1 of 2

CONCEPT SELECTION REPORT

**ENGINEERING DEVELOPMENT
OF ADVANCED COAL-FIRED
LOW EMISSION BOILER SYSTEMS**

U.S. Department of Energy

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TOPICAL REPORT

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EXECUTIVE SUMMARY

Riley Stoker Corporation is leading one of three teams in an R&D program for the expedited development of a new generation of pulverized coal-fired boiler systems. The overall objective is to develop relatively near term technologies to produce Low-Emission coal-fired Boiler Systems (LEBS) ready for full scale commercial generating plants by the end of the decade.

The specific goal of this team is to develop a LEBS incorporating an advanced slagging system for improved ash management in addition to meeting the emission and performance goals. The Riley project team consists of the following organizations: Riley Stoker/Deutsche-Babcock, Research Cottrell Companies, Textron Defense Systems, Sargent & Lundy Engineers, Reaction Engineering International, and Tecogen.

This Concept Selection Report documents an evaluation of subsystems and LEBS concepts. Priority was given to the evaluation of the boiler system, steam cycle, and advanced slagging combustor. Some findings are as follows:

- An ultra supercritical steam cycle is required to meet project efficiency goals. The cost of electricity (COE) for this cycle, at today's fuel prices, and without externality costs, is slightly higher than a conventional subcritical cycle. The supercritical cycle includes a substantial contingency. Reduction of contingency, escalation of fuel cost, or inclusion of externalities all lead to a lower COE for the supercritical cycle compared to the subcritical cycle. The advanced cycle is selected for inclusion in the LEBS.
- The advanced slagging combustor (TVC), should it meet the projected performance goals, yields a lower COE than either a dry firing system or a more conventional slagger fitted with post combustion NO_x controls. Verification and development of the advanced slagger performance is the primary focus of this project.
- A commercial slagging configuration known as U-firing is selected for parallel development and as a platform for adaptation to the TVC.

- A low-temperature heat recovery concept has been identified which should allow a cost effective increase in plant efficiency of about one percentage point compared to conventional design. In combination with the supercritical cycle, this concept approaches the project goal of 42% efficiency.
- While a specific emissions control concept has not been selected, an evaluation of available technologies indicates that several regenerable technologies may be cost competitive with conventional scrubbing. A priority has been set to identify the process which best fits not only the emissions control and waste reduction project goals, but also integrates well with the heat recovery and efficiency requirements of the LEBS.

Section 1

INTRODUCTION

This document is the Concept Selection Report (CSR) delivered under Task 2 of "Engineering Development of Coal-Fired Low-Emission Boiler Systems". Under Task 2, Concept Development, alternative boiler system concepts have been developed which have the potential of achieving the goals of the project, namely dramatically improved environmental performance of electric power generating plants fired with pulverized coal. The purpose of this report is to identify and describe the Low Emission Boiler System (LEBS) concepts identified under Task 2, and selected for in-depth engineering analyses in subsequent phases of the project.

1.1 PERFORMANCE GOALS

The primary performance goals are all emissions-related: NO_x , less than 0.2 lbs/million Btu; SO_2 , less than 0.2 lbs SO_2 /million Btu for coal sulfur less than 3 lbs S/million Btu, or 96.7% control for higher sulfur coals; particulates, less than 0.015 lbs/million Btu.

These emissions goals correspond to one-third to one-half of current Federal NSPS limits. However, not only will NSPS be substantially lowered, but guarantees demanded of manufacturers even now are often well below these limits. Guarantees are being driven by local and state requirements. Any new plant design will need to include the flexibility to meet lower emission limits.

Secondary objectives include improved ash disposability, reduced waste generation, and increased efficiency. Efficiency must remain at least as high as modern conventional plants designed to meet NSPS, and the original program goal for plant efficiency was set at a minimum of 38% (based on HHV). Significantly higher efficiency is now considered essential to maintain the place of pulverized coal-fired generation as a viable alternative for new capacity. Higher efficiency directly reduces resource

consumption and emissions per unit of delivered power. Currently we project the LEBS efficiency to be in the range of 41% with advanced heat recovery techniques, and a challenging goal of 42% has been set for the program.

1.2 SLAGGING COMBUSTION

One specific goal unique to this team is to develop a LEBS incorporating an advanced slagging system capable of meeting all emission and performance goals. Granulated slag from slagging, or "wet" firing systems is lower in volume, and is more stable from the standpoint of leachability than fly ash. Although ash can be used in the manufacture of construction materials, slag is more broadly usable as a byproduct. One Eastern utility reports paying for disposal of ash but selling slag, with a differential cost of over \$20/ton. Disposal and byproduct options are highly site-specific, however, disposal is very likely to become both more restrictive and more expensive in the coming years.

Slagging systems typically exhibit high NO_x emissions and have had historically higher maintenance costs and lower availability. Due to NO_x emissions, few wet firing systems have been constructed since the 1970's. However, many advances have been made in materials for slagging combustors, and good availability is now possible.

Preliminary testing of a Toroidal Vortex Combustor (TVC) being developed by Textron Defense Systems has shown that it offers a number of potential advantages as a low emission boiler firing system. Key among these are excellent combustion stability and high carbon conversion with a wide range of fuels, effective NO_x control with staged combustion, and efficient slag removal. Reduced ash loadings to the furnace are also expected to improve system economics through a reduction in furnace size and tube spacing.

Advances in combustion NO_x control have also been made for commercial slagging systems, but the controlled NO_x is still high relative to the program goals. One alternative system to be investigated under this program is a commercial slagging design, with development efforts focused on further combustion NO_x control, and economic evaluation of post-combustion NO_x control.

1.3 CONCEPT EVALUATION STRATEGY

Advanced slagging systems have many potential advantages, but are also the subsystem requiring the most development to meet the project goals and schedule. Therefore, the firing subsystem analysis was emphasized in concept development. System requirements (eg, higher auxiliary power) were evaluated against expected performance benefits (eg, smaller furnace) to determine if the additional costs can be justified. The performance specifications of the advanced slagging design are estimates which must be demonstrated in this program; however, this process showed that if the performance goals can be met, there is a significant economic benefit. Significant effort was devoted to evaluation of the steam cycle as well. Boiler design, steam cycle, plant efficiency, and firing system selection are all intimately related.

Post combustion emission controls and back end heat recovery, while equally important, can be evaluated to a large extent independently of the firing system. This report includes the results of a survey of emission control systems and a more limited evaluation of back end heat recovery. However, the detailed evaluation comparing various steam cycle, firing system, and NO_x control systems incorporated the same, generic, assumptions for cost and performance of sulfur oxide and particulate control, and low temperature heat recovery.

This report also includes the selection of the design and alternate coals.

Section 2

COAL SELECTION

This section discusses the selection of coal for the design of a low emission boiler system (LEBS). The coal for which the LEBS is to be developed must meet two sets of criteria. The first set of criteria was established by the Department of Energy (DOE) to ensure that the coal selected for testing was representative of a significant amount of United States coal reserves. The second set of criteria has been set by the TVC requirements of a coal with acceptable slagging properties.

Several coal combustion technologies will be evaluated for the LEBS, including slagging technologies such as the Toroidal Vortex Combustor (TVC), and advanced dry-fired low NO_x burners. Of the combustion system options to be pursued in the concept development, the TVC will require the most development work, including testing and modeling.

The dry-fired combustion system will be less sensitive to the slagging properties of the coal, and thus a coal deemed appropriate for the TVC will be appropriate for the dry-fired system. A "design" coal, to be used in the TVC testing and unit conceptual design, and two alternate "test" coals have been selected in order to evaluate the sensitivity of plant performance to coal type. System sensitivity to coal type is an important consideration. Efficiency, cost and availability of alternate technologies are all very dependent on fuel.

The following sections discuss the selection process for the design and alternate coals, and the effects of the properties of these coals on unit performance:

2.1 DESIGN COAL SELECTION

The DOE has set the following requirements for the design coal selection:

1. Current production is extensive, and remaining minable and uncommitted reserves are significant .

2. The sulfur content of the design coal is at least three pounds of sulfur per million Btu.
3. The ash content and characteristics are broadly representative of major reserves of U.S. coals.
4. Adequate quantities of relatively uniform grade can be obtained in support of engineering development and long-term testing in the proof-of-concept facility.

In order to meet the first and second requirements, a high sulfur coal with significant reserves was required. Coals meeting these requirements are found mainly in the bituminous coal seams of Appalachia and the Midwest. Of the two regions, the Midwest not only contains the larger bituminous coal base, but most of this coal is of greater than 3% sulfur by weight, as shown in Figure 2.1. The DOE requirement of 3 lb/MBtu sulfur is very high for Appalachian coals and would require selection of specific seams with rather limited reserves.

Total reserves of significant coals are shown in Figure 2.2. Seam names are shown for convenience; the reserve estimates include other seams within the type, as follows:

<u>Coal</u>	<u>Reserve Estimate Assumption(s)</u>
Illinois No.6	Reserve estimate includes all high sulfur coal adjacent to the Illinois basin. Low and medium sulfur coals are not included. Illinois No. 6 is the most abundant of all the high sulfur Midwestern coals.
Pittsburgh No. 8	Reserve estimate includes all Appalachian medium sulfur, high volatile bituminous coals.
Appalachian High Sulfur	Reserve estimate includes all Appalachian high sulfur, high volatile bituminous coals.
Wyoming sub bituminous	Reserve estimate includes Wyoming reserves only. Although reserves of sub bituminous coal in Montana have been estimated to be extremely large, there has been less development of these reserves and thus there is little data available.
Texas Lignite	Reserve estimate includes Texas reserves only since the Texas lignite seam is isolated from other lignite seams.
Western bituminous	Reserve estimate includes major western bituminous reserves. The analysis presented is for a Wasatch Plateau (Utah) coal.

Figure 2.1 - U.S. Coal Reserves

Source: President's Commission on Coal

Estimated U.S. Coal Reserves

Figure 2.2 - Estimated U.S. Coal Reserves

Based on these assumptions all of the candidate coals selected are widely available and representative of the U.S. coal reserves.

Illinois Number 6 Seam coal has significant reserves with very high sulfur content. The reserves indicated in Figure 2.2 include all Midwest high sulfur coal, of which Illinois No. 6 is a majority.

The Electric Power Research Institute (EPRI) includes an Illinois high sulfur coal in its Technical Assessment Guide (TAG - EPRI Publication P-6587-L). In fact, EPRI TAG specifies the use of the Illinois No. 6 coal for a plant in Illinois or Wisconsin as a base design case. (As of this writing, the TAG reference coal is to be changed to a lower sulfur coal, but this does not effect the selection of the high sulfur LEBS design coal.) Many economic and technical studies have been performed using Illinois No. 6 fuel as a basis.

A specific coal source was selected to serve as the design coal, rather than using a "typical" seam analysis. This is appropriate since experimental testing is to be conducted in Phases I and II, and since a specific sources allows a fully consistent analysis to be developed for the CGU design. The disadvantages of selecting a specific source is that, given the nature of the coal resource, the coal composition is not fixed; given the realities of the coal business, long term availability of a particular source cannot be guaranteed. The source selected, however, is generally representative of the seam, and substitution of another source of the same seam would not significantly affect the design or test program.

The coal analysis selected for LEBS design was obtained from the Monterey Coal Company of Clinton County, Illinois, and is shown in Table 2-1. Data from the Keystone Manual show that the properties of Illinois No. 6 can vary significantly, and that the selected source is representative within the range. The sulfur content is in compliance with the DOE guidelines at 3.15 lb S/MBtu. The ash content of Illinois No. 6 coal is quite variable. However, it is representative of bituminous coal ash in composition, thus meeting the DOE's third requirement. The fact that the coal analysis was obtained from an operating mine supports the last DOE requirement that sufficient quantities of the coal be available for development and testing.

Table 2-1
LEBS Design Coal Analysis

Proximate Analysis Wt%	Monterey Mine Average	Illinois No. 6 Keystone Manual Range
Moisture	15.5	8-20
Volatile Matter	34.0	31-40
Fixed Carbon	42.5	35-44
Ash	8.0	7-13
Gross, Heating Value, Btu/lb	10,800	9,700-11,400
Grindability, hardgrove	56.0	--
Ultimate Analysis, wt%		
Moisture	15.50	8-20
Carbon	59.15	--
Hydrogen	4.23	--
Nitrogen	1.00	--
Chlorine	0.10	--
Sulfur	3.40	1-5
Oxygen	8.66	--
Ash	8.00	7-13
Sulfur Forms, wt%		
Pyretic	1.00	--
Organic	2.37	--
Sulfate	0.03	--
Ash Fusion °F	Reducing	Oxidizing
Initial Deformation	2,040	2,370
Softening (H=W)	2,100	2,430
Fluid	2,340	2,560
1,900-2,650		
Ash Analysis, wt%		
Silica, SiO ₂	49.5	--
Ferric Oxide Fe ₂ O ₃	16.6	--
Alumina Al ₂ O ₃	21.1	--
Titanic Oxide, TiO ₂	1.0	--
Calcium Oxide, CaO	3.7	--
Magnesia, MgO	1.0	--
Sulfur Trioxide, SO ₃	2.2	--
Potassium Oxide, K ₂ O	2.3	--
Sodium Oxide, Na ₂ O	1.6	--
Phosphorous Pentoxide, P ₂ O ₅	0.2	--
Undetermined	0.8	--

The analysis represents a mine-mouth washed coal, as typically supplied by this mine to utility customers. Since mine-run Illinois No. 6 coal can contain as much as 20 to 30% total ash by weight, mine-mouth coal washing is commonly utilized to improve the quality of such coals. In fact, it has been estimated that 58% of all of the coal produced in the United States in 1988 underwent a cleaning process before delivery. Most cleaning processes in commercial use actually reduce fuel costs by reducing the raw coal requirements for a unit. Economic justifications for coal-cleaning include reduction of transportation costs, plant equipment costs and ash disposal costs. The Monterey Illinois No. 6 coal can be considered a beneficiated coal which is cost competitive.

A sample of the coal was obtained from the Monterey Coal Company and analyzed in-house. The results are given in Table 2-2. The composition is very close in all respects to the typical analysis supplied by the mine. Sulfur was about 10% lower at 2.81 lb S/MBtu, slightly below the minimum requirement of 3.0 lb S/MBtu. The mine's analysis will be assumed to be more representative, and will be used for design.

Table 2-2 also lists the results of analysis for chlorine, arsenic, and mercury. Chlorine is an important factor in scrubber design, and may also be a factor in control device requirements if hydrochloric acid emissions need to be controlled. Arsenic and mercury are both important from an emissions standpoint, and arsenic may affect NO_x reduction catalysts. While a single analysis for these compounds is not conclusive, the results indicate that arsenic and mercury for this coal are in the lower range of bituminous coals^{9,10}.

2.2 SELECTION OF ALTERNATE COALS

The two alternate test coals proposed are: 1) a medium sulfur Appalachian bituminous (Pittsburgh No. 8) coal; and 2) a Western sub bituminous coal.

The alternate test coals must meet all of the DOE-established criteria for the design coal except the sulfur content requirement of 3 lb/MMBtu. The alternate coals must meet the requirements concerning availability and broad representation of reserves. Thus, candidate alternate coals were selected from the major coal regions of the United States other than the Illinois basin. The candidate coals include a medium sulfur Appalachian (Pittsburgh No. 8), Appalachian high sulfur, Texas lignite, Wyoming sub bituminous and a western bituminous. Complete coal analyses are presented in Table 2-3. As shown in Figure 2.2, all of the coals have significant reserves available.

Table 2-2

Design Coal Sample Analysis

	<u>As-Rcvd</u>	<u>Dry</u>
Proximate, %		
moisture	14.0	
volatile	34.1	39.7
ash	8.3	9.6
fixed carbon	<u>43.6</u>	<u>50.7</u>
total	100	100
HHV, Btu/lb	10,729	12,476
Ultimate, %		
moisture	14.0	
carbon	60.11	69.90
hydrogen	4.13	4.80
nitrogen	0.85	0.99
oxygen	9.55	11.10
sulfur	3.01	3.50
ash	8.26	9.60
chlorine	<u>0.09</u>	<u>0.11</u>
total	100	100
arsenic, ug/g	2.4	
mercury, ug/g	0.09	

RSC Sample No. 43,992

Sample of washed Illinois No. 6 coal supplied by
Monterey Coal Co. of Clinton County, Illinois

TABLE 2-3
Analysis of Candidate Test Coals

		Design/Test	Test		Test		
		Illinois No. 6 (High Sulfur Central Bituminous)	Pittsburgh No. 8 (Appalachian Medium Sulfur Bituminous)	Appalachian High Sulfur	Wyoming Sub- bituminous - Rochelle -	Texas Lignite (South Central)	Wasatch Plateau (Western Bituminous)
FUEL (NAME):							
Coal Reserves	million tons	64,807	44,170	23,831	65,227	13,480	24,741
Ultimate Analysis							
Carbon	%	59.2	73.8	62.9	50.2	40.6	64.2
Sulfur	%	3.4	2.1	3.3	0.2	1.0	0.6
Oxygen	%	8.7	5.4	6.7	13.6	13.1	11.0
Hydrogen	%	4.2	4.9	4.3	3.4	3.1	4.6
Nitrogen	%	1.0	1.4	1.3	0.7	0.7	1.2
Chlorine	%	0.1	0.1	0.1	0.0	0.0	0.0
Ash	%	8.0	7.2	11.0	4.5	9.3	10.9
Moisture	%	15.5	5.1	10.4	27.4	32.2	7.5
Gross heating value	Btu/lb	10,800	12,720	11,376	8,800	6,825	11,240
Hardgrove grindability	HGI	53	56	57	52	50	44
Ash Fusion Temperature Soft Red.	°F	2,100	2,390	2,240	2,190	2,130	2,250
Ash Fusion Temperature Fluid Red.	°F	2,340	2,560	2,350	2,230	2,190	
Ash Analysis							
Silica	%	49.5	48.7	45.5	33.5	46.5	53.5
Ferric oxide	%	16.6	16.1	23.4	4.9	10.8	4.5
Alumina	%	21.1	22.3	19.5	17.2	23.0	17.3
Titanic oxide	%	1.0	4.1	0.9	1.2	1.3	0.7
Calcium oxide	%	3.7	2.6	3.6	21.3	11.5	10.7
Magnesia	%	1.0	0.6	0.9	6.7	3.2	2.4
Sulfur trioxide	%	2.2	2.5	2.3	11.0	1.7	7.0
Potassium oxide	%	2.3	1.4	2.4	0.3	0.3	1.1
Sodium oxide	%	1.6	1.6	0.4	1.8	0.1	1.5
Phosphorous pentoxide	%	2.0	0.2	0.2	1.2	0.1	0.3
Undetermined	%	1.8	0.0	0.9	0.9	1.6	1.0

Since the reason for choosing alternate coals is to show the applicability of the LEBS to various coal types, these alternate coals should be significantly different from each other and the design coal.

The medium sulfur Appalachian bituminous coal represents a majority of Appalachian coals, and a very large reserve. The western sub bituminous would provide another good reference for the LEBS performance. It represents a very large reserve, and features significantly different properties than the design coal.

Figure 2.3 compares the ash fusion temperatures of the design coal and the candidate alternate coals under reducing conditions. As shown, the temperatures vary widely for the different fuels. All of the fuel types shown have been run successfully in short-term tests in the TVC, so slag properties are not expected to limit TVC operation. For this reason, the Phase I tests will be limited to the design Illinois No. 6 coal.

However, slag properties are a key issue for slagging combustor design, and verifying operability and design for different slag types will be critical as the scale up issues are explored in Phase II. The Pittsburgh No. 8, while a bituminous coal and nominally similar in ash composition to the design coal, has a significantly higher ash fusion temperature. The Wyoming sub bituminous ash also has a higher fusion temperature than the design coal, however, in contrast to the Pittsburgh No. 8, differs greatly in composition. Ash properties, in addition to affecting slag flow, may also affect the amount of ash vaporized in the combustor, retention of toxins, tube metal corrosion or refractory attack. Selection of very different alternate coals will permit these issues to be evaluated.

As will be discussed in Section 3, coal specification can have significant impacts on plant efficiency through the effects on both boiler efficiency and auxiliary power requirements. The proposed alternate coals yield net plant efficiencies both higher (Pittsburgh No. 8) and lower (Wyoming sub bituminous) than the design coal. Table 2-4 shows estimates of boiler efficiencies, auxiliary power requirements, and net efficiencies of an advanced-cycle plant fired with the candidate coals. Figure 2.4 illustrates the effect of fuel type on net plant heat rates for a fixed steam cycle selection.

Finally, as mentioned in Section 2.1, the EPRI TAG base case coal is being changed from the Illinois No. 6, high sulfur coal to a lower sulfur coal. The new base case coal

Ash Fusion Temperatures for Various Coal Types

Figure 2.3 - Ash Fusion Temperatures - Softening and Fluid under Reducing Conditions

TABLE 2-4
LEBS Performance for Candidate Coals

		Illinois No. 6 (High Sulfur Central Bituminous)	Pittsburgh No. 8 (Appalachian Medium Sulfur Bituminous)	Appalachian High Sulfur	Wyoming Sub- bituminous - Rochelle -	Texas Lignite (South Central)	Wasatch Plateau (Western Bituminous)
FUEL (NAME):							
TECHNOLOGY:							
STEAM CYCLE		4500/1100/ 1100/1100	4500/1100/ 1100/1100	4500/1100/ 1100/1100	4500/1100/ 1100/1100	4500/1100/ 1100/1100	4500/1100/ 1100/1100
STEAM GENERATOR:							
Exit Flue Gas Temperature	°F	264	253	276	259	259	259
Radiation Loss	%	0.20	0.20	0.20	0.20	0.20	0.20
Dry Gas Heat Loss	%	3.871	3.829	4.217	3.698	3.896	3.833
Fuel Moisture Loss	%	1.583	0.437	1.010	3.430	5.197	0.739
Hydrogen in Fuel Loss	%	3.888	3.797	3.801	3.841	4.503	4.057
Air Moisture Heat Loss	%	0.185	0.183	0.202	0.175	0.184	0.183
Carbon Loss	%	0.36	0.36	0.36	0.36	0.36	0.36
Unaccounted Loss	%	0.50	0.50	0.50	0.50	0.50	0.50
Total Boiler Loss	%	10.58	9.30	10.29	12.20	14.84	9.87
Boiler Efficiency	%	89.42	90.70	89.71	87.80	85.16	90.13
PLANT PERFORMANCE:							
Net Plant Output	kW	354,624	355,358	354,723	354,212	350,664	354,697
Net (Steam) Turbine Heat Rate	Btu/kWh	7,083	7,083	7,083	7,083	7,083	7,083
Total Auxiliary Power (%GGO)	%	6.79	6.60	6.76	6.90	7.83	6.77
Net Plant Heat Rate	Btu/kWh	8,499	8,361	8,468	8,665	9,024	8,429
Plant Efficiency	%	40.1%	40.8%	40.3%	39.4%	37.8%	40.5%

Estimated Plant Performance for Various Coal Types

Figure 2.4 . Estimated Performance for Advanced Supercritical Plant Fired with Various Coals

is a medium sulfur Pittsburgh No. 8; the Pittsburgh No. 8 fuel analysis shown in Table 2-3 is the typical analysis developed for the TAG. This selection will allow comparisons to be made more easily with other studies. (Note that as of this writing, the TAG ash analysis was unavailable. The ash composition and fusion temperature data in Table 2-3 is from a similar, but lower sulfur coal in Textron's data base.)

2.3 SUMMARY

Illinois No. 6 coal has been selected for the design coal, and a specific source and analysis have been chosen to provide a basis for design of the LEBS. A medium sulfur Pittsburgh No. 8 bituminous coal and a Wyoming sub bituminous coal have been selected for the alternate coals.

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Section 3

PLANT EFFICIENCY AND UNIT SIZE

3.1 OVERALL PLANT EFFICIENCY

One of the important goals of the LEBS development program is to achieve an overall or net plant efficiency of 42%. The efficiency value corresponds to a net plant heat rate of 8125 Btu/kWh.

The heat rate of a power plant is a function of the steam turbine performance, boiler performance and auxiliary power requirement:

$$\text{NPHR} = \frac{\text{NTHR}}{(\eta_{\text{Boiler}}/100) \times (1 - \text{PAux}/100)}$$

Where,

NPHR = Net plant heat rate (Btu/kWh)
NTHR = Net turbine heat rate (Btu/kWh)
 η_{Boiler} = Boiler Efficiency (%)
PAux = Auxiliary Power (% gross plant output)

Thus, in order to maximize the efficiency of the power plant, each of the variables must be optimized.

3.1.1 Net Turbine Heat Rate

The net turbine heat rate (NTHR) is dependent on three inter-related factors: steam cycle conditions, steam cycle configuration and turbine design specifics. By increasing the pressure and temperature of the steam which enters the steam turbine, more power can be generated at an increased plant efficiency. Also, by optimizing the steam cycle auxiliary equipment to best utilize the available heat, the overall plant efficiency is maximized. However, very advanced steam conditions require the use of advanced

materials and advanced design features for the various components of the plant equipment, thus adding cost both for development and fabrication.

The EPRI has sponsored a significant amount of research in the area of advanced steam conditions over the last decade. Sargent and Lundy (S&L) is currently incorporating the results of this research into state-of-the-art power plant (SOAPP) conceptual designs as the SOAPP Workstation. Currently, the most advanced steam conditions being pursued by EPRI for commercial use are ultracritical: 4500 psia pressure and 1100°F temperature. EPRI has concluded that these steam conditions are achievable for wide commercial application by 2000. More advanced steam conditions would require a significant development effort and cause equipment costs to be uneconomical. These conclusions were documented by EPRI in 1981 and the results are still valid.

In the United States, such advanced cycles were used Philadelphia Electric Company's Eddystone Unit 1 (5000/1200/1050/1050) and at Ohio Power Company's Philo Unit 6 (4500/1150/1050/1050). Although the Philo unit was decommissioned in 1975, the Eddystone unit is still in operation at slightly reduced steam conditions. Recent experience in other countries has contributed to material and design features which were unavailable in the 1950's and 1960's when Philo and Eddystone were commissioned. In Japan, Toshiba designed two 700 MW turbines which have been operating at 4500 psia pressure and 1050°F temperature since 1989 for one unit and 1990 for the other. Even with such advanced plants in operation, further development work is required to increase the design steam temperature by 50°F to 1100°F.

SOAPP is utilizing steam conditions of 4500 psia and 1100°F. The SOAPP steam cycle configuration is double reheat (1100°F/1100°F) with nine feedwater heaters and two topping desuperheaters. This configuration was selected to maximize plant efficiency while minimizing generating costs for a commercial plant by 2000. A heat balance for this cycle is included as Figure 3.1. This configuration provides a NTHR of 7083 Btu/kWh (48.17% net turbine efficiency).

3.1.2 Boiler Efficiency

Boiler efficiency is dependent both on the composition of the fuel and the specific design features of the boiler. The composition of the fuel determines the amount of ash removed from the boiler and the properties of the flue gas. The amount of ash or slag

Figure 3.1 Advanced Supercritical Steam Cycle

removed from the boiler represents a sensible heat loss for the boiler. Thus, the more ash present in the fuel, the higher is this ash heat loss and the lower the boiler efficiency. Similarly, the quantity of flue gas produced by the combustion of fuel will affect the boiler efficiency through a sensible heat loss to the stack. Fuel properties which affect the quantity and quality of flue gas are moisture content and sulfur content. The presence of moisture and sulfur oxides in the flue gas reduces the opportunity to recover heat from the flue gas stream with conventional equipment, since constituents will condense out of the flue gas stream and cause corrosion in the back-end of the boiler if the flue gas temperature is reduced below the acid dewpoint. Also, moisture brought into the boiler by the fuel and combustion air requires heat for evaporation which cannot be recovered without condensation in the back end of the boiler. Other losses include radiation loss from the boiler skin, unburned carbon loss, unaccounted loss which is an industry convention, and calcination loss if limestone is injected into the combustor.

For the LEBS, a high sulfur (>3 lb/MBtu) coal has been specified. Such coals often contain a large amount of ash and limit the boiler exit temperature to avoid the acid dewpoint. An Illinois No. 6 high sulfur coal meeting the requirement of the LEBS will limit the boiler efficiency to a maximum of approximately 90%. The boiler heat losses will be minimized wherever possible. Features of the LEBS which may improve this efficiency are slag heat recovery, low temperature heat recovery (acid dew point reduction by sulfur removal, or use of advanced materials and designs to avoid a dew point limitation), air heater leakage minimization, combustion efficiency optimization, excess air minimization. Such design features may add as much as 1% to the boiler efficiency.

Selection of alternate fuels may change the boiler efficiency significantly. For example, a low sulfur, low ash, high heating value coal could increase boiler efficiency by one to two points, while use of a very high moisture, high ash fuel could cause boiler efficiency to drop as much as several points.

3.1.3 Auxiliary Power

The auxiliary power requirements of a power plant can reduce the plant efficiency by as much as 10%. Equipment and systems which contribute to the auxiliary power requirement of the plant include fans, pumps, fuel handling equipment, ash handling equipment, environmental control equipment, water treatment and plant building

systems such as lighting, heating, ventilation, and air conditioning. For SOAPP, S&L has established a minimum plant auxiliary requirement of 7% of the total plant output for an Illinois No. 6 coal. This figure considers the use of high efficiency fans, pumps and motor drives. Also considered is a highly efficient flue gas de-sulfurization (FGD) system, pulse jet baghouse and a selective catalytic reduction (SCR) system.

The LEBS will be configured differently than the SOAPP boiler and auxiliaries, however, it is expected that the total auxiliary power requirement for LEBS will be comparable to that of SOAPP because of trade-offs to be made between the various systems. For example, a TVC-fired LEBS will incur a significant auxiliary power penalty due to pressure drop in the combustor. However, this may be offset by reduced auxiliary power in other components such as ash handling, or reductions in other operating costs such as SCR. For the LEBS, studies will be conducted which compare the use of steam turbine drives instead of electrical motor drives for major fans and pumps. SOAPP includes one turbine drive for the main boiler feed pump. Also, although fuel handling, water treatment and cooling water systems are outside the conceptual design scope of the plant, the auxiliary power requirement of these systems must be included to provide a realistic evaluation of plant performance.

As with boiler efficiency, the fuel composition has a measurable impact on the auxiliary power requirement of the power plant. Utilizing a lower ash, lower sulfur and lower moisture fuel would reduce the power requirement of the material handling equipment, pulverizers, fans and environmental control equipment.

3.1.4 Net Plant Heat Rate

The 4500/1100/1100/1100 SOAPP cycle yields NTHR of 7083 Btu/kWh. For a boiler efficiency of 90% and an auxiliary power requirement of 7.0% of the total plant output, the overall NPHR would be 8462 Btu/kWhr (40.3% efficient). For fixed values of boiler efficiency and auxiliary power, Table 3-1 shows a comparison of net plant heat rates achieved with three steam cycles: a 2400/1000/1000 subcritical, single reheat; a 3500/1000/1000 single reheat, supercritical; and the 4500/1100/1100/1100 double reheat.

Table 3-1
Plant Efficiency for Three Steam Cycles

Type	Subcritical	Supercritical	Adv. Super Critical
Cycle	2400/1000/SRH*	3500/1000/SRH	4500/1100/DRH**
NTHR	8005	7500	7083
Boiler Eff., %	90	90	90
Aux. Power, %	7	7	7
NPHR, Btu/kWh	9564	8961	8462
Net Plant Eff., %	35.7	38.1	40.3
* single reheat			
** double reheat			

There are many more combinations of pressure, temperature, and reheat, and the NTHR depends on details of the steam cycle design in addition to pressure and temperature. However, the results shown are representative. Only the advanced cycle moves well beyond the 38% minimum efficiency goal with the design coal.

3.2 UNIT SIZE

The original solicitation for this project specified that a commercial generating unit (CGU) design would be developed for a 100 MWe unit. The current Statement of Work specifies that the CGU shall be for a 300-400 MWe unit. This change was based on the fact that many of the advanced technologies required to meet the performance objectives would not be economically viable at the 100 MWe scale, as well as the potential market for base-loaded, coal-fired power plants.

Both Sargent & Lundy and Riley concurred with this change in CGU design basis, and concluded that both the market and economies of scale favor the high end of this range. One important factor in this decision was that while the original SOAPP design was based on 300 MWe, it was changed to 400 MWe on the advice of the 24 member utility advisory committee. Finally, turbine size does not appear to be a limitation for 400 MWe.

3.3 CONCLUSIONS

The LEBS concepts will incorporate the following:

- An advanced, supercritical 4500/1100/1100/1100 steam cycle based on the results of the SOAPP project, and on program goals. Some development work will be required, but this will be limited to engineering analysis and utilization of both internal and external concurrent development results.
- A nominal generating unit net output of 400 MWe. There are no barriers to this size unit, which appears to offer the best economies of scale and market fit.

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Section 4

FIRING SYSTEMS

Our objective in firing system selection and development is to develop an advanced slagging firing system capable of meeting the primary goal of low NO_x emission and the secondary goal of improved ash disposability/byproduct use. However, it is important to at least briefly discuss the status of dry-firing systems for two reasons. First, dry firing of pulverized coal is by far the most prevalent technology today for large scale power generation from coal, and is the system against which the economics and performance of alternate technologies must be compared. Secondly, combustion NO_x control with dry firing has advanced to the point that systems meeting the program NO_x goal of 0.2 lbs/MBtu without post combustion control are or will be commercially available; thus, they are a readily available back up should the economics of slagging systems not prove favorable.

4.1 DRY LOW-NO_x FIRING

Riley supplies a single-register, low NO_x burner known as the CCV (Controlled Combustion Venturi). Within the next two years Riley Stoker will have nearly 5000 MWe of installed CCV burner capacity and over 450 burners in operation. Most of this capacity will be retrofit to existing units to meet Clean Air Act requirements, typically 0.45 lb/MBtu. Two boilers retrofit recently successfully met these levels. A 100 MWe equivalent boiler met the guarantee level at a burner stoichiometry above 1.0. Operation above 1.0 stoichiometry is strongly preferred for retrofits, due to restrictions on burner placement and air ducting compared to new designs. However, tests were conducted down to a burner stoichiometry of 0.9 on this unit, with NO_x levels as low as 0.25 to 0.3 lb/MBtu. These burners incorporated the latest design enhancements developed in testing at Riley Research last year.

Designs for new units are also in active development. Guarantees required for bids on new units are running typically at about 0.3 lb/MBtu from the boiler, with many requiring post combustion control or at least a design allowing later installation of additional

controls. Construction is now in progress on a 700,000 lb/hr steam industrial boiler (roughly equivalent to 100 MWe) with a guarantee of 0.3 lbs/MBtu NO_x.

Figure 4.1 shows the results of operation of a dual-register burner design, known as the DS burner, at 200 MWe plant in Germany. This burner gave a NO_x value of 0.2 lb/MBtu at a burner zone stoichiometry of 0.9. The boiler is normally operated at a burner zone stoichiometry of 0.95. Although these results were with a high volatile German coal, recent tests of this burner at the Riley test furnace confirmed its low-NO_x performance on a range of US coals. Furthermore, in the most recent tests at the Riley test facility, certain components of the DS burner were replaced with components based on the CCV burner design. This hybrid configuration exhibited lower NO_x and improved flame characteristics, and is a promising development.

In summary, Riley expects to have a commercial dry-firing option able to meet the NO_x goals of this program, well within the required time frame, and without significant outside development support.

4.2 SLAGGING COMBUSTION SYSTEMS

A number of different firing configurations designed for removal of coal ash as slag are in operation. Cyclone firing is the most common type, however, there are also wet-bottom tangential, wall, arch, and roof-fired systems. Slag-tap combustion systems are capable of firing a wide range of fuel types, and are particularly well suited to poor quality coals having high ash content with low fusion temperature.

Granulated slag from slagging, or "wet" firing systems is about one-third the volume of fly ash, and is lower in leachability than fly ash. Although disposal and byproduct options are highly site-specific, granulated slag finds a larger market for byproduct use, whereas flyash has more limited markets and in many cases must be landfilled. Byproduct utilization and disposal characteristics will increase in importance as environmental regulations become stricter.

Despite the favorable attributes of slag-tap systems, few have been constructed since the 1970's, primarily due to the high NO_x emissions characteristic of slagging combustion. Reliability and maintenance costs have also been of concern. However, many advances have been made in materials and good reliability is now possible.

DS BURNER FIELD TEST RESULTS

Figure 4.1 Field Test Results from Riley/DB
Advanced Low-NOx Coal Burner

The high combustion temperatures required to insure slag flow in conventional wet bottom furnaces produce relatively high NO_x emissions. Currently operating wet bottom boiler systems were installed prior to NO_x emission limitations established by the New Source Performance Standards. However, today's emission regulations pose a serious challenge for both new and existing wet bottom boiler systems. Various retrofit combustion NO_x control technologies have been applied in the U.S. and Europe to reduce NO_x emissions from wet bottom boilers. The level of NO_x reductions achieved are summarized as follows for different slag-tap firing configurations.

4.2.1 Cyclone Firing

The cyclone firing system represents a significant portion of the U.S. slag-tap boiler population. Retrofit combustion NO_x control technologies which have been applied to U.S. cyclone boilers have included coal reburning, natural gas reburning and limited air staging experience. NO_x reductions of 50% have been demonstrated with 18% of heat input from natural gas¹. The cost of NO_x reduction is primarily dependent on gas to coal price differential.

Coal reburning is another fuel staging technology which can be applied to reduce NO_x emissions from plants where natural gas is unavailable or too costly. Finely pulverized coal is injected above the primary combustor zone to create the required reducing conditions. Retrofit requirements include an advanced mill/classifier to insure sufficient burnout in the residence time available. NO_x reductions of 55% have been demonstrated with an increase in carbon loss of 3.5% of heat input².

Air staging is a proven method for reducing NO_x emissions, however there is very little experience with air staging on U.S. cyclone fired units. The history of corrosion problems and the lack of regulatory incentive restricted the development of this technology in the U.S.

In Germany the first cyclone boiler was converted to operation using a staged combustion air design in 1984³. Since then over 20 cyclone fired boilers have been converted to operate under staged combustion conditions with no adverse operating or maintenance problems. The air staging arrangement used is shown in Figure 4.2. The stoichiometry of the primary cyclone chamber is reduced to as low as 0.8 and the remaining tertiary air is injected in the secondary combustion chamber. Optimum location for tertiary air injection varies slightly from plant to plant and is determined by

AIR STAGING SYSTEM FOR DB CYCLONE BOILERS

Figure 4.2 Air Staging System for DB Cyclone Boilers

flow model tests. The NO_x reductions achieved for two German plants are shown in Figure 4.3. As indicated NO_x reductions from 30 to 40% can be achieved by this method.

There are a number of important differences between the European and American cyclone designs which bear on the applicability of air staging to U.S. cyclone fired units. The German units designed by Deutsche Babcock fire a fine grind coal obtained using beater type mills whereas U.S. designs fire coarser crushed coal. The Deutsche Babcock design also locates the primary air and coal injection below the secondary air nozzles as opposed to axial injection through the conical end of the cyclone. In addition, many of the U.S. cyclone units do not have a secondary combustion chamber; air is distributed via a windbox rather than providing individual air flow control for each cyclone.

The DB experience list includes 96 cyclone fired boilers, with the last unit constructed in 1970. The maximum size built was about 230 MWe.

4.2.2 U-Firing

The roof or arch-fired design also represents a significant portion of the slag-tap boiler population. In the U.S. Riley developed wet bottom "Turbo" fired units and Foster Wheeler developed "arch" fired units⁴. In Europe, Deutsche Babcock developed the U-firing system.

The U-fired slag-tap design is well suited to larger capacity boilers and is capable of operating over a broad load range while maintaining flexible fuel requirements. DB has constructed U-fired boilers up to 350 MWe capacity, and the design can be used for even larger capacities. Units have been designed with turndown capability as low as 20%. Design fuels have varied from 10 to 40% volatile, (daf), 5 to 35% ash, 2 to 22% moisture, and 17-32 MJ/kg (7300-14,000 Btu/lb). The experience list includes 49 boilers constructed in Europe through 1982. The design is still actively offered; six U-fired boilers are currently under contract and in design for construction in China.

As with cyclone fired systems, the high temperatures required to maintain slag flow result in high NO_x emissions from conventional designs. As a result of legislation in the 1980's many German U-fired boilers were retrofit to control NO_x emissions. A number of control measures were demonstrated including reburning, flue gas

NO_x REDUCTIONS BY AIR STAGING

Figure 4.3 NO_x Reductions by Air Staging

recirculation via primary or secondary air, and air staging through various tertiary air locations. The tertiary air injection locations used to stage the combustion air addition in U-fired furnaces, are shown in Figure 4.4.

The combustion chamber design for new U-fired slagging systems utilizes three levels of tertiary air injection for maximum NO_x reductions. This staging system design results in a burner stoichiometric ratio of 0.9. Stoichiometry after tertiary air II injection is 1.05, and the final stoichiometry of 1.15 is achieved through addition of tertiary air III after the screen tubes.

The NO_x reductions achieved through different combinations of tertiary air injection and flue gas recirculation are shown in Figure 4.5. The reductions achieved for Plant 1, a 320 MW unit, were accomplished using tertiary air nozzles located in the furnace roof and flue gas recirculation through the secondary air. The reductions for Plant 2, a 300 MW unit, were achieved using tertiary air locations I and II, in the furnace roof and side walls. The flue gas recirculation results for Plant 2 are based on recirculation with the primary air.

NO_x emission reduction levels from 30 to 60% have been achieved from these combustion modifications with no adverse impacts with regard to operational safety, carbon burnout, slag flow and furnace corrosion. In all cases combustion modifications also included addition of rotary classifiers to improve coal fineness and improve distribution of fuel to the burners. These efforts contribute to the minimal impact of staging on carbon burnout.

The major concern of many utilities with regard to staged combustion for NO_x control is the increased potential for corrosion during operation under reducing conditions. In Germany the problems with furnace corrosion were experienced by slag-tap units prior to combustion modifications for NO_x control. These problems were addressed through extensive development work to improve the availability of slag-tap furnaces. The susceptibility of the combustion chamber to corrosion has been significantly reduced through improvements in studding and refractory application technologies. High availabilities have been demonstrated at many units operating under staged and unstaged conditions.

One avenue to be explored in advancing the U-fired design will be the possibility of running the entire slag-tap chamber fuel rich. Preliminary investigations suggest that

AIR STAGING SYSTEM FOR DB U-FIRED BOILERS

Figure 4.4 Air Staging System for DB U-Fired Boilers

NOx REDUCTIONS BY AIR STAGING AND FLUE GAS RECIRCULATION

Figure 4.5 NOx Reductions by Air Staging and Flue Gas Recirculation

there is not a materials barrier to this concept. One concern other than corrosion is maintaining carbon conversion when final combustion air is added at lower temperatures for NO_x control.

4.2.3 Toroidal Vortex Combustor

The fuel flexibility, carbon conversion, and ash management advantages of slagging combustion provide the incentive for developing a slagging system for new applications. The Toroidal Vortex Combustor (TVC) is being developed by Textron for both pressurized and atmospheric application⁵. Preliminary testing of the TVC operated at atmospheric pressure has shown that it offers a number of potential advantages as a LEBS firing system. Key among these are excellent combustion stability and high carbon conversion with a wide range of fuels, effective NO_x control with staged combustion, and efficient slag removal. Reduced ash loadings to the furnace are also expected to improve system economics through a reduction in furnace size and tube spacing.

Figure 4.6 shows a 25 million Btu/hr TVC test unit configured for Phase I testing. Combustion occurs primarily as suspension burning in a fuel rich, highly mixed primary chamber. Slag separation is decoupled from combustion, and is accomplished by jet impaction in a second chamber. Secondary air in the test rig is added in a duct downstream of the slag separator; as part of a LEBS, the fuel rich gases would be directed into the boiler with secondary or staging air to complete combustion.

Several performance and design uncertainties for the TVC are being addressed experimentally in Phase I of the LEBS project. These include pressure drop requirements, scalability (combustion and slag separation), integration with the steam circuit, and economics. Phase II will see the combustor tested at small commercial scale, 100-million Btu/hr. The Proof of Concept facility to be built and tested in Phase IV will require combustors of 150-300 million Btu/hr scale. This will provide the design data for modules up to 400 million Btu/hr in the Commercial Generating Unit (CGU) design.

Assumptions for TVC benefits and costs are given in the economic evaluation of Section 7:

TVC CONCEPT FOR LOW EMISSIONS BOILER

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Figure 4.6 TVC Concept for Low Emissions Boiler

4.3 MILLING SYSTEMS

Low-NOx dry firing is enhanced by advanced mill and classifier designs which not only decrease the average particle size of the coal, but drastically reduce the percentage of large particles. It is these larger particles which contribute most to carbon loss, particularly under low-NOx design conditions. This is true as well of both the U-fired and TVC-fired slagging systems. Therefore, an advanced mill system incorporating dynamic classifiers will be a part of each LEBS concept in this project.

The mill selected for LEBS design is the DB MPS, a vertical spindle type mill, fitted with an SLS rotating classifier. This is the milling system of choice in both new and retrofit application, barring special requirements such as highly abrasive coals (for which ball-tube mill might be favored), or small capacity, frequent start/stop operation (where an attrition mill may be preferred).

Advantages of the MPS include low specific power (important in minimizing overall plant auxiliary power), reliable operation, large capacities, and low floor space requirement. The mill and classifier design allows multiple coal pipes to be taken directly from the classifier, giving better distribution than splitters. This feature is important to maintain close control of air/fuel ratios and burner to burner distribution in low-NOx firing systems.

The advantage of a dynamic, or rotating, classifier is the reduction of oversize coal particles without undue increase in fines generation. Figure 4.7 shows a comparison of particle size distributions (PSD) for static and dynamic classifiers. If both mill/ classifier systems are sized and operated for production of a nominal 70% -200 mesh grind, the fraction of larger particles differs significantly:

	static	dynamic
%-200 mesh	70	70
%-100 mesh	90	96
%-50 mesh	99.0	>99.9

Conversely, the mill with a static classifier would need to be designed for 80% through 200 mesh to match the 100 mesh specification of the dynamic system.

COMPARISON OF STATIC AND DYNAMIC CLASSIFIERS

Figure 4.7 Comparison of Static and Dynamic Classifiers

Increasing the fineness of pulverized coal increases both the direct auxiliary power for the mill/classifier motors, and the pressure drop through the mill (due to higher recirculating load) of the conveying air stream. Estimates of these power penalties are shown in Figures 4.8 and 4.9. These estimates were derived for standard, commercial sized mills with dynamic classifiers, handling the design fuel flow for the 400 MWe, high efficiency plant. The lines showing specific mill power vs percent through 200 mesh terminate at the upper limit of mill capacity.

In Figure 4.10, the total equivalent auxiliary power of the mill, classifier, and pressure drop through the mill is shown for three mill sizes as a function of coal fineness. While every added auxiliary power requirement is important, there does not appear to be a substantial penalty in increasing the fineness from 80 to 85 or even 90% through 200 mesh (will quantify kw and press drop equiv in cents/kwh). The move from 90 to 95% fineness drives the specific power up at a higher rate, and would also require selection of a larger mill than the 85-90% range, or additional mills at higher capital cost.

4.4 CONCLUSIONS

1. The U-fired system will be evaluated as a slagging system with the potential for significant further combustion NO_x control, but probably requiring post combustion control. While the analysis of Section 7 shows that this option may be more costly than either dry firing or advanced slagging combustion NO_x control, the increase is relatively small, and the probability of success with moderate development effort is high.

U-firing is selected for this role based on its suitability for larger units, fuel flexibility, and turndown. In addition, the design appears to be more adaptable as a platform for TVC firing in larger size units; development efforts here will support the TVC commercialization effort as well.

2. The U-fired system will also be developed as a platform for integrating the advanced combustor to a commercial scale boiler, taking advantage of the established commercial design experience, and of the efforts under (1) above.
3. The TVC will be the main focus of the Phase I development efforts, based on the potential advantages cited in this section and on the preliminary economic analysis in Section 7.

**SPECIFIC POWER VS FINENESS
FOR VARIOUS MPS MILL SIZES**

**PRESSURE DROP VS FINENESS
FOR VARIOUS MPS MILL SIZES**

Figure 4.10 Total Auxiliary Power vs. Fineness

4. Dry firing systems are very near commercial status to meet or exceed the NO_x limits of this program. The results of concurrent internal and external development programs for advancement of low-NO_x firing will be actively incorporated into this program, both as a basis of cost comparison, and as a contingency system should problems develop with the slagging systems. However, no significant development efforts in this area are planned at this time within this project.

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Section 5

POST COMBUSTION EMISSION CONTROL

Primary program goals include specific emission limitations for SO₂, NO_x, and particulate. Secondary goals require that the products of emission control processes be non-hazardous and preferably saleable as byproducts. Air toxics emissions are not specified, but will clearly be of increasing importance as regulations become tighter. Each of these issues are addressed in the following sections.

5.1 NO_x CONTROL

The program requirement is control to 0.2 lbs NO_x/MBtu. As discussed in Section 4, our objective is to meet this goal with TVC slagging combustion technology; the 0.2 lb/MBtu level is very nearly commercially available for advanced dry firing technology. One further option to retain the advantages of ash vitrification with less development risks than the TVC is to assume modest improvements to the NO_x emission performance of a commercial slagging system combined with post combustion control. The data discussed in Section 4 suggest that 0.6 lb/MBtu should be achievable with only minor development effort.

The system selected will need to have the capability to meet local permitting requirements which may be significantly lower than program goals. Requests for bids on new units even now include NO_x guarantees as low as 0.1-0.17 lb/MBtu. For this reason, we believe the LEBS must be capable of lower limits, and have chosen 0.1 lb/MBtu as a target for demonstration.

The levels of control (% reduction) required are as follows:

	<u>Inlet</u>	<u>0.2</u>	<u>0.4</u>	<u>0.6</u>
Outlet:				
0.2 (approx. 147 ppm @ 3% O ₂)		0	50	67
0.1 (74 ppm)		50	73	82

The post combustion control required to meet the 0.1 lb/MBtu limit is 50% for the anticipated degree of combustion control on either dry or advanced slagging systems; for the commercial slagging option it could be as high as 83%. Base cost estimates will be made for the program requirement of 0.2 lb/MBtu. This level will require no post combustion control for the advanced slagging system, but will still require SCR to meet 67% control for a commercial slagging option.

Reburning. Reburning can be considered as a combustion modification, and is not discussed here.

SNCR. A review of recent papers on SNCR shows that the maximum practical removals may be limited to 40-50% due primarily to ammonia slip. This was true even under well controlled conditions in a pilot scale test boiler¹. While catalyst costs are avoided, consistent control even at lower levels requires sophisticated control of injection rate and temperature. Other concerns are N₂O emission and fouling due to ammonium bisulfite formation. There may be situations where SNCR would be appropriate for modest reductions, but no development work is anticipated this project.

SCR. SCR is a well-established, commercial technology capable of handling the 50-83+% reduction which might be required under divergent LEBS concepts discussed above. Reagent usage is near-stoichiometric, and ammonia slip can be controlled to very low levels, up to NO_x reduction rates of about 90%. There are no indications that N₂O production is significant. These factors are more consistent with the program goals of minimizing resource usage and waste production. Proper disposal or reuse of catalyst material is an issue, and must be included in cost estimates for the process.

Catalyst and overall system costs have fallen markedly for this technology. Figure 5.1 shows a recent estimate of SCR cost for a new plant. The costs are shown as leveled mills/kWh vs uncontrolled (or combustion process) NO_x level for two final control values, either 0.1 or 0.2 lb NO_x/MBtu. This analysis is not valid at the limits, for example, it does not show zero cost for 0.2 controlled to 0.2. However, it gives a good representation of the effect of combustion NO_x control level on SCR cost, once an SCR system has been assumed to be necessary. It also indicates the added cost for controlling to a final value of 0.1 lb/MBtu compared to 0.2 lb/MBtu.

"High-dust" SCR refers to placement of the catalyst upstream of the particulate and SO₂ control devices rather than absolute dust level. This configuration is more

Cost for SCR versus Uncontrolled NOx Rate

Figure 5.1 Cost for SCR versus Uncontrolled NOx Rate

economical than a "tail-gas" system which requires all of the gas to be reheated to SCR temperatures of 650°F or higher after particulate and SO₂ cleanup. One advantage of a slagging system with high boiler ash retention would be reduced ash erosion of the catalyst in a high dust configuration. Concerns about deactivation due to high SO₂ concentration in the high dust system are being addressed in on-going demonstrations and in development of improved catalysts. This does not appear to be an insurmountable problem, but may increase the process cost through shortened catalyst life.

Catalyst poisoning by arsenic is a concern with a high-dust SCR configuration in conjunction with a high rate of ash recycle in a slagging system². A high rate of ash recycle is required to maintain effective ash vitrification when the once-through ash retention is low. This can lead to an enrichment of arsenic and accelerated catalyst deactivation. Test data indicate that this problem can be eliminated with small amounts of lime addition to the slag chamber. Metal resistant catalysts are also under development.

Hot gas particle cleanup eliminates both flue gas reheat and erosion/ash poisoning concerns. Processes combining ash removal and catalytic NO_x reduction may be cost effective. Two examples are CeraMem's ceramic catalytic filter³ and the EERC/UND catalytic fabric filter work⁴, both being developed under DOE sponsorship. These processes are more developmental than standard SCR applications, but will be evaluated for integration into the LEBS.

5.2 SO₂ CONTROL

The SO₂ control requirements set by the program are an emission rate of 0.2 lb SO₂/MBtu for coal sulfur of less than 3 lb S/MBtu, or 96.7% control for higher sulfur coal. The percentage controls and emission levels for the design and alternate coals are then as follows (% reduction based on coal sulfur, although a small portion of the total coal sulfur may be retained in the ash):

	<u>lb SO₂/MBtu</u>		<u>% reduction</u>
	<u>inlet</u>	<u>outlet</u>	
Illinois No. 6 (design)	6.30	0.21	96.7
Pittsburgh No. 8 (alternate)	3.30	0.20	93.9
Wyoming subbit. (alternate)	0.80	0.20	75.0

For simplicity, the emission limit will be taken as 0.20 lb/MBtu regardless of coal sulfur. As with NO_x emissions, limits are likely to be driven lower in many cases by local permit requirements. For this reason, the LEBS system should have the option to meet a limit of 0.1 lb SO₂/MBtu.

Combustor Sulfur Capture

Preliminary information available at the time the proposal was submitted had indicated that sulfur capture within the TVC might be as high as 90% at limestone stoichiometries of 2 or less, under conditions of continuous slag tapping. While the program requirement of nearly 97% SO₂ control would still require substantial downstream cleanup, there were some potential system advantages with such high levels of control. One scenario involved the recycle of SO₂ adsorbed on the coal feed stream. An evaluation under the HIPPS project indicated that the SO₂ adsorptive capacity of bituminous coal was not adequate to support this concept.

Additional data since generated under conditions of slag tapping has shown SO₂ removal in the combustor of about 50% at a stoichiometry of 3. While limited, this data is consistent with other recent slagging combustor results as well as equilibrium considerations^{5,6}.

Each unit stoichiometry of calcium added corresponds to the following for the design Illinois No. 6 coal:

lbs CaCO ₃ /lb coal	0.11
lbs CaO/lb ash	0.74

The ratio of sorbent to ash is somewhat exaggerated by the relatively low ash content of the design coal, but clearly, calcium stoichiometries of 2 or more are inconsistent with waste minimization objectives, particularly if additional downstream cleanup is required. For this reason, combustor sulfur capture will not be considered in this project.

Downstream Cleanup

There are a great number of options, both commercial and in development, for removal of SO₂ from combustion flue gases. In order to sort through the various technologies, an evaluation was performed in which various objectives are numerically ranked and added to score each technology. This evaluation was patterned after a similar one performed for combined NO_x/SO_x control technologies⁷, the results of which are also incorporated here. In addition, costs have been estimated for promising technologies where sufficient information is available. Findings from the evaluation are discussed below.

Advanced wet FGD is consistent with the high removal efficiency and reagent/waste minimization goals of the project. Compared to other non-regenerable systems, the reagent quantity is minimized at near unit stoichiometry. Forced oxidation systems can produce marketable gypsum; if market conditions do not favor gypsum sale, handling and disposal characteristics are good. Waste water streams can be reduced or in some cases eliminated by evaporating to dryness for disposal with ash. The basic technology is well established and available from many vendors, keeping cost low. Incremental improvements are possible in reduction of auxiliary power, equipment reliability, and materials of construction. Accurate cost and design data is readily available. Advanced FGD designs ranked among the highest in the evaluation, and were the most cost effective at current cost and performance.

Recirculating, semi-dry systems can approach the removal requirement at somewhat higher stoichiometry. However, the economics for a new, base-load plant will be very sensitive to both stoichiometry and reagent cost (ie, lime vs limestone). Rankings for these systems were lower than wet FGD, primarily due to increased reagent and waste quantities. Costs are not complete. These systems are not expected to fit into the LEBS concepts.

Several regenerable systems still in development or demonstration stage ranked highly, and were cost competitive with FGD (or FGD/SCR in the case of a combined SO₂/NO_x process. These will be studied closely, since the use of a regenerable process would eliminate a major waste stream compared to throwaway FGD, and the gypsum market will be sensitive to geography (transportation costs) and number of producers. Critical factors include system complexity, cost, and reliability, as well as the market for byproduct. In comparison to wet FGD, cost, performance, and reliability are all relatively uncertain. Conversely, the economics will become more favorable if the relative difference between gypsum sale or disposal and higher value products increases. As demonstration and development programs progress, better information should be available for evaluating these.

Despite uncertainties in cost and performance, the incorporation of a regenerable system into the LEBS will be given high priority, based on the potential to eliminate a major waste or low-value byproduct stream. In addition, certain regenerable systems offer other advantages such as improved toxics control, for which a cost advantage cannot at present be quantified. Finally, systems which operate dry, but well above the acid dewpoint, may offer significant advantages in integration with a low temperature heat recovery process.

5.3 CONTROL OF PARTICULATE, TOXICS

The program requirement for particulate emission is 0.015 lb/MBtu. This value is expected to satisfy most permit requirements, and a demonstration target of 0.010 lb/MBtu has been selected.

The degree of ash retention in TVC will depend on the economic tradeoff between combustor pressure drop, separator design, and the benefits of reduced ash loading for boiler design and ash disposal, but will have a lesser impact on the downstream control requirement. The design of the particulate control system will be driven more by the need for fine particulate control than the total efficiency. However, reduction of fly ash loading by combustor slag removal can be expected to decrease control device size somewhat, for either an ESP or a fabric filter.

Control of fine particulate is also essential for the reduction of condensable toxics which tend to concentrate on fines. Toxics control is not a specific program goal, but this area will be increasingly important in the next few years. Therefore, it is prudent at

a minimum to design for high-efficiency capture of fine particulate. This is more effective for toxics and acid aerosol if done at the lowest possible temperature in the system. One option which would enhance toxics control for a system using wet gas contacting (either conventional limestone FGD or any one of several wet regenerable systems) is wet electrostatic precipitation. A wet ESP could be used to upgrade or replace mist eliminators in a wet SO₂ scrubber. Wet ESP's are a well established technology for many industrial processes.

Filtration through activated carbon or coke is the most effective toxics control method currently employed on large scale combustion processes such as municipal waste incinerators. The degree of control which might be required on power plants, as opposed to incinerators, is not known at this time, so a stand-alone toxics control system is difficult to evaluate. However, future toxics control requirements may justify the use of SO_x/NO_x control processes which are somewhat more costly but combine both toxics and acid gas control in the same unit.

ESP vs Fabric Filter

A recent analysis of commercially available particulate control technologies⁹ showed that, for the high sulfur (ie, low resistivity) design coal, an ESP would be equivalent in cost to pulse-jet fabric filtration at the level of 0.01 lb/MBtu. The ESP costs increase sharply for a low-resistivity ash, but decrease with higher emission levels; the filter costs were essentially independent of emissions, and decreased somewhat for lower sulfur coals. One issue would be the performance of a fabric filter with the finer particulate expected from TVC firing.

However, the ESP could be very cost effective if used as a relatively low-efficiency collector in a concept incorporating final, high-efficiency control such as a wet ESP following a scrubber. In this case, the efficiency requirement of the primary ESP would be set by ash deposition on downstream low-temperature heat recovery surfaces and in SO₂ removal process, eg, contamination of gypsum product.

5.4 CONCLUSIONS

1. The initial project focus during Phase I is the combustion system selection and development, and integration to the steam cycle. The initial assumption used to cost emission control will be SCR for NO_x, an ESP for particulate, and wet FGD

for SO₂. Performance and cost of each of these components are well documented and can meet the program requirements. Incremental performance advances and cost reductions are expected as a result of a highly competitive market for these maturing technologies.

2. More advanced regenerable and combined SO₂/NO_x technologies will be further evaluated as 1) additional information becomes available from on-going development or proof of concept programs, and 2) as the requirements for the post combustion controls become better defined with progress on combustion system development.
3. A priority will be placed on selecting one or more regenerable processes which support other system requirements such as heat recovery and toxics control. These will be developed and integrated with the LEBS analytically in the balance of Phase I, with objective of further development of a single process in Phase II.

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Section 6

LOW TEMPERATURE HEAT RECOVERY

Reduction of flue gas exit temperature is expected to contribute up to 1% gain in plant efficiency without extraordinary development or large increases in materials cost. Further gains may be possible depending on the development and economics of improved materials, and alternative system arrangements. Heat pipe and plate-type air heaters, both commercial and in development, offer potential advantages in surface temperature uniformity, compactness, leak-free operation, and lack of moving parts.

Figure 6.1 shows the effect of final flue gas exit temperature on efficiency. Note that in this figure, the relative efficiency is shown, which would apply to either boiler or plant efficiency. It is important to note the difference in absolute boiler vs plant efficiency percentage points: A 1.0 percent increase in boiler efficiency from a typical starting point of 90.0% gives 90.9% boiler efficiency; the corresponding change in net plant efficiency from a nominal starting point of 40.0% would give 40.4%. Conversely, an increase of 1.0 points plant efficiency (40.0 to 41.0) would require an relative increase in boiler efficiency of 2.5%, or a drop in flue gas exit temperature of about 90°F. The zero % relative value in Figure 6.1 is taken at 240°F. This is the value used in the performance and economic comparisons in Section 7. It is significantly lower than typical design temperatures for high sulfur coal (300-330°F), but considered achievable with current or moderately improved leak-free air heater designs. As discussed below, further reductions will depend on materials of construction as well as an available heat sink for the recovered energy. Finally, the notation "slagging combustion" means only that the values were calculated for an excess air of 10% (see Section 7). Higher excess air would show a slightly greater slope.

6.1 USE OF RECOVERED HEAT

The simplest use for the additional heat captured from the flue gas is for additional air preheat. Limitations are imposed by corrosion, deposition, and economics of the additional heat transfer surface. Just as importantly, the heat balance must be

Plant Efficiency vs. Slagging Combustion Air Heater Exit Temperature

Figure 6.1 Relative Change in Boiler or Plant Efficiency at Reduced Flue Gas Exit Temperature

satisfied consistent with required and allowable combustion air temperature, and the optimization of economizer vs air heater duty.

Figure 6.2 shows the results of a simple heat balance on the combustion air and flue gas. Flue gas and air rates were taken from the low excess air (slagging) cases of Section 7. All combustion air was assumed to be heated to the same final temperature. (In reality, part of the air would be bypassed to control pulverizer outlet temperature. However, this effect is small, since for the design coal the primary air temperature required for drying the coal is almost as high as the typical preheat temperature.)

Lower flue gas air heater exit temperatures require lower economizer flue gas exit temperature and lower hot end approach (flue gas and air differential) temperature. The former effects the distribution of the boiler heat transfer surface, the latter requires larger air heater surface. The economizer outlet (air heater inlet) flue gas temperature in conventional utility boiler designs is typically in the range of 650° to 800°F. A typical range for hot end approach temperature would be 50°F to 100°F, with air heater size increasing rapidly below 50 F. For the conditions in Figure 6.2, the temperature of the flue gas leaving the air heater can be no lower than 240 F for 650 F economizer outlet gas and a 50 F hot end approach. While the economizer temperature can be reduced in a new design, this not only effects boiler optimization but reduces the maximum available air preheat temperature (in the example cited, $650 - 50 = 600$ Fair preheat). This can effect combustion stability and efficiency

One further system integration issue is the temperature entering the scrubber, in the event that one is used. In principal, scrubbing takes place at saturation, and the flue gas is cooled by water sprays only to reach this temperature, wasting whatever heat is available. However, this spray is an important part of the overall water balance in a conventional limestone FGD system. Depending on the coal type, chloride balance, gypsum washing requirements, and demister washdown, there may be water in excess of "blowdown", ie, the waste water stream used to maintain proper concentrations in the scrubber. This excess water can normally be "disposed" of by evaporating it to cool the flue gas. If the flue gas is cooled to very low levels, this may require redesign of the scrubber water balance. In this regard, dry SO₂ removal processes, or wet processes which do not generate excess process water, would be advantageous for heat recovery. A completely dry SO₂ removal process operating well above the acid dewpoint would have the further advantage that SO₂ and SO₃ would be removed prior to final heat exchange.

Figure 6.2 Heat Balance for Combustion Air and Flue Gas

More advanced arrangements of back end heat recovery systems include bottoming steam cycles and split duty air heaters, feedwater heaters for displacing turbine extraction steam, and ammonia rankine cycles. The bottoming steam cycle extracts heat following the economizer to drive a separate turbine. The ammonia Rankine cycle can be used to convert heat to shaft work at very low temperatures. One system examined used working fluid between 113 and 154°F. Economic evaluations¹ showed capital costs of 2000-3500 \$/kW for bottoming steam systems including a new turbine and condenser, and 4,000 \$/kW for an ammonia based system. These systems are not anticipated to be cost effective.

Condensate/Feedwater Heating

Simple heat extraction is expected to be far more economical than separate steam or ammonia bottoming cycles. What is required is a low temperature sink capable of absorbing the heat from flue gas at 240°F and lower in a useful form. Convective preheating of boiler feedwater is one sink which could absorb all available heat in flue gas down to any reasonable temperature (again, limited by economics of large, corrosion resistant surface). In the high performance steam cycle shown Section 3, water leaves the condenser at about 110°F. This condensate is normally heated with steam extracted from various stages of the turbines in a series of feedwater heaters. Convective heating of the feedwater would replace one or more stages of extraction steam, allowing the steam instead to be run through the turbine to generate additional power.

Several arrangements of feedwater heating are being examined from the viewpoint of efficiency and integration into the high performance cycle. It must be emphasized that if the flue gas is cooled using condensate, rather than air, the typical efficiency vs exit temperature curves such as shown in Figure 6.1 do not apply. This is illustrated in the following paragraphs.

The simplest case, and the one offering the greatest driving force (coldest condensate) for cooling the flue gas, is shown in Figure 6.3. In this arrangement, all of the condensate is heated, replacing the lowest temperature feedwater heater. This condensate is heated by the full flue gas stream in a heat exchanger which is placed in series following the conventional air heater. This arrangement, while simple and minimizing heat exchanger size, converts the sensible heat of the flue gas to work at about 7-10% efficiency, or 15-25% of the nominal efficiency of the overall cycle (40%).

LEBS Steam Cycle

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Condensate Heater Replaces Low Pressure Feedwater Heater

Figure 6.3 Replacement of Low Temperature Extraction Steam Heater with Heat Recovery from Flue Gas

In this arrangement, a change in flue gas temperature of 100°F gave only two-tenths of a point increase in plant efficiency, compared to a full point expected from curves such as Figure 6.1. This return would justify very little expenditure on added equipment.

Several alternate arrangements are being explored, all based on bypassing part of the condensate from the extraction steam heaters, and heating it with a portion of the flue gas in an exchanger parallel with the air heater. Two are shown for illustration. In Figure 6.4, a portion of the condensate bypasses all of the extraction steam heaters and is heated by flue gas, whereas in Figure 6.5, a portion bypasses four of the extraction steam heaters in the higher temperature end of the train. Both of these arrangements converted heat to work at about 25% efficiency, or 60% relative to the overall cycle. Current investigations are looking at the trade offs between added cost and increased efficiency. The best arrangement to date bypasses the very high pressure feedwater or heater as well, and has an incremental efficiency of about 36%, or nearly 90% as efficient as the base cycle. Piping, pump, and heat exchanger costs are being evaluated for these arrangements.

6.2 HEAT EXCHANGER DESIGN

Heat pipe and plate type heat exchangers are being evaluated for air heat duty. Both are leak-free or have greatly reduced rates of leakage between the air and flue gas streams as compared to regenerative heaters, the most common type in use today. Elimination of air heater leakage can give a small, but significant improvement in boiler efficiency with no reduction in temperature. Both technologies have made inroads into the industrial and small utility market, and thus appear to be competitive with the regenerative heaters. Particularly for the concepts incorporating the Textron combustor, the high air supply pressures would give unacceptable leakage in the regenerative design.

Condensate heaters may employ special coatings for corrosion resistance, or may even utilize totally nonmetallic tube construction. A number of these nonmetallic heat exchangers are in full scale service in Europe for recovery heat recovery into warm water district heating systems, that is, for very low temperature, low pressure applications. The high efficiency, parallel flow, split flue gas and condensate arrangements described in Section 6.1 will need to handle condensate at relatively high temperature and pressure; one of the advantages is that the condensate heater

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Condensate Heater Flow Bypasses ALL Feedwater Heaters

Figure 6.4 Partial Bypass of all Feedwater Heaters

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Condensate Heater Flow Bypasses High Pressure Feedwater Heaters

Figure 6.5 Partial Bypass of High Pressure Feedwater Heaters

can be designed so that the minimum water side temperature is above the acid dewpoint.

6.3 CONCLUSIONS

1. The basic concepts evaluated for cost and efficiency in Section 7 will assume a final flue gas temperature entering the scrubber of 240°F, with all heat used to preheat combustion air. Engineering analysis and vendor information will be used to determine if this temperature is optimum for a system employing air preheat only (ie, no condensate heat), and to determine the most effective type of exchanger. Heat exchanger duty may be split to accommodate particulate cleanup at temperatures well above the acid dewpoint.
2. Additional heat recovery will focus on heating of a portion of the condensate/boiler feedwater to replace extraction steam. Issues will include efficiency benefits of extraction steam replacement, as well as economics and performance of various design approaches. An approach has been identified which appears to offer very high efficiency in converting low grade heat to power, but the economics of this system will need to be carefully evaluated. The concept utilizes parallel air and condensate heaters, with a final air heater in series.

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Section 7

ANALYSIS OF ALTERNATIVE LEBS CYCLE AND FIRING CONCEPTS

The evaluation of the development potential of an advanced slagging firing system is the most critical issue in this phase of the program. Therefore, this section presents an analysis which focuses on the comparison of alternative firing systems, with downstream subsystems (SO_2 , particulate control, heat recovery) assumed to be constant. However, steam conditions are included as one concept variation in order to evaluate the economics of the advanced cycle required to meet the program efficiency goals.

In this section, the following questions are addressed:

- What are the economics of a conventional, subcritical cycle, vs an advanced, supercritical cycle?
- If the objective of vitrified ash is met with conventional slagging design and post combustion NO_x control, what are the costs compared to the dry firing system?
- If the TVC meets the performance goals set for it, will the added operating costs (pressure drop, complexity) offset the improved performance (low NO_x , low furnace particulate)?

7.1 DESCRIPTION OF THE CONCEPTS

This section describes four basic concepts used to evaluate the economics of firing system/ NO_x control and cycle selection. All concepts incorporate the following common assumptions in order to focus on cycle and firing system selection:

- The coal is the Illinois No. 6 design coal, with the specific analysis as listed in Table 2-1. Both dry and advanced slagging systems will require fine coal to achieve low NO_x and minimize carbon loss. All cases assumed 80% through 200 mesh coal size, that is, the specific power for milling (kWh/ton) was assumed constant.
- Desulfurization is by advanced FGD, with adjustment made for changes in flue gas volume, amount of sulfur to be removed.

- Particulate control is with an advanced design, high-efficiency electrostatic precipitator.
- Stack temperature is 240°F, using zero-leakage air heater (implies plate or heat pipe type). This is low compared to typical practice for high sulfur coal, but achievable with current to moderately advanced technology.
- The gross generator output was fixed at 435 MWe, with the net output allowed to vary about the nominal 400 MWe by a few MWe, depending auxiliary power requirements.
- Economic evaluation was at the contract emission specifications (0.2 lbs/MBtu NO_x and SO_x, 0.015 lb/MBtu particulate) with the recognition that design flexibility to meet lower limits will be important.
- Fly ash and slag disposal costs were assumed identical for the initial comparison of dry and wet systems. The impact of varying disposal costs is examined in a subsequent sensitivity analysis.

The four cases are summarized in Table 7-1, and are described below.

7.1.1 Case 1, Subcritical Cycle, Dry Firing

This case utilizes a conventional subcritical cycle, nominally 2400 psi/1000 F, 1000°F single reheat. NO_x control is achieved with advanced, low-NO_x burners with dry ash removal. Typical values were assumed for combustion air and flue gas pressure drop, auxiliary power, excess air (20%) and carbon loss (0.5%).

A block diagram showing the air supply system for determination of FD auxiliary power is shown in Figure 7.1

7.1.2 Case 2, Supercritical Cycle, Dry Firing

This case moves to the advanced supercritical cycle described in Section 3, nominally 4500 psia/1100°F, with 1100/1100°F double reheat. NO_x control is achieved with advanced low-NO_x burners with dry ash removal, with the same pressure drop requirements and carbon loss assumed in Case 1. Boiler, turbine, and auxiliary capital costs are based on the SOAPP plant design, and are significantly higher than Case 1. Most auxiliary power requirements decrease due to the smaller amount of air, fuel and

Table 7-1

Summary of LEBS Concepts, Cost and Performance

Case	1	2	3	4
Firing system	LNB-dry	LNB-dry	U-slugging	TVC slugging (70% @ 40 IWC)
Boiler	drum	once-through	once-through	once-through
Fuel	IL No. 6	IL No. 6	IL No. 6	IL No. 6
Boiler NOx lb/MBtu	0.2	0.2	0.6	0.2
SCR	No	No	Yes	No
FGD	Yes	Yes	Yes	Yes
Nominal Cycle	Subcritical	ASC	ASC	ASC
psia	2400	4500	4500	4500
Main Deg F	1000	1100	1100	1100
Reheat Deg F	1000	1100/1100	1100/1100	1100/1100
NTHR, Btu/kWh	8005	7083	7083	7083
BOILER				
Excess Air, %	20	20	10	10
Carbon loss, %	0.5	0.5	0.1	0.1
Unacct loss, %	0.5	0.5	0.8	0.8
AH exit, F	240	240	240	240
AH leakage	0	0	0	0
Boiler Efficiency	90.17	90.17	90.54	90.54
boiler ash load, %	80	80	100	20
FD dP, IWC	100% to 20"	100% to 20"	90% to 20"	40% to 20"
(% of stoich)	20% to 45"	20% to 45"	20% to 45"	50% to 50"
				20% to 80"
ID dP, IWC	30	30	38	30
Gross output, MWe	435	435	435	435
Aux power, %gross	7.13	7.35	7.62	7.6
Net output, MWe	404.0	403.0	401.9	401.9
NPHR, Btu/kWh	9558	8484	8471	8477
Net Efficiency, %	35.7	40.2	40.3	40.3
Levelized c/kWh				
no externalities	6.10	6.22	6.43	6.20
with externalities	8.99	8.77	8.98	8.75

flue gas processed (higher efficiency) relative to the subcritical design, but there is a small net increase in auxiliary power due to feedwater booster pumps for the higher pressure cycle. A significant cost penalty is added as contingency associated with the supercritical cycle due to the developmental status.

The block diagram in Figure 7.1 for air supply auxiliary power applies to this case as well.

7.1.3 Case 3, Supercritical Cycle, U-fired Slagging

The same advanced cycle is fired with a commercial, slagging system. Since the U-fired design is fired with burners essentially identical to the dry fired system, air side pressure drop remains the same as in Cases 1 and 2. However, lower excess air (10%) and lower carbon loss (0.1%) are assumed, based on existing full scale design data. This improves boiler efficiency but is partially offset by the thermal loss of quenching slag (shown as an increase of 0.3% in "unaccounted loss"). In order to keep cost estimates on the same basis, the boiler capital cost from Case 2 was increased 10% to account for the wet bottom design. This is a very rough approximation based on internal design experience, but was deemed sufficient for the purpose of this evaluation. Detailed boiler costs will be developed under later tasks.

Combustion modifications to operating, full scale U-fired boilers have reduced NO_x emissions to about 0.8 lb/MBtu, a reduction of about 50% from uncontrolled levels. A moderate additional reduction to 0.6 lb/MBtu for the combustion system is assumed, with SCR used to control to a final emission level of 0.2 lb/MBtu. Costs are incurred not only for capital equipment and reagent, but also for an increase in induced fan power requirement.

Note that although essentially 100% ash vitrification can be achieved with this combustion system, the once-through ash retention is about 50%. With recycle for complete vitrification, the ash loading to the boiler is approximately 100% of the coal ash input, compared to 80% typical for dry firing systems. No adjustment to boiler size or capital cost was made.

The U-Fired arrangement is shown in Figure 7.2.

Figure 7.1 Air Supply Block Diagram For FD Auxiliary Power Dry Fired Low NOx Burners

Figure 7.2 Air Supply Block Diagram For FD Auxiliary Power
U-fired System

7.1.4 Case 4, Supercritical Cycle, TVC-firing

The same advanced cycle is fired with the Toroidal Vortex Combustor. Excess air, carbon loss, and slag thermal loss are kept as in Case 3. The most significant changes are as follows.

Auxiliary power increases due to much higher combustor pressure drop. The minimum TVC pressure drop is projected to be 40 IWC (inches water column), with about 70% of stoichiometric air passing through the TVC and the remainder admitted as overfire air (at the same pressure as windbox/OFA in the dry firing case). Higher pressures are examined in a later sensitivity analysis.

NO_x is assumed to be controlled to 0.2 lb/MBtu with the combustor. Capital, reagent, and ID power costs associated with SCR are eliminated compared to Case 3

The boiler capital cost is reduced due to the lower ash loading projected for the TVC-fired system. Higher once-through ash retention results in reduced loading to the boiler (including recycle to maintain essentially 100% vitrification):

<u>Once-through retention</u>	<u>Boiler loading, % of coal ash</u>
50	100
65	54
80	25
85	18
90	11
95	5.3

Retention of 90% has been demonstrated in pilot scale TVC tests. 85% retention will be assumed for evaluation of detailed analysis of boiler size in later tasks. For the purpose of this analysis, the capital cost of the boiler was reduced about 20% compared to Case 3, based on a comparison of oil-fired and coal-fired conventional cycle boilers. This may be somewhat overstating the potential reduction in size and tube spacing, but is a good basis for estimating the maximum benefit of reduced particulate loading.

Figure 7.3 shows a block diagram for the TVC air supply.

7.2 ECONOMIC EVALUATION

A detailed economic evaluation of the four case described above is contained in Appendix 1. The evaluation uses EPRI TAG methodology, and incorporates the following economic assumptions:

- 30 year plant life
- 65% capacity factor, 90% availability, base load operation
- 5.47% discount rate
- 60 months, start of engineering to completion
- Constant dollar analysis (no inflation)
- No escalation except 1% for fuel.

The following sections present a summary of the results of the economic analysis by comparing cases and breaking out the costs of process changes (eg, a change in combustion air pressure drop) in terms of change to cost of electricity. For example, a net change in levelized capital cost may be the sum of increases and decreases in various areas of the plant. These are itemized to illustrate the cost impacts of the alternate subsystems.

It should be recognized that the COE figures presented include many assumptions, both technical and economic. The costs are not intended to represent absolute values, but as a means of estimating changes to the base value. This is best expressed as a percentage change to a base case, however, it is convenient to be able to compare costs on a cents-per-kilowatt basis. Both methods are used in the following discussion.

7.2.1 COE, Basic Concepts

The levelized cost of electricity for the concepts as described above is shown in Table 7-1. For each concept, two costs are shown: cost without externalities, and cost with externalities. The values for externalities are those published by the Massachusetts

Figure 7.3 Air Supply Block Diagram For FD Auxiliary Power
TVC Fired System

Department of Public Utilities, and include per-ton costs for sulfur dioxide, nitrogen oxides, and carbon dioxide.

Externality costs are particularly important in comparing designs with different efficiencies. While externalities do not represent a "real" cost which must be paid out of revenues, there is a trend by states to require that externality costs be quantitatively considered by utilities in evaluating the least cost option for new power generation (or conservation). While one can argue whether the values used are "correct", some account of environmental impact will be required for many, if not most, future process evaluations.

7.2.2 Cycle Efficiency: Case 1 vs Case 2

As discussed in Section 3, the program goals for efficiency can be met only with an advanced supercritical cycle. In this sense, Case 1 is not a viable LEBS concept. However, it is instructive to look at the impact of cycle efficiency on cost.

When externality cost is excluded, the subcritical cycle is less expensive based on the assumptions used in this analysis, most notably for this comparison, fuel cost and capital cost. Table 7-2 shows the significant changes to COE in moving from Case 1 to Case 2. The major reduction in cost is in reduced fuel consumption.

Interestingly, about two-thirds of the increase in capital cost due to the supercritical boiler and turbine are offset by decreases in the balance of plant (BOP) due to reduced flows being handled. As mentioned under the description of Case 2, there is a substantial contingency cost attached to the advanced steam cycle. If the contingency cost for Case 2 is adjusted to that for Case 1, the Case 2 COE is reduced by 0.22 cents/KWH, ie, below Case 1, even at existing fuel cost and without externalities. While the higher contingency cannot be legitimately excluded from the analysis, this does indicate the potential for reduced COE with the advanced cycle.

Figure 7.4 shows the effect of increasing fuel cost on the cycle cost comparison. Only for much higher fuel cost is the supercritical cycle more economical (including higher contingency, and without externalities).

When externalities are included, the supercritical cycle is favored. As shown in Figure 7.5, this is true with externality costs as low as 30% of the values used for the base evaluation (Massachusetts Department of Public Utilities). At SO₂ and NO_x emission

Table 7–2

Comparative Costs of Subcritical and Supercritical Cycles

cents/kwh

6.10	Case 1, Low NOx Burners, Subcritical Cycle
0.182	Increased capital for high pressure boiler, turbine
<u>-0.121</u>	<u>Decreased capital BOP (reduced flows)</u>
0.061	Net capital change exclusive of contingency
-0.198	Fuel savings for same gross output
0.015	Aux power net (+feedwater aux, -BOP aux)
0.042	Fixed O&M costs
<u>-0.021</u>	<u>Variable O&M costs</u>
6.00	Subtotal exclusive of contingency
<u>0.220</u>	<u>Increased contingency for advanced cycle</u>
6.22	Case 2, LNB, Advanced Supercritical cycle

Table 7–3

Comparative Costs of Dry Firing and U–Fired Concepts

cents/kwh

6.22	Case 2, Low NOx Burners, Advanced Supercritical
-0.006	Boiler efficiency gain
-0.003	FD aux power reduction (lower excess air)
-0.005	ID aux power reduction (lower excess air)
0.033	Increased capital cost for wet bottom operation
<u>0.007</u>	<u>Increased aux power for ash removal/recycle</u>
6.24	Subtotal without SCR
<u>0.190</u>	<u>Add SCR (capital, reagent, added ID aux power)</u>
6.43	Case 3, U–Fired Slagging with SCR

Effects of Differential Fuel Cost

Figure 7.4 Effect of Increased Fuel Cost on COE

Cost of Electricity vs. Externalities Charges

Figure 7.5 Cost of Electricity vs. Externalities Charges

rates of 0.2 lb/MBtu, the largest part of externality cost is due to CO₂ emission. Excluding very advanced and expensive control schemes, improved efficiency is the only means to lower this cost for a given fuel.

All subsequent comparisons are between concepts having similar plant efficiencies, and are therefore simplified by excluding externality costs.

7.2.3 Ash Vitrification with Post-Combustion NO_x Control: Case 3 vs Case 2

One approach to producing vitrified ash is to utilize existing slagging designs with modest improvements in combustion NO_x control and SCR for post combustion control of NO_x. This is represented by Case 3, whose incremental costs relative to dry firing are presented in Table 7-3

In the absence of SCR, relatively small increases in boiler capital and ash handling auxiliary power are nearly offset by gains in boiler efficiency and fan auxiliary power (lower excess air, increased carbon utilization). However, the cost of SCR results in a net increase in COE of about 2.4% for this option. Even this modest increase may be exaggerated by comparing one case with SCR and one without. Due to the likelihood of lower emission requirements and the possibility of final control devices being specified by regulators, the proper comparison may be between U-fired with a large SCR and dry-firing with a small SCR system. SCR costs as a function of inlet level and outlet limit were shown in Figure 5.1.

While the U-firing plus SCR concept is nominally the highest COE of the advanced cycle concepts presented, the relative cost increase is small. The development requirements for this concept are limited (modest improvement in combustion NO_x control, adaptation/demonstration of high-dust catalysts and slag chamber refractory to high-sulfur US coal).

Recall also that both cases assumed identical ash and slag disposal costs. A differential cost of disposal/byproduct sale of about \$30/ton would equalize the COE between Cases 2 and 3. This trend is shown in Figure 7.6

7.2.4 Ash Vitrification with Combustion NO_x Control: Case 4 vs Case 2

If the TVC can meet design goals of NO_x control, then post combustion control is eliminated from the comparison. Table 7-4 shows that the major increases in COE

Effects of Differential Slag Disposal Cost

Figure 7.6 Effects of Differential Slag Disposal Cost

Table 7-4

Comparative Costs of Dry Firing and TVC Concepts

cents/kwh

6.22	Case 2, Low NOx Burners, Advanced Supercritical
-0.006	Boiler efficiency gain
-0.003	FD aux power reduction (lower excess air)
-0.005	ID aux power reduction (lower excess air)
0.033	Increased capital cost for wet bottom operation
0.029	Increased FD aux power (70% @ 40 IWC)
0.025	Increased capital for combustors, fans
-0.003	Decreased aux power for ash removal, handling
6.29	Subtotal, TVC with no boiler size reduction
-0.087	Reduced capital cost for boiler
6.20	Case 4, TVC slagging system, 40"dP
6.22	TVC, 60"dP

Table 7-5

Comparative Costs of U-Fired and TVC Concepts

cents/kwh

6.43	Case 3, U-Fired, Advanced Supercritical with SCR
-0.190	Eliminate SCR capital, reagent, aux power
-0.087	Reduced capital cost for boiler
-0.009	Decreased aux power for ash removal, handling
0.023	Increased capital cost for combustors, fans
0.029	Increased FD aux power (70% @ 40 IWC)
6.20	Case 4, TVC slagging system, 40"dP

stem from increased auxiliary power for combustion air and increased capital cost for burners and fans, and for the wet-bottom boiler design. These are offset in part by decreased cost for auxiliary power and increased boiler efficiency, as was the case for conventional slagging design. A TVC-fired boiler with no change in boiler size gives a COE midway between that of Cases 2 and 3. However, if boiler size can be reduced to the extent assumed (ie, to an oil-fired design), the COE is reduced to essentially that of dry firing, even with no cost differential for slag and ash.

A disposal differential of \$20/ton would reduce the cost of Case 4 relative to Case 2 by about 1 mill/kWh, as shown in Figure 7.6.

7.2.5 Combustion vs Post-Comb. Control for Slagging Systems: Case 2 vs Case 4.

A direct comparison between slagging systems eliminates changes in boiler efficiency and illustrates the trade off between SCR and boiler capital vs increased auxiliary power for the TVC. This is shown in Table 7-5

7.3 CONCLUSIONS

The TVC, if successfully developed to meet the NO_x and ash retention goals outlined in this report, will be a cost-effective means of firing coal with the production of vitrified ash. In comparison to an alternative slagging design, the ability to control NO_x through combustion will make up for additional auxiliary power required to run the combustion system. In comparison to either an alternative slagging design or low-NO_x dry firing, savings in boiler capital due to reduced particle loading may be substantial.

The preceding economic comparison of firing systems and steam cycles, in order to focus on these systems, used costs for a conventional air heater and limestone scrubber. However, other sections identified an advanced low temperature heat recovery concept, and the need for a regenerable sulfur oxide control system to fully meet the goals of waste reduction for this program. Therefore, the concept proposed for development is as shown in Figure 7.7: A U-fired slagging design supercritical boiler is adapted as a platform for the TVC. An advanced heat recovery system allows efficient conversion of low grade heat. A number of regenerable processes have been evaluated which appear to be competitive with conventional FGD. These include dry systems operating above the acid dewpoint, which would minimize potential corrosion

Figure 7.7 Low Emission Boiler System Concept

problems in the low temperature air heater. Such systems will be investigated for integration into the boiler concept.

While the TVC is promising, there is substantial development work required to prove this technology. This will include experimental testing in Phase I. In parallel, the U-fired technology will be studied for better NO_x control with a commercially available, slagging technology. The concept is similar to that for the TVC, except that SCR or a combined SO_x/NO_x process would be required.

APPENDIX 1

DETAILS OF CONCEPT ECONOMIC ANALYSIS

Low Emission Boiler System (LEBS) Concept Alternatives

TECHNOLOGY:		1	2	3	4	5
		PC	ASCPC	ASCPC	ASCPC	ASCPC
COMBUSTION SYSTEM:		Low NOx Burners	Low NOx Burners	U-Fired Slagging Burners	Toroidal Vortex Combustor (40" dp)	Toroidal Vortex Combustor (60" dp)
AQCS SOx CONTROL:		Wet FGD	Wet FGD	Wet FGD	Wet FGD	Wet FGD
Combustion % SOx Control		0	0	0	0	0
NOx CONTROL:		LNB	LNB	SCR	TVC	TVC
STEAM CYCLE						
Pressure	psi	2400	4500	4500	4500	4500
Temperatures	°F	1000/1000	1100/1100/1100	1100/1100/1100	1100/1100/1100	1100/1100/1100
LOAD (% MCR)	UNITS	100	100	100	100	100

PLANT PERFORMANCE:

Plant Efficiency	%	35.7	40.2	40.3	40.3	40.2
Net Plant Heat Rate	Btu/kW*h	9,558	8,478	8,468	8,466	8,491
Gross Plant Output	kW	435,000	435,000	435,000	435,000	435,000
Net Plant Output	kW	403,992	403,047	401,849	401,945	400,770
Gross Plant Heat Rate, HHV	Btu/kW*hr	8,877	7,855	7,823	7,823	7,823
Auxiliary Power	kW	31,008	31,953	33,151	33,055	34,230
Net (Steam) Turbine Heat Rate	Btu/kW*h	8,005	7,083	7,083	7,083	7,083
Primary Fuel Feed Rate	lb/hr	357,550	316,380	315,094	315,094	315,094
Sorbent Feed Rate - Combustion System	lb/hr	0	0	0	0	0
Sorbent Feed Rate - AQCS	lb/hr	45,588	40,338	40,175	40,175	40,175
Ammonia Feed Rate	lb/hr	0	0	511	0	0
Water Consumption	gpm	4,110	3,789	3,789	3,789	3,789
Ash Flow Rate	lb/hr	28,604	25,310	25,208	25,208	25,208
Solid Waste Production	lb/hr	69,510	61,506	61,256	61,256	61,256

FUEL (NAME):	Illinois No. 6	Illinois No. 6	Illinois No. 6	Illinois No. 6	Illinois No. 6
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Ultimate Analysis

Carbon	%	59.2	59.2	59.2	59.2	59.2
Sulfur	%	3.4	3.4	3.4	3.4	3.4
Oxygen	%	8.7	8.7	8.7	8.7	8.7
Hydrogen	%	4.2	4.2	4.2	4.2	4.2
Nitrogen	%	1.0	1.0	1.0	1.0	1.0
Chlorine	%	0.1	0.1	0.1	0.1	0.1
Ash	%	8.0	8.0	8.0	8.0	8.0
Moisture	%	15.5	15.5	15.5	15.5	15.5
Gross heating value	Btu/lb	10,800	10,800	10,800	10,800	10,800
Hardgrove grindability	HGI	53	53	53	53	53

Ash Analysis

Silica	%	49.5	49.5	49.5	49.5	49.5
Ferric oxide	%	16.6	16.6	16.6	16.6	16.6
Alumina	%	21.1	21.1	21.1	21.1	21.1
Titanic oxide	%	1.0	1.0	1.0	1.0	1.0
Calcium oxide	%	3.7	3.7	3.7	3.7	3.7
Magnesia	%	1.0	1.0	1.0	1.0	1.0
Sulfur trioxide	%	2.2	2.2	2.2	2.2	2.2
Potassium oxide	%	2.3	2.3	2.3	2.3	2.3
Sodium oxide	%	1.6	1.6	1.6	1.6	1.6
Phosphorous pentoxide	%	2.0	2.0	2.0	2.0	2.0
Undetermined	%	1.8	1.8	1.8	1.8	1.8

Low Emission Boiler System (LEBS) Concept Alternatives

TECHNOLOGY:	1	2	3	4	5
	PC	ASCPC	ASCPC	ASCPC	ASCPC
COMBUSTION SYSTEM:	Low NOx Burners	Low NOx Burners	U-Fired Slagging Burners	Toroidal Vortex Combustor (40" dp)	Toroidal Vortex Combustor (60" dp)

SORBENT:

CaCO ₃	%	90	90	90	90	90
MgCO ₃	%	5	5	5	5	5
CaO	%	0	0	0	0	0
Ash	%	2	2	2	2	2
Moisture	%	3	3	3	3	3
Sorbent - Calcium Available	lbCa/lbsrb	0.36	0.36	0.36	0.36	0.36

EMISSIONS:**REQUIREMENTS:**

SO _x - NSPS	lb/MBtu	1.2	1.2	1.2	1.2	1.2
NO _x - NSPS	lb/MBtu	0.7	0.7	0.7	0.7	0.7
Particulate - NSPS	lb/MBtu	0.1	0.1	0.1	0.1	0.1
Sulfur Retention for NSPS	%	81	81	81	81	81
SO _x - LEBS	lb/MBtu	0.2	0.2	0.2	0.2	0.2
NO _x - LEBS	lb/MBtu	0.2	0.2	0.2	0.2	0.2
Particulate - LEBS	lb/MBtu	0.015	0.015	0.015	0.015	0.015
Sulfur Retention for LEBS	%	97	97	97	97	97
SO _x - SOAPP	lb/MBtu	0.1	0.1	0.1	0.1	0.1
NO _x - SOAPP	lb/MBtu	0.06	0.06	0.06	0.06	0.06
Particulate - SOAPP	lb/MBtu	0.005	0.005	0.005	0.005	0.005
Sulfur Retention for SOAPP	%	98	98	98	98	98

FROM COMBUSTION SYSTEM:

SO _x - Uncontrolled	lb/MBtu	6.30	6.30	6.30	6.30	6.30
Sulfur Retention - Combustion System	%	0	0	0	0	0
Calcium to Sulfur Molar Ratio		0.00	0.00	0.00	0.00	0.00
SO _x - from Combustion System	lb/hr	24,313	21,514	21,426	21,426	21,426
SO _x - from Combustion System	lb/MBtu	6.296	6.296	6.296	6.296	6.296
SO _x - from Combustion System	ppmvd	3,617	3,617	3,617	3,617	3,617
NO _x - from Combustion System	lb/MBtu	0.20	0.20	0.60	0.20	0.20
NO _x - from Combustion System	ppmvd	157	157	476	159	159
Bottom Ash	%	20	20	50	85	85

FROM AIR QUALITY CONTROL SYSTEM:

Sulfur Retention for NSPS	%	81	81	81	81	81
Sulfur Retention for LEBS	%	97	97	97	97	97
Sulfur Retention for SOAPP	%	98	98	98	98	98
Calcium to Sulfur Molar Ratio		1.08	1.08	1.08	1.08	1.08
SO _x - from AQCS	lb/hr	772	683	681	681	681
SO _x - from AQCS	lb/MBtu	0.200	0.200	0.200	0.200	0.200
SO _x - from AQCS	lb/MW/hr	1.91	1.70	1.69	1.69	1.70
SO _x - from AQCS	ppmvd	115	115	115	115	115
NO _x Conversion Efficiency NSPS	%	0	0	0	0	0
NO _x Conversion Efficiency LEBS	%	0	0	67	0	0
NO _x Conversion Efficiency SOAPP	%	70	70	90	70	70
S(NICR Ammonia Slip (@ 3% O ₂))	ppmvd	5	5	5	5	5
NH ₃ /NO ₂ Molar Ratio -NSPS		0.00	0.00	0.00	0.00	0.00
NH ₃ /NO ₂ Molar Ratio -LEBS		0.00	0.00	0.68	0.00	0.00

Low Emission Boiler System (LEBS) Concept Alternatives

TECHNOLOGY:		1	2	3	4	5
		PC	ASCPC	ASCPC	ASCPC	ASCPC
COMBUSTION SYSTEM:		Low NOx Burners	Low NOx Burners	U-Fired Slagging Burners	Toroidal Vortex Combustor (40" dp)	Toroidal Vortex Combustor (60" dp)
NH3/NO2 Molar Ratio -SOAPP		0.73	0.73	0.91	0.73	0.73
NOx - Controlled - LEBS	lb/hr	772	683	681	681	681
NOx - Controlled - LEBS	lb/MBtu	0.20	0.20	0.20	0.20	0.20
NOx - Controlled - LEBS	lb/MW/hr	1.91	1.70	1.69	1.69	1.70
NOx - Controlled - LEBS	ppmvd	160.	160.	160.	160.	160.
Excess Air (Normalized)	%	17 @3%O2	17 @3%O2	17 @3%O2	17 @3%O2	17 @3%O2
Particulate - Controlled - LEBS	lb/MBtu	0.015	0.015	0.015	0.015	0.015
Particulate - Controlled	lb/hr	58	51	51	51	51
Particulate - Controlled	lb/MW/hr	0.143	0.127	0.127	0.127	0.127
Particulate Removal Efficiency - NSPS	%	98.31	98.31	97.30	91.00	91.00
Particulate Removal Efficiency -LEBS	%	99.75	99.75	99.80	98.88	98.88
Particulate Removal Efficiency - SOAPP	%	99.92	99.92	99.87	99.55	99.55
CO2 Uncontrolled	lb/MBtu	201	201	201	201	201
CO2 Uncontrolled	lb/hr	775,466	686,175	683,387	683,387	683,387
CO2 Uncontrolled	lb/MW/hr	1,920	1,702	1,701	1,700	1,705

STEAM GENERATOR:

Theoretical air	lb/lbfuel	8.04	8.04	8.04	8.04	8.04
Theoretical dry gas	lb/lbfuel	8.43	8.43	8.43	8.43	8.43
Excess Air	%	20	20	10	10	10
Total Dry Air Flow	lb/lbfuel	9.65	9.65	8.85	8.85	8.85
Ambient Air Moisture	lb/lbair	0.013	0.013	0.013	0.013	0.013
Total Air Flow	lb/lbfuel	9.78	9.78	8.96	8.96	8.96
Flue Gas Moisture Flow	lb/lbfuel	0.66	0.66	0.65	0.65	0.65
Products of Combustion	lb/lbfuel	9.09	9.09	9.08	9.08	9.08
Air Heater Leakage	%	0	0	0	0	0
Airheater Inlet Temperature	°F	100	100	100	100	100
Infiltration	%	5	5	5	5	5
Exit Flue Gas Temperature	°F	240	240	240	240	240
Flue gas Temperature Uncorrected	°F	240	240	240	240	240
Combustion Air Flow	lb/hr	3,495,670	3,093,162	2,823,874	2823874	2,823,874
Combustion Air Flow	acfm	828,075	732,726	668,936	668,936	668,936
Flue Gas Flow Rate	lb/hr	4,006,774	3,545,416	3,258,160	3,258,160	3,258,160
Flue Gas Flow Rate	acfm	1,158,693	1,025,276	943,554	943,554	943,554
T Inlet Enthalpy	Btu/lb	68.0	68.0	68.0	68.0	68.0
T Uncorrected Enthalpy	Btu/lb	1,160.4	1,160.4	1,160.4	1,160.4	1,160.4
Radiation Loss	%	0.19	0.19	0.19	0.19	0.19
Dry Gas Heat Loss	%	3.14	3.14	2.88	2.88	2.88
Fuel Moisture Loss	%	1.57	1.57	1.57	1.57	1.57
Hydrogen in Fuel Loss	%	3.85	3.85	3.85	3.85	3.85
Air Moisture Heat Loss	%	0.08	0.08	0.07	0.07	0.07
Calcination Loss (CaCO3)	%	0.00	N/A	N/A	N/A	N/A
Calcination Loss (MgCO3)	%	N/A	N/A	N/A	N/A	N/A
Carbon Loss	%	0.50	0.50	0.10	0.10	0.10
Unaccounted Loss	%	0.50	0.50	0.80	0.80	0.80
Manufacturer's margin	%	0.00	0.00	0.00	0.00	0.00
Total Boiler Loss	%	9.82	9.83	9.46	9.46	9.46

Low Emission Boiler System (LEBS) Concept Alternatives

TECHNOLOGY:		1	2	3	4	5
		PC	ASCPC	ASCPC	ASCPC	ASCPC
COMBUSTION SYSTEM:		Low NOx Burners	Low NOx Burners	U-Fired Slagging Burners	Toroidal Vortex Combustor (40" dp)	Toroidal Vortex Combustor (60" dp)
Sulfation Gain	%	N/A	N/A	N/A	N/A	N/A
Boiler Efficiency	%	90.18	90.17	90.54	90.54	90.54
Boiler Heat Output	MBtu/hr	3482.18	3081.11	3081.11	3081.11	3081.11
Main Steam Flow	lb/hr	3,016,630	2,632,850	2,632,850	2,632,850	2,632,850

STEAM TURBINE/CYCLE DATA:

Turbine Back Pressure	in HgA	2.5	2.5	2.5	2.5	2.5
Steam Turbine Gross Output	kW	435,000	435,000	435,000	435,000	435,000
LP Turbine Exhaust to Condenser	lb/hr	1,762,178	1,405,830	1,405,830	1,405,830	1,405,830
Exhaust Energy	Btu/lb	1,041.57	1,071.00	1,071.00	1,071.00	1,071.00
Condensate Enthalpy	Btu/lb	76.69	76.69	76.69	76.69	76.69
Heat Rejection from LP Turbine	Btu/hr	1.70E+09	1.40E+09	1.40E+09	1.40E+09	1.40E+09
BFP Turbine Drive Steam Flow	lb/hr	107,027	190,960	190,960	190,960	190,960
BFP Turbine Exhaust Enthalpy	Btu/lb	1,081.44	1,402.00	1,402.00	1,402.00	1,402.00
Heat Rejection from BFP Turbine	Btu/hr	1.08E+08	2.53E+08	2.53E+08	2.53E+08	2.53E+08
Total Heat Rejected to Condenser	Btu/hr	1.81E+09	1.65E+09	1.65E+09	1.65E+09	1.65E+09
Condenser Temp. Rise - Closed	°F	22	22	22	22	22
Condenser Temp. Rise - Open	°F	18	18	18	18	18
Circulating Water Flow - Closed	gpm	164,414	150,143	150,143	150,143	150,143
Circulating Water Flow - Open	gpm	200,950	183,508	183,508	183,508	183,508
Cooling Tower Air Flow	lb/lbw	1,158,327	1,057,788	1,057,788	1,057,788	1,057,788
Cooling Tower Air Flow	cfm	263,068	240,234	240,234	240,234	240,234

AUXILIARY POWER:

Condensate P/P	%	0.24	0.22	0.22	0.22	0.22
Circulating Water P/P	%	0.68	0.62	0.62	0.62	0.62
Cooling Towers	%	0.20	0.18	0.18	0.18	0.18
Feedwater Booster P/P	%	N/A	0.70	0.70	0.70	0.70
Subtotal pumps/CWS	%	1.12	1.73	1.73	1.73	1.73
Induced Draft Fan Pressure Rise	"wc	30	30	38	30	30
Percent Total Air to FD Fan	%	83	83	82	45	45
Forced Draft Fan Pressure Rise	"wc	20	20	20	50	70
Percent Total Air to PA Fan	%	17	17	18	18	18
Primary Air Fan Pressure Rise	"wc	45	45	45	80	100
Percent Total Air to SA Fan	%	0	0	0	37	37
Secondary Air Fan Pressure Rise	"wc	15	15	15	20	20
Induced Draft Fan	%	1.14	1.01	1.18	0.93	0.93
Forced Draft Fan	%	0.45	0.39	0.35	0.48	0.68
Primary Air Fan	%	0.21	0.18	0.17	0.31	0.39
Secondary Air Fan	%	0.00	0.00	0.00	0.16	0.16
Pulverizer Capacity Factor	%	1.06	1.06	1.06	1.06	1.06
Pulverizer	%	0.65	0.57	0.57	0.57	0.57
Fuel Handling	%	0.14	0.13	0.13	0.13	0.13
Ash Handling	%	0.10	0.08	0.17	0.11	0.11
Particulate Removal	%	0.21	0.21	0.22	0.14	0.14
T-R power	kW	786	786	853	446	446
FGD	%	1.55	1.49	1.49	1.49	1.49
NOx Control	%	0.00	0.00	0.06	0.00	0.00

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Low Emission Boiler System (LEBS) Concept Alternatives

TECHNOLOGY:		1 PC	2 ASCPC	3 ASCPC	4 ASCPC	5 ASCPC
COMBUSTION SYSTEM:		Low NOx Burners	Low NOx Burners	U-Fired Slagging Burners	Toroidal Vortex Combustor (40" dp)	Toroidal Vortex Combustor (60" dp)
Sulfation Gain	%	N/A	N/A	N/A	N/A	N/A
Boiler Efficiency	%	90.18	90.17	90.54	90.54	90.54
Boiler Heat Output	MBtu/hr	3482.18	3081.11	3081.11	3081.11	3081.11
Main Steam Flow	lb/hr	3,016,630	2,632,850	2,632,850	2,632,850	2,632,850

STEAM TURBINE/CYCLE DATA:

Turbine Back Pressure	in HgA	2.5	2.5	2.5	2.5	2.5
Steam Turbine Gross Output	kW	435,000	435,000	435,000	435,000	435,000
LP Turbine Exhaust to Condenser	lb/hr	1,762,178	1,405,830	1,405,830	1,405,830	1,405,830
Exhaust Energy	Btu/lb	1,041.57	1,071.00	1,071.00	1,071.00	1,071.00
Condensate Enthalpy	Btu/lb	76.69	76.69	76.69	76.69	76.69
Heat Rejection from LP Turbine	Btu/hr	1.70E+09	1.40E+09	1.40E+09	1.40E+09	1.40E+09
BFP Turbine Drive Steam Flow	lb/hr	107,027	190,960	190,960	190,960	190,960
BFP Turbine Exhaust Enthalpy	Btu/lb	1,081.44	1,402.00	1,402.00	1,402.00	1,402.00
Heat Rejection from BFP Turbine	Btu/hr	1.08E+08	2.53E+08	2.53E+08	2.53E+08	2.53E+08
Total Heat Rejected to Condenser	Btu/hr	1.81E+09	1.65E+09	1.65E+09	1.65E+09	1.65E+09
Condenser Temp. Rise - Closed	°F	22	22	22	22	22
Condenser Temp. Rise - Open	°F	18	18	18	18	18
Circulating Water Flow - Closed	gpm	164,414	150,143	150,143	150,143	150,143
Circulating Water Flow - Open	gpm	200,950	183,508	183,508	183,508	183,508
Cooling Tower Air Flow	lb/lbw	1,158,327	1,057,788	1,057,788	1,057,788	1,057,788
Cooling Tower Air Flow	cfm	263,068	240,234	240,234	240,234	240,234

AUXILIARY POWER:

Condensate P/P	%	0.24	0.22	0.22	0.22	0.22
Circulating Water P/P	%	0.68	0.62	0.62	0.62	0.62
Cooling Towers	%	0.20	0.18	0.18	0.18	0.18
Feedwater Booster P/P	%	N/A	0.70	0.70	0.70	0.70
Subtotal pumps/CWS	%	1.12	1.73	1.73	1.73	1.73
Induced Draft Fan Pressure Rise	"wc	30	30	38	30	30
Percent Total Air to FD Fan	%	83	83	82	45	45
Forced Draft Fan Pressure Rise	"wc	20	20	20	50	70
Percent Total Air to PA Fan	%	17	17	18	18	18
Primary Air Fan Pressure Rise	"wc	45	45	45	80	100
Percent Total Air to SA Fan	%	0	0	0	37	37
Secondary Air Fan Pressure Rise	"wc	15	15	15	20	20
Induced Draft Fan	%	1.14	1.01	1.18	0.93	0.93
Forced Draft Fan	%	0.45	0.39	0.35	0.48	0.68
Primary Air Fan	%	0.21	0.18	0.17	0.31	0.39
Secondary Air Fan	%	0.00	0.00	0.00	0.16	0.16
Pulverizer Capacity Factor	%	1.06	1.06	1.06	1.06	1.06
Pulverizer	%	0.65	0.57	0.57	0.57	0.57
Fuel Handling	%	0.14	0.13	0.13	0.13	0.13
Ash Handling	%	0.10	0.08	0.17	0.11	0.11
Particulate Removal	%	0.21	0.21	0.22	0.14	0.14
T-R power	kW	786	786	853	446	446
FGD	%	1.55	1.49	1.49	1.49	1.49
NOx Control	%	0.00	0.00	0.06	0.00	0.00

Low Emission Boiler System (LEBS) Concept Alternatives

TECHNOLOGY:		1	2	3	4	5
		PC	ASCPC	ASCPC	ASCPC	ASCPC
COMBUSTION SYSTEM:		Low NOx Burners	Low NOx Burners	U-Fired Slagging Burners	Toroidal Vortex Combustor (40" d)	Toroidal Vortex Combustor (60" dp)
Miscellaneous	%	0.50	0.50	0.50	0.50	0.50
TOTAL Auxiliary Power	%	7.13	7.35	7.62	7.60	7.87
TOTAL (LEBS) Auxiliary Power	%	4.68	4.97	5.25	5.23	5.50

WASTE STORAGE (30 years):

Ash	acre-ft	1,913	1,693	1,405	1,405	1,405
FGD waste (stabilized)	acre-ft	4,727	4,182	4,165	4,165	4,165

FLUE GAS ANALYSIS (Volumetric):

Carbon Dioxide	%	13.59%	13.59%	14.74%	14.74%	14.74%
Nitrogen	%	73.12%	73.12%	72.74%	72.74%	72.74%
Sulfur Dioxide	%	0.01%	0.01%	0.01%	0.01%	0.01%
Oxygen	%	3.21%	3.21%	1.74%	1.74%	1.74%
Moisture	%	10.08%	10.08%	10.77%	10.77%	10.77%
Flue Gas Molecular Weight	lb/mole	31	31	32	32	32
		100.00%	100.00%	100.00%	100.00%	100.00%

ECONOMIC ANALYSIS:

1992 to Inservice Date	years	6	6	6	6	6
Start of Engineering to COD	months	60	60	60	60	60
Operating Life	years	30	30	30	30	30
AFUDC Rate	%/yr	6.27%	6.27%	6.27%	6.27%	6.27%
Discount Rate	%/yr	5.47%	5.47%	5.47%	5.47%	5.47%
Escalation Rates						
Capital Costs	%/yr	0.00%	0.00%	0.00%	0.00%	0.00%
Overhead & Maintenance	%/yr	0.00%	0.00%	0.00%	0.00%	0.00%
Fuel Costs	%/yr	1.00%	1.00%	1.00%	1.00%	1.00%
SO2 Externalities	%/yr	0.00%	0.00%	0.00%	0.00%	0.00%
NOx & CO2 Externalities	%/yr	0.00%	0.00%	0.00%	0.00%	0.00%
Hours in year at 100% load	hrs	5694	5694	5694	5694	5694
Hours in year at 75% load	hrs	0	0	0	0	0
Hours in year at 50% load	hrs	0	0	0	0	0
Hours in year at 25% load	hrs	0	0	0	0	0
Availability	%/yr	90.00%	90.00%	90.00%	90.00%	90.00%
Levelized Fixed Charge Rate						
%/yr over operating life		10.60%	10.60%	10.60%	10.60%	10.60%
Fixed O&M Costs	\$/kWhr	54.81	56.81	56.81	56.81	56.81
Limestone/Lime reagent cost	\$/ton	15.00	15.00	15.00	15.00	15.00
Limestone/Lime reagent usage	tons/hr	22.79	20.17	20.09	20.09	20.09
Dibasic Acid Cost	\$/ton	600.00	600.00	600.00	600.00	600.00
Dibasic Acid Usage	tons/hr @ current loading conditions	0.00	0.00	0.00	0.00	0.00
Fixative Lime Cost	\$/ton	60.00	60.00	60.00	60.00	60.00
Fixative Lime Usage	tons/hr	0.00	0.00	0.00	0.00	0.00
Ammonia Cost	\$/ton	300	300	300	300	300
Ammonia Usage	ton/hr	0.00	0.00	0.26	0.00	0.00
Water Cost	\$/1000gal	1.00	1.00	1.00	1.00	1.00

Low Emission Boiler System (LEBS) Concept Alternatives

TECHNOLOGY:		1	2	3	4	5
		PC	ASCPC	ASCPC	ASCPC	ASCPC
COMBUSTION SYSTEM:		Low NOx Burners	Low NOx Burners	U-Fired Slagging Burners	Toroidal Vortex Combustor (40" dp)	Toroidal Vortex Combustor (60" dp)
Water Usage		246.58	227.34	227.34	227.34	227.34
ash & sludge disposal						
1992 \$/ton-mile transpt		0.18	0.18	0.18	0.18	0.18
miles to disposal site		20.00	20.00	20.00	20.00	20.00
1992 \$/ton tipping fee		7.00	7.00	7.00	7.00	7.00
1992 \$/ton total cost		10.60	10.60	10.60	10.60	10.60
ash & sludge production	tons/hr	43.44	38.44	38.29	38.29	38.29
other variable O & M costs	\$/MWhr	0.5	0.5	0.5	0.5	0.5
EXTERNALITIES						
Sulfur Dioxide	\$/ton	1500	1500	1500	1500	1500
Nitrogen Oxides	\$/ton	6500	6500	6500	6500	6500
Carbon Dioxide	\$/ton	22	22	22	22	22
fuel cost	\$/MBtu	1.5	1.5	1.5	1.5	1.5
1992 \$/ton, delivered		32.40	32.40	32.40	32.40	32.40
capital costs						
Boiler	\$	59,926,250	71,414,000	76,694,700	62,172,775	62,172,775
Fans	\$	4,564,479	4,320,000	4,320,000	4,928,000	5,156,000
Combustion/Fuel System	\$	3,960,000	3,600,000	3,960,000	7,200,000	7,200,000
Turbine	\$	74,210,000	93,142,000	93,142,000	93,142,000	93,142,000
Air Heater	\$	18,551,010	16,617,000	16,617,000	16,617,000	16,617,000
Particulate Control/Ash Handling Equi	\$	15,723,201	14,084,000	14,084,000	14,084,000	14,084,000
FGD	\$	44,580,882	40,424,670	40,424,670	40,424,670	40,424,670
NOx Control	\$	0	0	15,059,777	0	0
BOP (within LEBS Design Boundary)	\$	52,522,000	49,285,500	49,285,500	49,285,500	49,285,500
BOP (outside LEBS Design Boundary)	\$	134,077,250	125,473,000	125,473,000	125,473,000	125,473,000
Indirects	\$	39,309,000	39,309,000	39,309,000	39,309,000	39,309,000
Contingency	\$	50,897,611	87,757,000	87,757,000	87,757,000	87,757,000
Subtotal (within LEBS Design Boundary)	\$	274,037,822	292,887,170	313,587,647	287,853,945	288,081,945
Total direct, indirect, & contingency c	\$	498,321,684	545,426,170	566,126,647	540,392,945	540,620,945
Capital Cost	\$/kWn	1233	1353	1409	1344	1349
OUTPUT						
annual capacity factor	%/yr	65.00%	65.00%	65.00%	65.00%	65.00%
direct + indirect + contingency	\$	498,322,000	545,426,000	566,127,000	540,393,000	540,621,000
escalation + AFUDC	\$	81,823,000	89,558,000	92,957,000	88,731,000	88,769,000
CAPITAL COSTS						
total capital investment (@ inservice date	\$	580,145,000	634,984,000	659,084,000	629,124,000	629,390,000
levelized fixed charges (over operating lif	\$	61,495,000	67,308,000	69,863,000	66,687,000	66,715,000
FIXED O&M COSTS						
fixed O&M costs	\$	23,842,000	24,712,000	24,712,000	24,712,000	24,712,000
levelized value (over operating life)	\$	23,842,000	24,712,000	24,712,000	24,712,000	24,712,000
VARIABLE O&M COSTS						
limestone/lime reagent	\$	1,752,000	1,550,000	1,544,000	1,544,000	1,544,000
dibasic acid	\$	0	0	0	0	0
fixative lime	\$	0	0	0	0	0
ammonia cost	\$	0	0	393,000	0	0
water	\$	1,264,000	1,165,000	1,165,000	1,165,000	1,165,000

Low Emission Boiler System (LEBS) Concept Alternatives

TECHNOLOGY:		1	2	3	4	5
		PC	ASCPC	ASCPC	ASCPC	ASCPC
COMBUSTION SYSTEM:		Low NOx Burners	Low NOx Burners	U-Fired Slagging Burners	Toroidal Vortex Combustor (40" dp)	Toroidal Vortex Combustor (60" dp)
ash and sludge disposal	\$	1,238,000	1,096,000	1,091,000	1,091,000	1,091,000
other	\$	1,115,000	1,115,000	1,115,000	1,115,000	1,115,000
subtotal	\$	5,369,000	4,926,000	5,308,000	4,915,000	4,915,000
levelized value (over operating life)	\$	5,369,000	4,926,000	5,308,000	4,915,000	4,915,000
EXTERNALITIES						
Sulfur Dioxide	\$	2,968,000	2,627,000	2,616,000	2,616,000	2,616,000
SO2 Levelized Value (over operating life)	\$	2,968,000	2,627,000	2,616,000	2,616,000	2,616,000
Nitrogen Oxides	\$	12,863,000	11,382,000	11,335,000	11,335,000	11,335,000
NOx Levelized Value (over operating life)	\$	12,863,000	11,382,000	11,335,000	11,335,000	11,335,000
Carbon Dioxide	\$	43,713,000	38,680,000	38,523,000	38,523,000	38,523,000
CO2 Levelized Value (over operating life)	\$	43,713,000	38,680,000	38,523,000	38,523,000	38,523,000
Total Externality Costs	\$	59,544,000	52,689,000	52,474,000	52,474,000	52,474,000
FUEL COST						
Fuel costs	\$	\$29,683,000	\$26,265,000	\$26,159,000	\$26,159,000	\$26,159,000
Levelized Value (over operating life)	\$	35,507,000	31,418,000	31,291,000	31,291,000	31,291,000
LEVELIZED REVENUE REQUIREMENTS SUMMARY						
capital charges	\$	61,495,000	67,308,000	69,863,000	66,687,000	66,715,000
fixed O&M costs	\$	23,842,000	24,712,000	24,712,000	24,712,000	24,712,000
variable O&M costs	\$	5,369,000	4,926,000	5,308,000	4,915,000	4,915,000
Sulfur Dioxide	\$	2,968,000	2,627,000	2,616,000	2,616,000	2,616,000
Nitrogen Oxides	\$	12,863,000	11,382,000	11,335,000	11,335,000	11,335,000
Carbon Dioxide	\$	43,713,000	38,680,000	38,523,000	38,523,000	38,523,000
fuel costs	\$	35,507,000	31,418,000	31,291,000	31,291,000	31,291,000
total	\$	185,757,000	181,053,000	183,648,000	180,079,000	180,107,000
LEVELIZED CENTS/KWH SUMMARY						
Capital Charges	¢/kWhr	2.97	3.26	3.39	3.24	3.25
Fixed O&M	¢/kWhr	1.15	1.20	1.20	1.20	1.20
Variable O&M	¢/kWhr	0.26	0.24	0.26	0.24	0.24
Sulfur Dioxide	¢/kWhr	0.14	0.13	0.13	0.13	0.13
Nitrogen Oxides	¢/kWhr	0.62	0.55	0.55	0.55	0.55
Carbon Dioxide	¢/kWhr	2.11	1.87	1.87	1.87	1.88
Fuel Costs	¢/kWhr	1.72	1.52	1.52	1.52	1.52
Total w/o Externalities	¢/kWhr	6.10	6.21	6.37	6.20	6.21
Total	¢/kWhr	8.97	8.77	8.92	8.74	8.77

Add catalyst replacement costs .06
to Case 3 6.43 without externalities
8.98 with externalities

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