIC RATIO
1.2
1.0
0.8
0.6
0.4
0.8
0.9
1.0
1.1
1.2
1.3

Figure 1

TABLE 2

Fuel Option Cost Differential

	55%	80%		MCR
Unit Output (MWe)	148	185		225
Steam Flow (#/hr)	832,700	1,200,000		1,500,000
Hours Operating at Load (hrs)(5)	3942	876		438
Noncompliance Coal Flow (TPH)(1)	48.7	65.9		80.5
Compliance Coal Flow (TPH) (2)	47.4	60.8		73.6
Powder River Coal Flow (TPH)(3)	80.1	100.9		98.8
Cofired Gas Flow (MCFH)(4)	0	0		400
Noncompliance Fuel Cost ($/hr)	1705	2307		2818
Compliance Fuel Cost ($/hr)	2133	2736		3312
Powder River Fuel Cost ($/hr)	1202	1514		1482
Cofired Nat. Gas Cost ($/hr)	0	0		1440
Cofired Cost ($/hr)	1202	1514		2,922
Operating Fuel Cost Differentials (OM&R)				
Cofired to Noncompliance ($)	1,983,000	695,000		-45,000
TOTAL			saved	2,633,000
Cofired to Compliance ($)	3,670,000	1,070,000		170,000
TOTAL			saved	4,910,000
Noncompliance to Compliance ($)	1,687,000	376,000		216,000
TOTAL			saved	2,279,000

Calculated Capacity Factor 42.8%

(1) Fuel Cost 30 to 40 $/ton (avg. 35 $/ton)
(2) Fuel Cost 40 to 50 $/ton (avg. 45 $/ton)
(3) Fuel Cost 15 $/ton
(4) $2.85 $/MKB off-peak and 6.60 $/MKB peak. Weighted cost 3.60 $/MKB.
(5) 60% Yearly Operation

TABLE 3

Properties of Original Noncompliance and Powder River Basin Coals

Ultimate Analysis of Coal	**Original Coal As Received**	**Powder River As Received**
Moisture	8.40	30.79
Ash	10.20	5.43
Sulfur	3.38	0.35
Nitrogen	1.10	0.53
Carbon	66.15	47.51
Hydrogen	4.77	3.53
Oxygen	6.00	11.86
BTU Content	12,100	8115
Mineral Analysis of Ash (%)**		
Phosphorus Pentoxide	-	0.90
Silicon Dioxide	14.00	37.00
Ferric Oxide	20.40	4.66
Aluminum Oxide	7.00	14.40
Titanium Dioxide	-	1.41
Manganese Dioxide	-	0.05
Calcium Oxide	28.6	20.78
Magnesium Oxide	1.2	4.73
Potassium Oxide	-	0.48
Sodium Oxide	-	1.48
Sulfur Trioxide	28.2	11.30
Barium Oxide	-	0.55
Strontium Oxide	-	
0.41		
Undetermined	0.60	1.85
Grindability		
HGI	-	67*
Fusion Temperature of Ash (°F)		
Reducing Zone		
Initial	2300	2080
Softening	2450	2117
Hemispherical	-	2138
Fluid	2580	2198

* at 18.75% moisture

** Ash analysis for the Original Coal is a typical analysis for bituminous coals from Southeastern Kansas. The analysis was taken from The United States Department of the Interior, Bureau of Mines, Technical Paper 679, "Analyses of Ash From Coals of the United States".

TABLE 4

Water and Steam Side Heat Absorption Patterns

Percentages of Heat Absorbed *(1)(2)*

	Original Coal 1,502,000 PPH Load	Powder River Coal 832,000 PPH Load
Furnace Waterwalls	42%	37%
Superheaters	34%	31%
Reheater	15%	22%
Economizers	9%	10%
(1) Flue gas weights (#/hr)	1,931,000	1,200,000
(2) Calculated FEGT (°F)	2270	2235

TABLE 5

Predicted Performance of Modified Boiler

	Powder River Coal	**CoFiring Coal & Gas**	**Actual Data Powder River Coal**
Main Steam Flow, lbs/hr	1,200,000 *	1,502,000	1,129,200
Reheat Steam Flow, lbs/hr	1,044,000	1,301,000	1,017,000
Superheater Spray Flow, lbs/hr	27,570	56,200	15,400
Reheat Spray Flow, lbs/hr	0	0	0
Temperature of Feedwater Entering Economizer, °F	470	480	447
Drum Pressure, psig	2590	2640	2605
Final Steam Temperature, °F	1005	1005	1007
Final Steam Pressure, psig	2500	2500	2527
Reheat Inlet Temperature, °F	671	705	608
Reheat Inlet Pressure, psig	465	580	400
Reheat Outlet Temperature, °F	1005	1005	1004
Reheat Outlet Pressure, psig	445	555	378
Kbtu Added to Steam Per Hour	1,208,600	1,496,700	1,168,000
Kbtu Added to Reheat Per Hour	187,800	212,200	219,200
Total Kbtu Output Per Hour	1,396,400	1,708,900	1,387,200
Temperature of Gases Leaving Furnace, °F	2235	2390	-
Temperature of Gases Leaving Economizer, °F	740	795	686
Temperature of Gases Leaving Airheater (Uncorrected), °F	285	300	295
Temperature of Air Entering Airheater, °F	80	80	93
Temperature of Air Leaving Airheater, °F	690	735	619
Pounds of Coal Per Hour	201,690	197,680	194,260
Pounds of Gas Per Hour	-	18,380	-
Pounds of Combustion Air Per Hour	1,510,100	1,830,260	1,419,300
Pounds of Flue Gas Leaving Boiler Per Hour	1,700,300	2,034,850	1,604,800
Heat Release BTU/hr/Cu Ft	14,640	17,935	14,310
Heat Release BTU/hr/Sq Ft	56,830	70,390	55,380
Overall Efficiency %	85.31	85.22	86.52

* Guaranteed steam flow was 1,100,000 lbs/hr.

Modified Boiler Sections

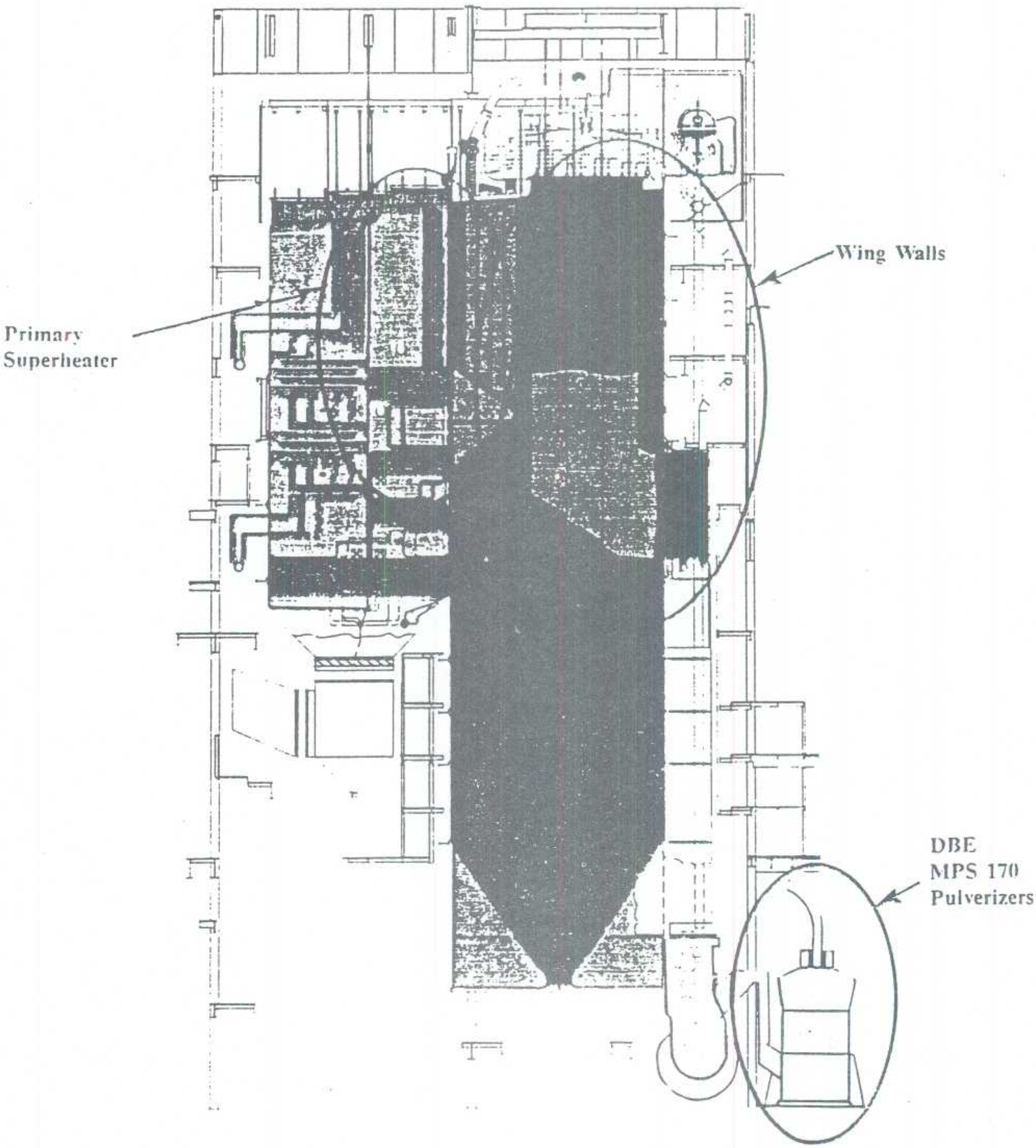
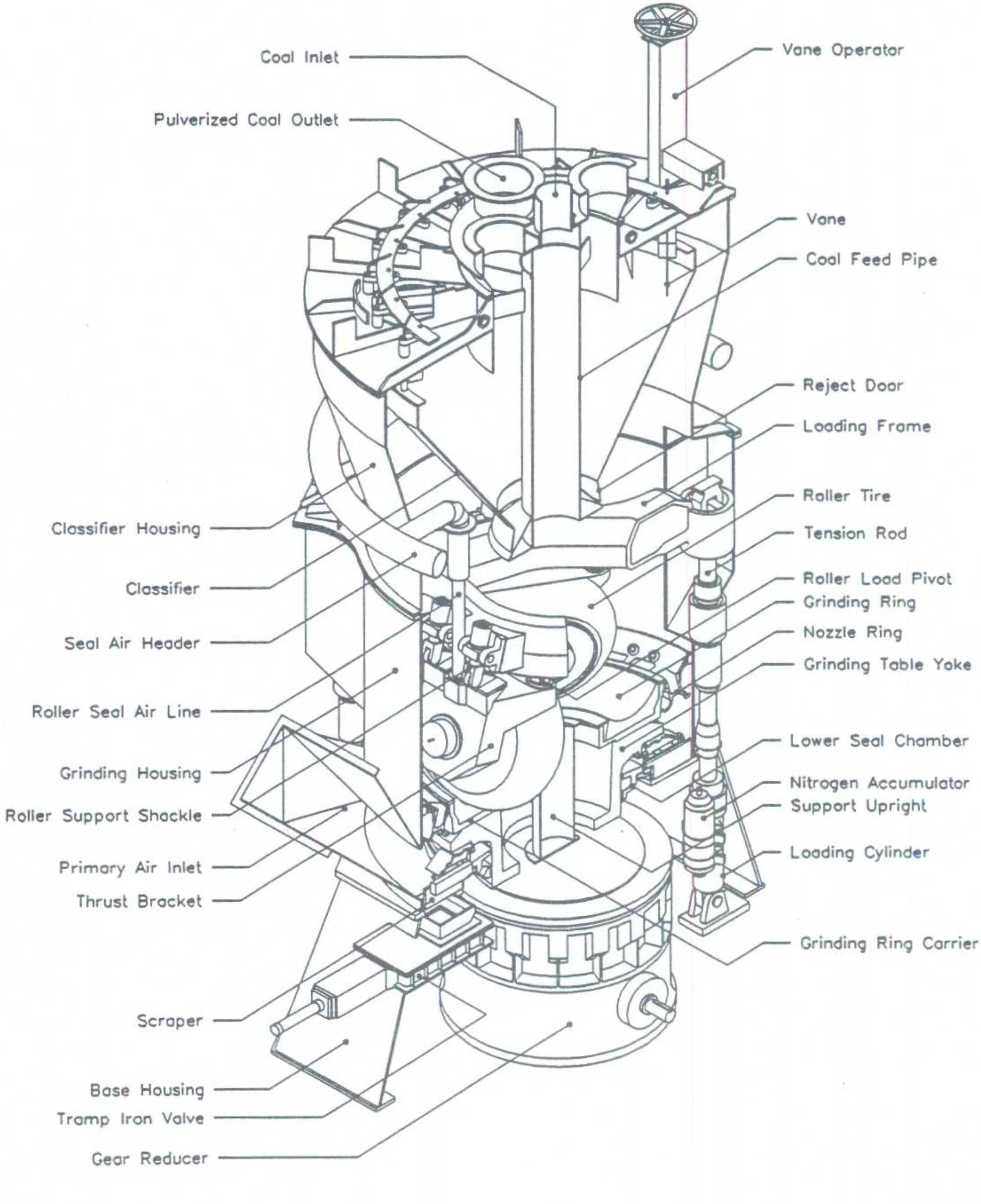


Figure 2



Type MPS Roller Mill - Model 170

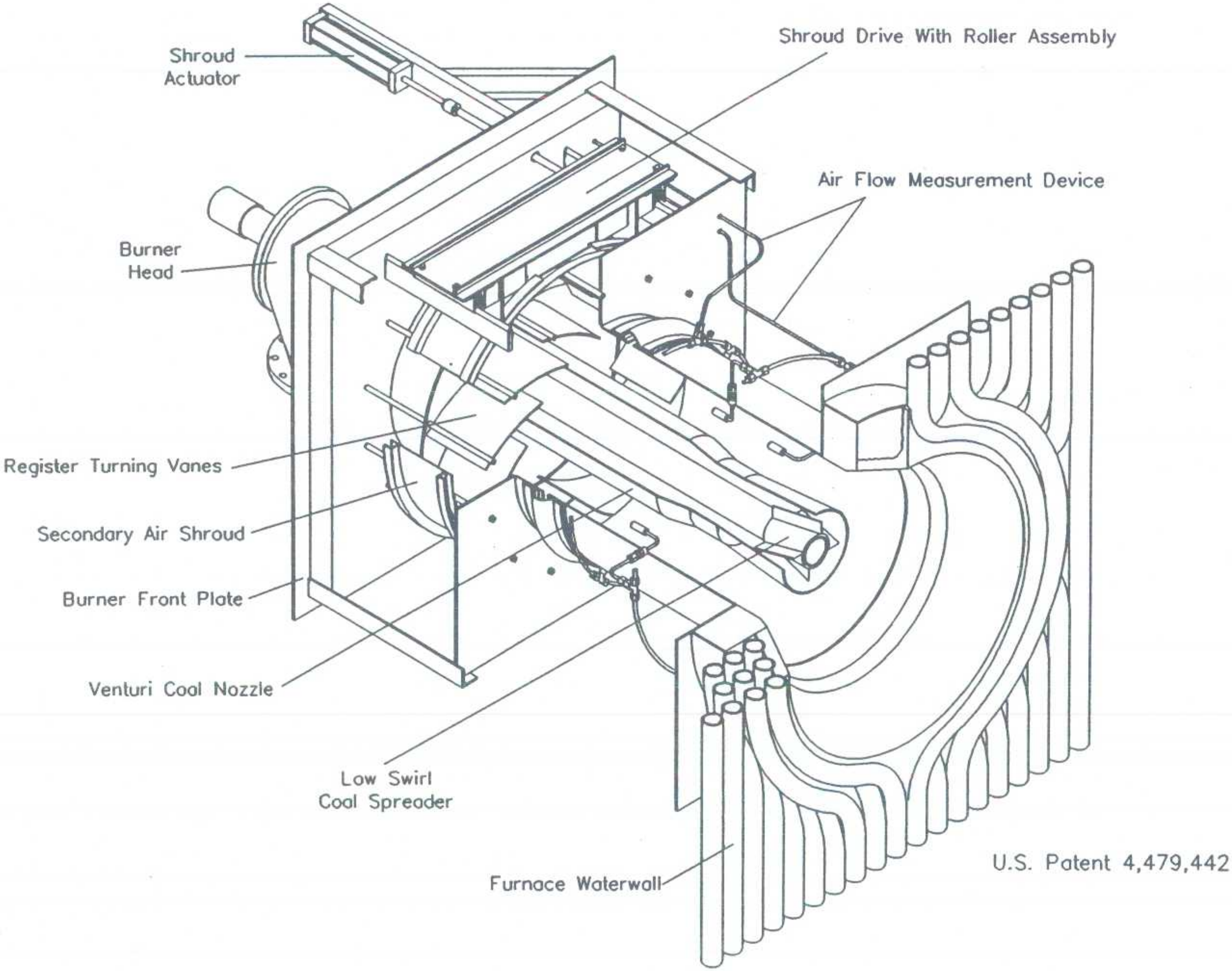
Figure 3

TABLE 6

Boiler Modification Internal Rate of Return

Scenario: Cofiring Powder River Coal with natural gas versus compliance bituminous coal.

Investment	$18,000,000
Minimum Retrofit Life	10 years
Interest	10% / annum
Fuel Escalation	5%
Fuel Savings in Year 1	$4,910,000
Net Present Value	$16,870,000
Internal Rate of Return	28.7%



<u>Figure 4</u> Riley Controlled Combustion Venturi (CCV) Burner with Model 90 Register

TABLE 7

Emission Performance Comparisons
Powder River Coal vs. Compliance or Noncompliance Bituminous Coal

Boiler Load	- MCR -		
	NO_x (4) #/MKB	SO^2 #/MKB	Aux. Power KW
Noncompliance Bituminous Coal	1.12	5.60	BASE
Compliance Bituminous Coal	1.12	0.86	BASE
Cofired Powder River & Natural Gas	0.79	0.69	300

Acid Rain Technology Effectiveness (SO^2)

Cofired(1) vs. Noncompliance	11 $ ton
Cofired(1) vs. Compliance	<0 $/ton
Noncompliance w/scrubber(2)(3) vs. Compliance	417 $/ton

Acid Rain Technology Effectiveness (NO^x)

Cofired(1) vs. Compliance	<0 $/ton
Cofired(1) vs. Noncompliance	158 $/ton

(1) $18,000,000 Investment costs for boiler modification for Powder River Coal to be fired at 85% and 100% (MCR) load.

(2) 200 $/KW for scrubber investment.

(3) Parasitic power ~2%.

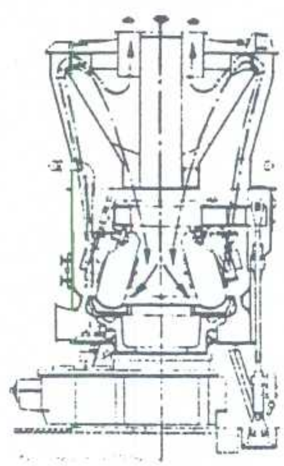
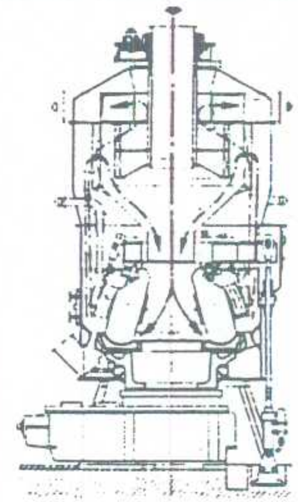
(4) NO_x levels are above Phase 1 compliance.

NO$_x$ PREDICTIONS					
Case	Boiler Configuration	Fuel	Steam Flow PPH	NO$_x$ Emissions	
				PPM @ 3% O_2	lb/10^6 Btu
I	Orig. Boiler Design	Orig. Coal (Bituminous)	1,500,000	820	1.12
II	Orig. Boiler Design	Powder River Coal[1]	832,370	555	.76
III	Rev. Boiler Design	Powder River Coal	1,200,000	585	.80
IV	Rev. Boiler Design	80% Powder River Coal 20% Nat. Gas	1,500,000	580	.79
V	Rev. Boiler Design CCV[2] Burners Only	Powder River Coal	1,200,000	380	.52
VI	Rev. Boiler Design CCV Burners Only	80% Powder River Coal 20% Nat. Gas	1,500,000	415	.57
VII	Rev. Boiler Design CCV Burners & OFA SR_B = 0.9	Powder River Coal SLS Classifier	1,200,000	250	.34
VIII	Rev. Boiler Design CCV Burners & OFA SR_B = 0.9	Powder River Coal SLS Classifier	1,500,000	273	.37
IX	Rev. Boiler Design & Reburning SR_B = 0.9	80% Powder River Coal 20% Nat. Gas	1,200,000	220	.30
X	Rev. Boiler Design & Reburning SR_B = 0.9	80% Powder River Coal 20% Nat. Gas	1,500,000	250	.34

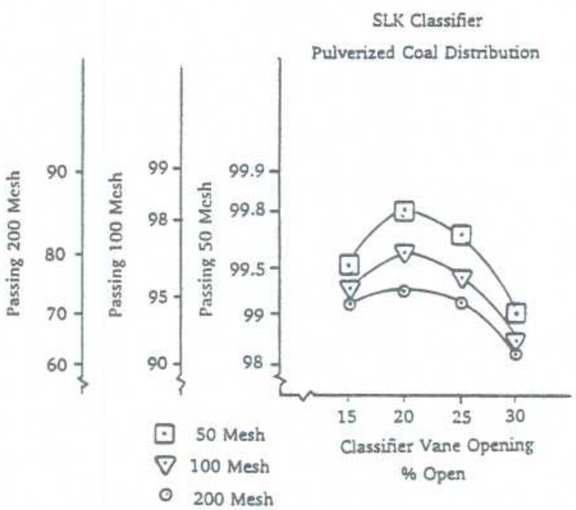
(1) Sub-bituminous Coal: Moist. 30.79; V.M. 30.19; F.C. 33.59; Ash 5.43; 8115 Btu/lb
C 68.64; O 17.15; S 0.50; N 0.77; H 5.10

(2) CCV® Burners are Riley's Controlled Combustion Venturi Low NO$_x$ Burners.

<u>Table 8</u> NOx Predictions

Types of classifiers			
Titles of classifiers		Vane type static classifier / SLK	Slat type classifier / SLS
Comparison criteria: Raw coal throughput *)	%	100	100
Grinding fineness			
R 0,09 mm	%	16	8
R 0,2 mm	%	1,2	0,1
Δp stat. mill + classifier	%	100	115
Mill power	%	100	100
Classifier power	%	-	100
Classifier speed	%	-	130
Classifier temperature	°C	≤90	90
Classifier height	%	100	100 + x
Classifier weight	%	<100	115
Coarse particle return	-	central	central

*) Calculated mill load under consideration of: Hardgrove grindability index, grinding fineness and raw coal moisture



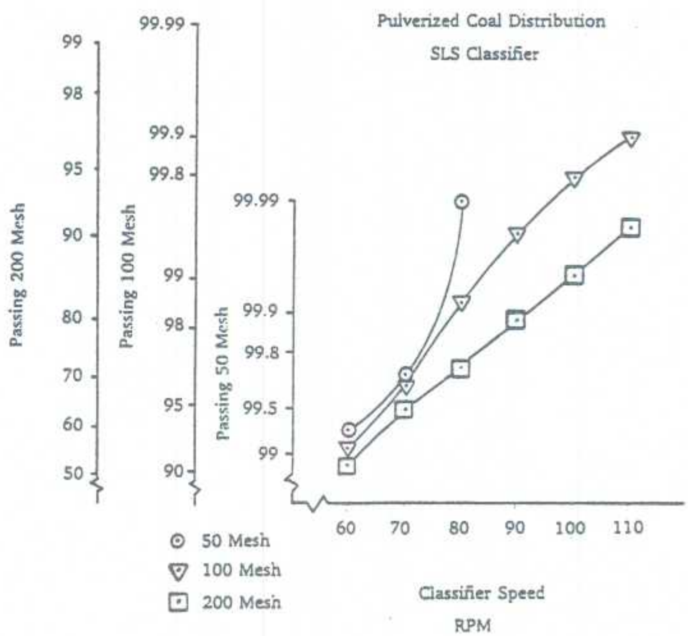


Figure 5 Comparative Classifier Fineness Characteristics

Figure 6A
Gas Reburn Configuration

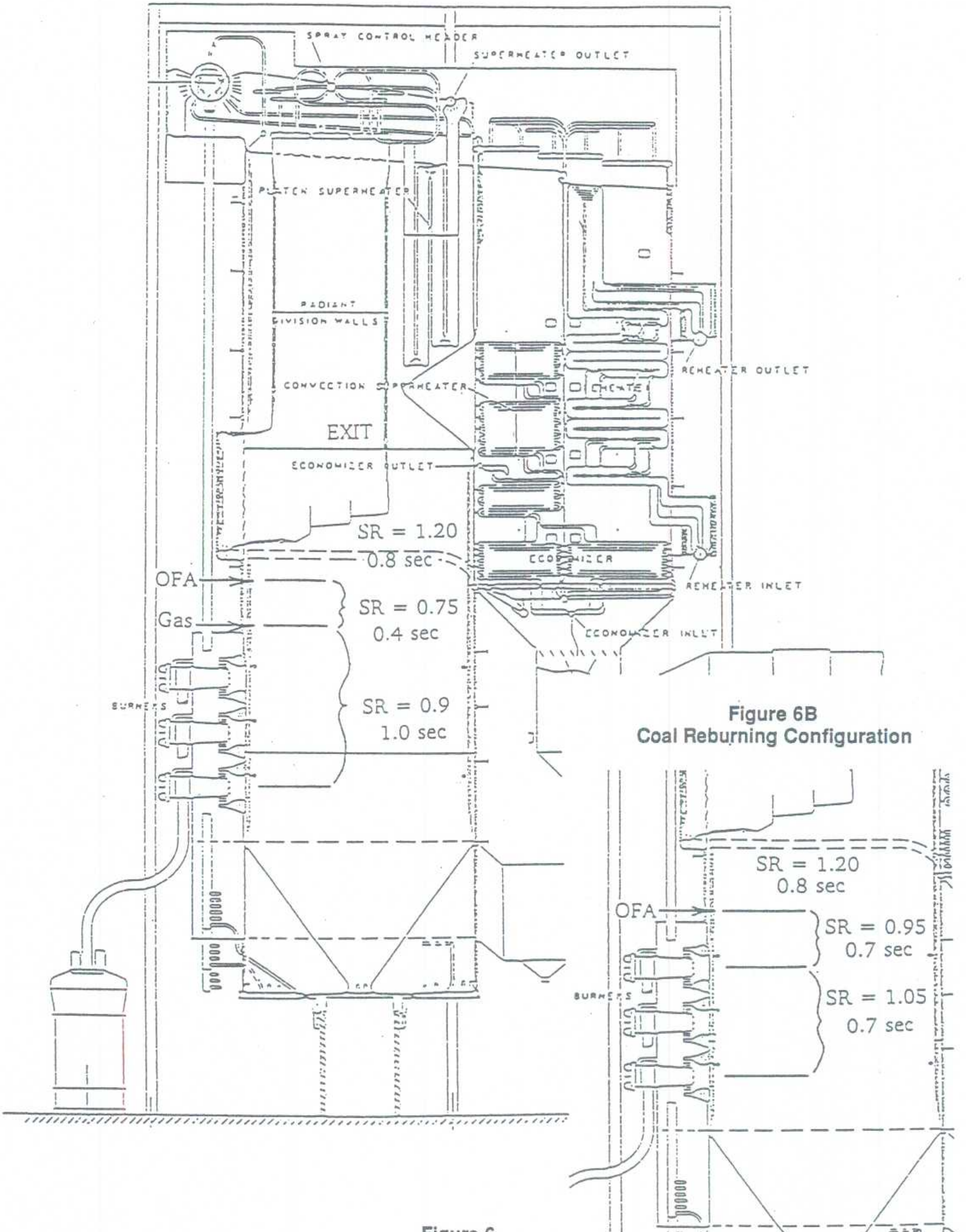


Figure 6B
Coal Reburning Configuration

Figure 6

APPENDIX A

Economics of Alternate Fuels

Item	Symbol	Units	
Capacity Factor	(CF)	%	42.8
Discount Rate	(i)	%	10
Escalation Rate	(e)	%	5
Economic Life	(n)	years	10
Initial Investment Costs (@n=0)	(I)	$200 $/KW	45,000,000
End of 1st Year OM&R Cost Differential (n=1 thru end) (Including Delta Fuel Cost)	(OM&R)	$/yr	-2,279,000
Demand Charge (Dmd.Chrg.)		$/KWe	1500
Energy Charge (Enrg.Chrg.)		$/KWe	0.08
NO_x/SO_x[1] Removed from Uncontrolled Levels		#/MMBTU	5.04
Aux. Power Requirements Unit MCR Fuel Input		KWe	4500
Capital Recovery Factor	(CRF)	0.162745	
Levelized Fixed Charge Rate	(LFCR)	0.177745	
Present Worth Escalating Series	(PWES)	7.439812	
Levelized Capital Costs	(C)	$/yr	7,998,543
Levelized Demand Charge for Aux. Power	(D)	$/yr	1,199,781
Levelized Energy Charge for Aux. Power	(E)	$/yr	1,634,260
Levelized OM&R Costs	(O)	$/yr	-2,759,402
Total Annual Levelized Cost	(T)	$/yr	8,073,182

For the Alternative

Item	Symbol	Units	
Annual Emissions Removed from Uncontrolled Levels	(Y)	tons/yr	19,369
Acid Rain Technology Effectiveness	(ARTE)	\$/ton	417

(1) Represents 90% SO_2 reduction.