Section 3.1

Pulverized Coal-Fired Subcritical Plant
400 MWe

3. PULVERIZED COAL

The market-based pulverized coal power plant design is based on the utilization of pulverized coal feeding a conventional steam boiler and steam turbine. The plant configuration is based on current state-of-the-art technology, commercially available components, and current industry trends. The traditional pulverized coal power plant of the 1970s and 1980s contained reliable equipment with built-in redundancy and several levels of safeguards against unplanned downtime. During the 1980s, the level of redundancy and the design margins were decreased in an effort to reduce cost, yet maintain availabilities in the 82 to 86 percent range. During the 1990s, construction schedules were shortened, design time was decreased by use of "reference plants," and equipment design margins were reduced, all in an effort to enhance the pulverized coal power plant's competitive position. "Reference plants," or modular plant designs, are standard packaged component designs developed by the design firms to enable owners to pick and choose the plant configuration from these pre-designed modules with minimal engineering time.

This section provides technical descriptions and costs for market-based pulverized coal power plants representing state-of-the-art technology, including subcritical, supercritical, and ultra-supercritical operation. A nominal capacity of 400 MWe was used as the basis for design in a typical greenfield application. The subcritical design uses a 2400 psig/1000°F/1000°F single reheat steam power cycle. The steam generator is a natural circulation, wall-fired, subcritical unit arranged with a water-cooled dry-bottom furnace, superheater, reheater, economizer, and air heater components. There are three rows of six burners per each of two walls. All burners are low-NOx type; in addition, overfire air is used to reduce the formation of NOx in the combustion zone.

The supercritical design is based on a 3500 psig/1050°F/1050°F single reheat configuration. This supercritical pulverized coal-fired plant is designed for compliance with national clean air standards anticipated to be in effect in the year 2005.

The ultra-supercritical design is based on a 4500 psig/1100°F/1100°F/1100°F double reheat configuration. This ultra-supercritical pulverized coal-fired plant is designed for compliance with national clean air standards expected to be in effect in the year 2010.

3.1 PULVERIZED COAL-FIRED SUBCRITICAL PLANT - 400 MWe

3.1.1 <u>Design Basis</u>

The design basis of this pulverized coal plant is a nominal 400 MWe subcritical cycle. Support facilities are all encompassing, including rail spur (within the plant fence line), coal handling, (including receiving, crushing, storing, and drying), limestone handling (including receiving, crushing, storing, and feeding), solid waste disposal, flue gas desulfurization, wastewater treatment and equipment necessary for an efficient, available, and completely operable facility. The plant is designed using components suitable for a 30-year life, with provision for periodic maintenance and replacement of critical parts. The plant design and cost estimate are based on equipment manufactured in industrialized nations (United States, Germany, England, etc.) with the standard manufacturer's warranties. The design is based on a referenced design approach to engineering and construction. All equipment is designed and procured in accordance with the latest applicable codes and standards. ASME, ANSI, IEEE, NFPA, CAA, state regulations, and OSHA codes are all adhered to in the design.

3.1.2 <u>Heat and Mass Balance</u>

The steam power cycle is shown schematically in the 100 percent load Heat and Mass Balance diagram (Figure 3.1-1). The diagram shows state points at each of the major components for the conventional plant. Overall performance is summarized in Table 3.1-1, which includes auxiliary power requirements.

The plant uses a 2400 psig/1000°F/1000°F single reheat steam power cycle. The high-pressure (HP) turbine uses 2,734,000 lb/h steam at 2415 psia and 1000°F. The cold reheat flow is 2,425,653 lb/h of steam at 604 psia and 635°F, which is reheated to 1000°F before entering the intermediate-pressure (IP) turbine section.

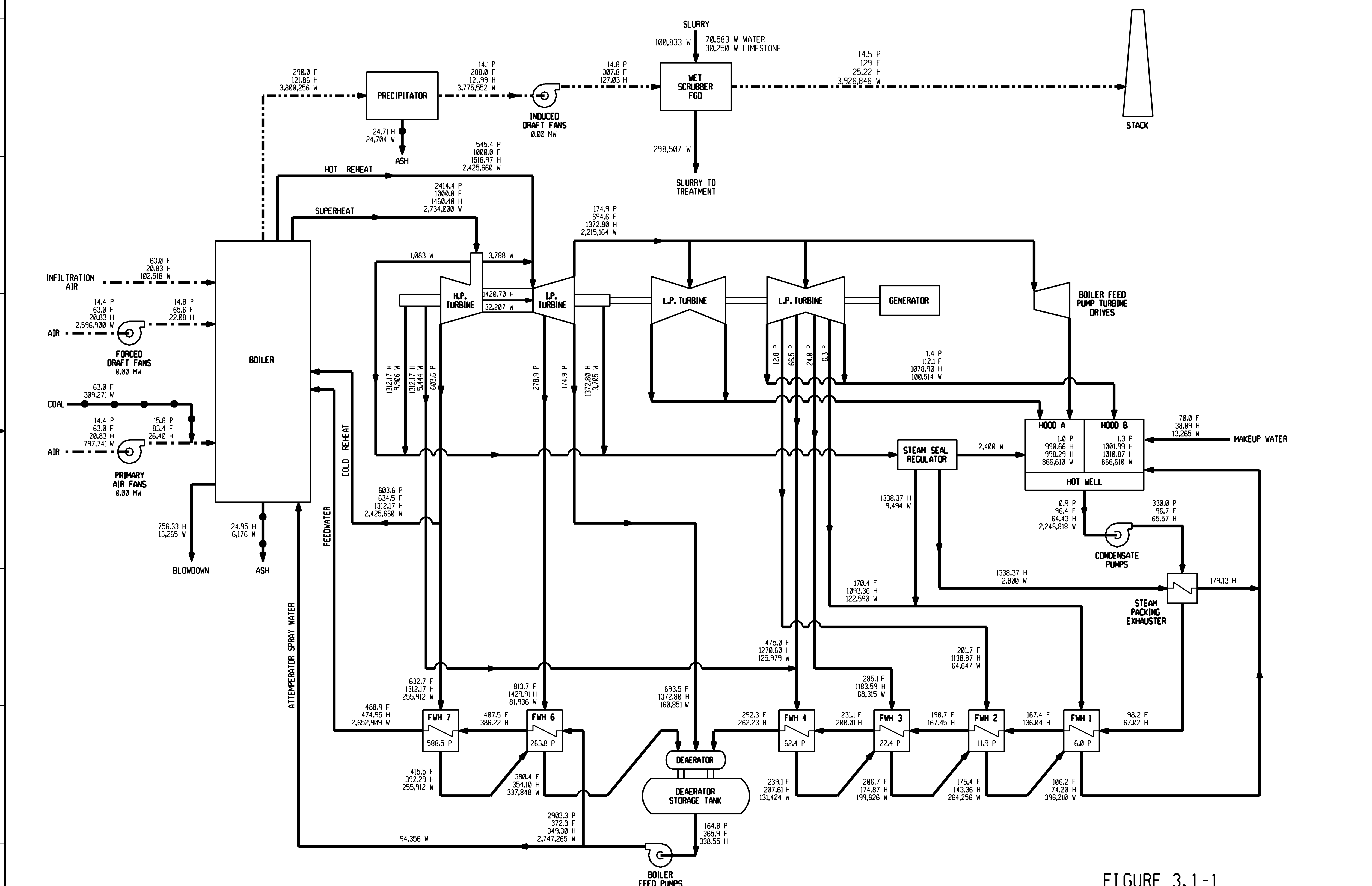

FIGURE 3.1-1

NOTES:

DD

LEGEND

——— (solid line)	CONDENSATE, FEEDWATER, OR STEAM
—●—●—	COAL OR ASH
—·—·—	AIR
—··—··—	FLUE GAS
P	PRESSURE, PSIA
F	TEMPERATURE, °F
H	ENTHALPY, BTU/LBM
W	MASS FLOW, LBM/HR
MWe	POWER, MEGAWATTS ELECTRICAL

SYSTEM PERFORMANCE SUMMARY

GROSS POWER :	429.586	MWe
GENERATOR LOSS :	7.362	MWe
AUXILIARY POWER :	24.742	MWe
NET PLANT POWER :	397.482	MWe
NET PLANT EFFICIENCY :	37.6	%
NET PLANT HEAT RATE :	9,077	Btu/kwh

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REV	DATE	DESCRIPTION	DRAWN	CHECKED	LEAD DESIGNER	ENGINEER	LEAD DISCP ENGR	PROJ ENGR MANAGER	PROJECT MANAGER

STATUS OF DRAWING	DEFINITION
PRELIMINARY	REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.

CONSTRUCTION STATUS

DRAWN BY CLR DATE 12/17/97

CHECKED BY DATE

LEAD DESIGNER DATE

ENGINEER DATE

LEAD DISCIPLINE ENGR. DATE

ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF PE: STATE: LIC. NO.: DATE:

PROJECT ENGINEERING MANAGER

PROJECT MANAGER

PARSONS
PARSONS POWER GROUP INC.
READING / BOSTON / CHARLOTTE / CHATTANOOGA

CLIENT/PROJECT TITLE

CLEAN COAL TECHNOLOGY PROGRAM
PULVERIZED COAL SUBCRITICAL REF PLANT
DEPARTMENT OF ENERGY TASK 22

PLANT HEAT AND MATERIAL BALANCE
100% RATED POWER

SCALE NONE

PARSON'S DWG. NO. MBAC-1-400-314-001

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Table 3.1-1
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, psig	2,400
Throttle Temperature, °F	1,000
Reheat Outlet Temperature, °F	1,000
POWER SUMMARY	
3600 rpm Generator	
GROSS POWER, kWe (Generator terminals)	422,224
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	200
Limestone Handling & Reagent Preparation	850
Pulverizers	1,730
Condensate Pumps	780
Main Feed Pump (Note 1)	8,660
Miscellaneous Balance of Plant (Note 2)	2,000
Primary Air Fans	1,000
Forced Draft Fans	1,000
Induced Draft Fans	4,302
Seal Air Blowers	50
Precipitators	1,100
FGD Pumps and Agitators	3,200
Steam Turbine Auxiliaries	700
Circulating Water Pumps	3,360
Cooling Tower Fans	1,900
Ash Handling	1,550
Transformer Loss	1,020
TOTAL AUXILIARIES, kWe	24,742
Net Power, kWe	397,482
Net Efficiency, % HHV	37.6
Net Heat Rate, Btu/kWh (HHV)	9,077
CONDENSER COOLING DUTY, 10^6 Btu/h	1,740
CONSUMABLES	
As-Received Coal Feed, lb/h	309,270
Sorbent, lb/h	30,250

Note 1 - Driven by auxiliary steam turbine; electric equivalent not included in total.
Note 2 - Includes plant control systems, lighting, HVAC, etc.

Tandem HP, IP, and low-pressure (LP) turbines drive one 3600 rpm hydrogen-cooled generator. The LP turbines consist of two condensing turbine sections. They employ a dual-pressure condenser operating at 2.0 and 2.4 inches Hg at the nominal 100 percent load design point at an ambient wet bulb temperature of 52°F. For the LP turbines, the last-stage bucket length is 30.0 inches, the pitch diameter is 85.0, and the annulus area per end is 55.6 square feet.

The feedwater train consists of six closed feedwater heaters (four LP and two HP), and one open feedwater heater (deaerator). Extractions for feedwater heating, deaerating, and the boiler feed pump are taken from all of the turbine cylinders.

The net plant output power, after plant auxiliary power requirements are deducted, is nominally 397 MWe. The overall plant efficiency is 37.6 percent.

The major features of this plant include the following:

- Boiler feed pumps are steam turbine driven.
- Turbine configuration is a 3600 rpm tandem compound, four-flow exhaust.
- Plant has six stages of closed feedwater heaters plus a deaerator.

3.1.3 Emissions Performance

The plant pollution emission requirements under New Source Performance Standards (NSPS), prior to the Clean Air Act Amendments (CAAA) of 1990, are as shown in Table 3.1-2.

Table 3.1-2
PLANT POLLUTION EMISSION REQUIREMENTS

SOx	90 percent removal
NOx	0.6 lb/10^6 Btu
Particulates	0.03 lb/10^6 Btu
Visibility	20 percent opacity

The 1990 CAAA imposed a two-phase capping of SO_2 emissions on a nationwide basis. For a new greenfield plant, the reduction of SO_2 emissions that would be required depends on possessions or availability of SO_2 allowances by the utility, and on local site conditions. In many cases, Prevention of Significant Deterioration (PSD) Regulations will apply, requiring that Best Available Control Technology (BACT) be used. BACT is applied separately for each site, and results in different values for varying sites. In general, the emission limits set by BACT will be significantly lower than NSPS limits. The ranges specified in Table 3.1-3 will cover most cases.

Table 3.1-3
EMISSION LIMITS SET BY BACT

SOx	92 to 95 percent removal
NOx	0.2 to 0.45 lb/10^6 Btu
Particulates	0.015 to 0.03 lb/10^6 Btu
Visibility	10 to 20 percent opacity

For this study, plant emissions are capped at values shown in Table 3.1-4.

Table 3.1-4
PULVERIZED COAL-FIRED BOILER REFERENCE PLANT EMISSIONS

	Values at Design Condition (65% and 85% Capacity Factor)			
	1b/10^6 Btu	**Tons/year 65%**	**Tons/year 85%**	**lb/MWh**
SO_2	0.34	3,534	4,621	3.13
NOx	0.45	4,622	6,045	4.09
Particulates	0.03	305	400	0.272
CO_2	203.1	2,086,106	2,727,985	1,846

BACT is not applied to the plant described in this report. This report is a base, reference plant design; therefore, the emission limits are set at the industry standard.

3.1.4 Steam Generator and Ancilliaries

The steam generator is a market-based subcritical PC-fired unit plant that is a once-through, wall-fired, balanced draft type unit. It is assumed for the purposes of this study that the power plant is designed to be operated as a base-loaded unit for the majority of its life, with some weekly cycling the last few years. The following brief description is for reference purposes.

3.1.4.1 Scope and General Arrangement

The steam generator is comprised of the following:

- Once-through type boiler
- Water-cooled furnace, dry bottom
- Two-stage superheater
- Reheater
- Startup circuit, including integral separators
- Fin-tube economizer
- Coal feeders and bowl mills (pulverizers)
- Coal and oil burners
- Air preheaters (Ljungstrom type)
- Spray type desuperheater
- Soot blower system
- Forced draft (FD) fans
- Primary air (PA) fans

The steam generator operates as follows:

Feedwater and Steam

The feedwater enters the economizer, recovers heat from the combustion gases exiting the steam generator, and then passes to the water wall circuits enclosing the furnace. After passing through the lower and then the upper furnace circuits in sequence, the fluid passes through the convection enclosure circuits to the primary superheater and then to the secondary superheater. The fluid is mixed in cross-tie headers at various locations throughout this path.

The steam then exits the steam generator enroute to the HP turbine. Steam from the HP turbine returns to the steam generator as cold reheat and returns to the IP turbine as hot reheat.

Air and Combusting Products

Air from the FD fans is heated in the Ljungstrum type air preheaters, recovering heat energy from the exhaust gases on their way to the stack. This air is distributed to the burner windbox as secondary air. A portion of the combustion air is supplied by the PA fans. This air is heated in the Ljungstrum type air preheaters and is used as combustion air to the pulverizers. A portion of the air from the PA fans is routed around the air preheaters and is used as tempering air for the pulverizers. Preheated air and tempering air are mixed at each pulverizer to obtain the desired pulverizer fuel-air mixture outlet temperature.

The pulverized coal and air mixture flows to the coal nozzles at the various elevations of the wall-fired furnace. The hot combustion products rise to the top of the boiler and pass horizontally through the secondary superheater and reheater in succession. The gases then turn downward, passing in sequence through the primary superheater, economizer, and air preheater. The gases exit the steam generator at this point and flow to the precipitator, ID fan, FGD system, and stack.

Fuel Feed

The crushed coal is fed through pairs (three in parallel) of weight feeders and mills (pulverizers). The pulverized coal exits each mill via the coal piping and is distributed to the coal nozzles in the furnace walls.

Ash Removal

The furnace bottom comprises several hoppers, with a clinker grinder under each hopper. The hoppers are of welded steel construction, lined with 9-inch-thick refractory. The hopper design incorporates a water-filled seal trough around the upper periphery for cooling and sealing.

Water and ash discharged from the hopper pass through the clinker grinder to an ash sluice system for conveyance to the ash pond. The description of the balance of the bottom ash handling system is presented in Section 3.1.9. The steam generator incorporates fly ash hoppers under the economizer outlet and air heater outlet.

Burners

A boiler of this capacity will employ approximately 30 coal nozzles arranged in three elevations, divided between the front and rear walls of the furnace. Each burner is designed as a low-NOx configuration, with staging of the coal combustion to minimize NOx formation. In addition, at least one elevation of overfire air nozzles is provided to introduce additional air to cool the rising combustion products to inhibit NOx formation.

Oil-fired pilot torches are provided for each coal burner for ignition and flame stabilization at startup and low loads.

Air Preheaters

Each steam generator is furnished with two vertical inverted Ljungstrom regenerative type air preheaters. These units are driven by electric motors through gear reducers.

Soot Blowers

The soot blowing system utilizes an array of retractable nozzles and lances that travel forward to the blowing position, rotate through one revolution while blowing, and are then withdrawn. Electric motors drive the soot blowers through their cycles. The soot-blowing medium is steam.

3.1.5 Steam Turbine Generator and Auxiliaries

The turbine is tandem compound type, comprised of HP - IP - two LP (double flow) sections, and 30-inch last-stage buckets. The turbine drives a hydrogen-cooled generator. The turbine has DC motor-operated lube oil pumps, and main lube oil pumps, which are driven off the turbine shaft. The turbine is designed for 434,500 kW at generator terminals. The throttle pressure at the design point is 2400 psig at a throttle flow of 2,734,000 lb/h. The exhaust pressure is 2.0/2.4 inch Hg in the dual pressure condenser. There are seven extraction points.

The condenser is two shell, transverse, dual pressure with divided waterbox for each shell.

3.1.6 Coal Handling System

The function of the balance-of-plant coal handling system is to provide the equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to and including the slide gate valves on the outlet of the coal storage silos.

Operation Description

The 6" x 0 bituminous Illinois No. 6 coal is delivered to the site by unit trains of 100-ton rail cars. Each unit train consists of 100, 100-ton rail cars. The unloading will be done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 6" x 0 coal from the feeder is discharged onto a belt conveyor (No. 1). The coal is then transferred to a conveyor (No. 2) that transfers the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron, and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor (No. 3), which transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3" x 0 by the first of two coal crushers. The coal then enters a second crusher that reduces the coal size to 1" x 0. The coal is then transferred by conveyor (No. 4) to the transfer tower. In the transfer tower the coal is routed to the tripper that loads the coal into one of the six silos.

Technical Requirements and Design Basis

- Coal burn rate:
  - Maximum coal burn rate = 309,000 lb/h = 155 tph plus 10% margin = 170 tph (based on the 100% MCR rating for the plant, plus 10% design margin)
  - Average coal burn rate = 262,000 lb/h = 130 tph (based on MCR rate multiplied by an 85% capacity factor)
- Coal delivered to the plant by unit trains:
  - Three (3) unit trains per week at maximum burn rate
  - Two (2) unit trains per week at average burn rate
  - Each unit train shall have 10,000 tons (100-ton cars) capacity
  - Unloading rate = 11 cars/hour (maximum)
  - Total unloading time per unit train = 10 hours (minimum)
  - Conveying rate to storage piles = 900 tph
  - Reclaim rate = 400 tph
- Storage piles with liners, run-off collection, and treatment systems:
  - Active storage = 11,500 tons (72 hours at maximum burn rate)
  - Dead storage = 89,000 tons (30 days at average burn rate)

3.1.7 Limestone Handling and Reagent Preparation System

The function of the limestone handling and reagent preparation system is to receive, store, convey, and grind the limestone delivered to the plant. The scope of the system is from the storage pile up to the limestone feed system. The system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent guarantee point (30 days). Truck roadways, turnarounds, and unloading hoppers are included in this reference plant design.

Operation Description

For the purposes of this conceptual design, limestone will be delivered to the plant by 25-ton trucks.

The limestone is unloaded onto a storage pile located above vibrating feeders. The limestone is fed onto belt conveyors via vibrating feeders and then to a day bin equipped with vent filters. The day bin supplies a 100 percent capacity size ball mill via a weigh feeder. The wet ball mill accepts the limestone and grinds the limestone to 90 to 95 percent passing 325 mesh (44 microns). Water is added at the inlet to the ball mill to create a limestone slurry. The reduced limestone slurry is then discharged into a mill slurry tank. Mill recycle pumps, two per tank, pump the limestone water slurry to an assembly of hydroclones and distribution boxes. The slurry is classified into several streams, based on suspended solids content and size distribution.

The hydroclone underflow is directed back to the mill for further grinding. The hydroclone overflow is routed to a reagent storage tank. Reagent distribution pumps direct slurry from the tank to the absorber module.

Technical Requirements and Design Basis

- Limestone usage rate:
  - Maximum limestone usage rate = 30,250 lb/h = 15.15 tph plus 10% margin = 16.6 tph (based on operating at MCR; 155 tph firing rate for design coal and 80% $CaCO_3$ in the limestone)
  - Average limestone usage rate = 25,700 lb/h = 13 tph (based on maximum limestone usage rate multiplied by 85% capacity factor)
- Limestone delivered to the plant by 25-ton dump trucks
- Total number of trucks per day = 16
- Total unloading time per day = 4 hours
- Total time, interval per truck = 15 minutes/truck

- Receiving hopper capacity = 35 tons
- Limestone received = 1" x 0
- Limestone storage capacity = 12,000 tons (30 days supply at maximum burn rate)
- Storage pile size = 180 ft x 90 ft x 40 ft high
- Day bin storage = 300 tons (16-hour supply at maximum burn rate)
- Conveying rate to day bins = 150 tph
- Weigh feeder/limestone ball mill capacity, each = 17 tph (based on 24 hours per day of grinding operations)
- Mill slurry tank capacity = 10,000 gallons
- Mill recycle pump capacity = 600 gpm, each of two pumps, two per mill
- No. of hydroclones = 1 assembly, rated at 600 gpm
- Reagent storage tank capacity = 200,000 gallons, 1 tank
- Reagent distribution pump capacity = 300 gpm, each of two pumps

3.1.8 Emissions Control Systems

3.1.8.1 Flue Gas Desulfurization (FGD) System

The function of the FGD system is to scrub the boiler exhaust gases to remove 92 percent of the SO_2 content prior to release to the environment. The scope of the FGD system is from the outlet of the induced draft (ID) fans to the stack inlet. The system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent design point (30 days).

Operation Description

The flue gas exiting the air preheater section of the boiler passes through a pair of electrostatic precipitator units, then through the ID fans and into the one 100 percent capacity absorber module. The absorber module is designed to operate with counter-current flow of gas and reagent. Upon entering the bottom of the absorber vessel, the gas stream is subjected to an initial quenching spray of reagent. The gas flows upward through a tray, which provides enhanced contact between gas and reagent. Multiple sprays above the tray maintain a consistent reagent concentration in the tray zone. Continuing upward, the reagent laden gas passes through several levels of moisture separators. These will consist of chevron-shaped vanes that direct the gas flow through several abrupt changes in direction, separating the entrained droplets of liquid by inertial effects. The scrubbed and dried flue gas exits at the top of the absorber vessel and is routed to the plant stack. The FGD system for this reference plant is designed to continuously remove 92 percent of the SO_2.

The scrubbing slurry falls to the lower portion of the absorber vessel, which contains a large inventory of liquid. Oxidation air is added to promote the oxidation of calcium sulfate, contained in the slurry, to calcium sulfate (gypsum). Multiple agitators operate continuously to prevent settling of solids and enhance mixture of the oxidation air and the slurry. Recirculation pumps recirculate the slurry from the lower portion of the absorber vessel to the spray level. Spare recirculation pumps are provided to ensure availability of the absorber.

The absorber chemical equilibrium is maintained by continuous makeup of fresh reagent, and blowdown of spent reagent via the bleed pumps. A spare bleed pump is provided to ensure availability of the absorber. The spent reagent is routed to the byproduct dewatering system. The circulating slurry is monitored for pH and density.

This FGD system is designed for “wet stack” operation. Scrubber bypass or reheat, which may be utilized at some older facilities to ensure the exhaust gas temperature is above the saturation temperature, is not employed in this reference plant design because new scrubbers have improved mist eliminator efficiency, and detailed flow modeling of the flue interior enables the placement of gutters and drains to intercept moisture that may be present and convey it to a drain. Consequently, raising the exhaust gas temperature is not necessary.

Technical Requirements and Design Basis

- Number and type of absorber modules = One, 100% capacity, counter-current tower design, including quench, absorption and moisture separation zones, recirculated slurry inventory in lower portion of absorber vessel

- Slurry recirculation pumps = Four at 33% capacity each
- Slurry bleed pumps = Two at 100% capacity each
- Absorber tank agitator = Four each with 20 hp motor
- Oxidation air blowers = Two at 100% capacity each

3.1.8.2 Byproduct Dewatering

The function of the byproduct dewatering system is to dewater the bleed slurry from the FGD absorber modules. The dewatering process selected for this plant is a gypsum stacking system. The scope of the system is from the bleed pump discharge connections to the gypsum stack. The system is designed to support operation on a 20-year life cycle.

<u>Operation Description</u>

The recirculating reagent in the FGD absorber vessel accumulates dissolved and suspended solids on a continuous basis as byproducts from the SO_2 absorption reactions process. Maintenance of the quality of the recirculating reagent requires that a portion be withdrawn and replaced by fresh reagent. This is accomplished on a continuous basis by the bleed pumps pulling off spent reagent and the reagent distribution pumps supplying fresh reagent to the absorber.

Gypsum (calcium sulfate) is produced by the injection of oxygen into the calcium sulfite produced in the absorber tower sump. The gypsum slurry, at approximately 15 percent solids, is pumped to a gypsum stacking area. A starter dike is constructed to form a settling pond so that the 15 percent solid gypsum slurry is pumped to the sedimentation pond, where the gypsum particles settle and the excess water is decanted and recirculated back to the plant through the filtrate system. A gypsum stacking system allows for the possibility of a zero discharge system. The stacking area consists of approximately 42 acres, enough storage for 20 years of operation. The gypsum stack is rectangular in plan shape, and is divided into two sections. This allows one section to drain while the other section is in use. There is a surge pond around the perimeter of the stacking area, which accumulates excess water for recirculation back to the plant. The stacking area includes all necessary geotechnical liners and construction to protect the environment.

3.1.8.3 Precipitator

The flue gas discharged from the boiler (air preheater) is directed through an electrostatic precipitator array comprised of two rigid frame single-stage units. Each precipitator unit is divided into five field sections, each in turn containing three cells. Each cell contains a number of gas passages comprised of discharge electrodes, collecting plates, and ash hoppers supported by a rigid steel casing. Each cell and ash hopper is provided with a rapping system, which periodically provides a mechanical shock to the unit to cause the fly ash particles to drop into the hopper, and then out into the collection piping. The precipitators are provided with necessary electrical power and control devices, inlet gas distribution devices, insulators, inlet and outlet nozzles, expansion joints, and other items as required.

3.1.9 Balance of Plant

3.1.9.1 Condensate and Feedwater

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser and the LP feedwater heaters. Each system consists of one main condenser; two 50 percent capacity, variable speed electric motor-driven vertical condensate pumps; one gland steam condenser; four LP heaters; and one deaerator with storage tank.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided downstream of the gland steam condenser to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

LP feedwater heaters 1 and 2 are 50 percent capacity, parallel flow and are located in the condenser neck. All remaining feedwater heaters are 100 percent capacity shell and U-tube heat exchangers. Each LP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the condenser. Normal drain levels in the heaters are controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

The function of the feedwater system is to pump the feedwater from the deaerator storage tank through the HP feedwater heaters to the economizer. One turbine-driven boiler feed pump sized at 100 percent capacity is provided to pump feedwater through the HP feedwater heaters. The pump is provided with inlet and outlet isolation valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by automatic recirculation valves, which are a combination check valve in the main line and in the bypass, bypass control valve, and flow sensing element. The suction of the boiler feed pump is equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Each HP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. Feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the deaerator. Normal drain level in the heaters is controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

The deaerator is a horizontal, spray tray type with internal direct contact stainless steel vent condenser and storage tank. The boiler feed pump turbine is driven by main steam up to 60 percent plant load. Above 60 percent load, extraction from the IP turbine exhaust provides steam to the boiler feed pump steam turbines.

3.1.9.2 Main, Reheat, and Extraction Steam Systems

Main and Reheat Steam

The function of the main steam system is to convey main steam from the boiler superheater outlet to the HP turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the boiler reheater and from the boiler reheater outlet to the IP turbine stop valves.

Main steam at approximately 2400 psig/1000°F exits the boiler superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed in a single line feeding the HP turbine. A branch line off the main steam line feeds the boiler feed pump turbine during unit operation up to approximately 60 percent load.

Cold reheat steam at approximately 585 psig/635°F exits the HP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the boiler reheater. Hot reheat steam at approximately 530 psig/1000°F exits the boiler reheater through a motor-operated gate valve and is routed to the IP turbine. A branch connection from the cold reheat piping supplies steam to feedwater heater 7.

Extraction Steam

The function of the extraction steam system is to convey steam from turbine extraction points through the following routes:

- From HP turbine exhaust (cold reheat) to heater 7
- From IP turbine extraction to heater 6 and the deaerator
- From LP turbine extraction to heaters 1, 2, 3 and 4

The turbine is protected from overspeed on turbine trip, from flash steam reverse flow from the heaters through the extraction piping to the turbine. This protection is provided by positive closing, balanced disc non-return valves located in all extraction lines except the lines to the LP feedwater heaters in the condenser neck. The extraction non-return valves are located only in horizontal runs of piping and as close to the turbine as possible.

The turbine trip signal automatically trips the non-return valves through relay dumps. The remote manual control for each heater level control system is used to release the non-return valves to normal check valve service when required to restart the system.

3.1.9.3 Circulating Water System

It is assumed that the plant is serviced by a river of capacity and quality for use as makeup cooling water with minimal pretreatment. All filtration and treatment of the circulating water are conducted on site. A mechanical draft, concrete, rectangular, counter-flow cooling tower is provided for the circulating water heat sink. Two 50 percent circulating water pumps are provided. The circulating water system provides cooling water to the condenser and the auxiliary cooling water system.

The auxiliary cooling water system is a closed-loop system. Plate and frame heat exchangers with circulating water as the cooling medium are provided. This system provides cooling water to the lube oil coolers, turbine generator, boiler feed pumps, etc. All pumps, vacuum breakers, air release valves, instruments, controls, etc. are included for a complete operable system.

3.1.9.4 Ash Handling

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing of the fly ash and bottom ash produced on a daily basis by the boiler. The scope of the system is from the precipitator hoppers, air heater hopper collectors, and bottom ash hoppers to the ash pond (for bottom ash) and truck filling stations (for fly ash). The system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent guarantee point (15 days or more).

<u>Operation Description</u>

The fly ash collected in the precipitators and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system using low-pressure air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

The bottom ash from the boiler is fed into a clinker grinder. The clinker grinder is provided to break up any clinkers that may form. From the clinker grinders the bottom ash is discharged via a hydro-ejector and ash discharge piping to the ash pond.

Ash from the economizer hoppers and pyrites (rejected from the coal pulverizers) is conveyed by hydraulic means (water) to the economizer/pyrites transfer tank. This material is then sluiced, on a periodic basis, to the ash pond.

Technical Requirements and Design Basis

- Bottom ash and fly ash rates:
  - Bottom ash generation rate, 6,000 lb/h = 3 tph
  - Fly ash generation rate, 24,000 lb/h = 12 tph
- Bottom ash:
  - Clinker grinder capacity = 5 tph
  - Conveying rate to ash pond = 5 tph
- Fly ash:
  - Collection rate = 12 tph
  - Conveying rate from precipitator and air heaters = 11.7 tph
  - Fly ash silo capacity = 900 tons (72-hour storage)
  - Wet unloader capacity = 30 tph

3.1.9.5 Ducting and Stack

One stack is provided with a single fiberglass-reinforced plastic (FRP) liner. The stack is constructed of reinforced concrete, with an outside diameter at the base of 70 feet. The stack is 480 feet high for adequate particulate dispersion. The stack has one 19.5-foot-diameter FRP stack liner.

3.1.9.6 Waste Treatment

An onsite water treatment facility will treat all runoff, cleaning wastes, blowdown, and backwash to within the U.S. Environmental Protection Agency (EPA) standards for suspended solids, oil and grease, pH, and miscellaneous metals. Waste treatment equipment will be housed in a separate building. The waste treatment system consists of a water collection basin, three raw waste pumps, an acid neutralization system, an oxidation system, flocculation, clarification/ thickening, and sludge dewatering. The water collection basin is a synthetic-membrane-lined earthen basin, which collects rainfall runoff, maintenance cleaning wastes, and backwash flows.

The raw waste is pumped to the treatment system at a controlled rate by the raw waste pumps. The neutralization system neutralizes the acidic wastewater with hydrated lime in a two-stage system, consisting of a lime storage silo/lime slurry makeup system with 50-ton lime silo, a 0-1,000 lb/h dry lime feeder, a 5,000-gallon lime slurry tank, slurry tank mixer, and 25 gpm lime slurry feed pumps.

The oxidation system consists of a 50 scfm air compressor, which injects air through a sparger pipe into the second-stage neutralization tank. The flocculation tank is fiberglass with a variable speed agitator. A polymer dilution and feed system is also provided for flocculation. The clarifier is a plate-type, with the sludge pumped to the dewatering system. The sludge is dewatered in filter presses and disposed off-site. Trucking and disposal costs are included in the cost estimate. The filtrate from the sludge dewatering is returned to the raw waste sump.

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water will be provided. A 200,000-gallon storage tank will provide a supply of No. 2 fuel oil used for startup and for a small auxiliary boiler. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

3.1.10 Accessory Electric Plant

The accessory electric plant consists of all switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, and wire and cable. It also includes the main power transformer, required foundations, and standby equipment.

3.1.11 Instrumentation and Control

An integrated plant-wide control and monitoring system (DCS) is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor (CRT) and keyboard units. The CRT/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability. The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual, with operator selection of modular automation routines available.

3.1.12 Buildings and Structures

A soil bearing load of 5,000 lb/ft^2 is used for foundation design. Foundations are provided for the support structures, pumps, tanks, and other plant components. The following buildings are included in the design basis:

- Steam turbine building
- Boiler building
- Administration and service building
- Makeup water and pretreatment building
- Pump house and electrical equipment building
- Fuel oil pump house
- Continuous emissions monitoring building
- Coal crusher building
- River water intake structure
- Guard house
- Runoff water pump house
- Industrial waste treatment building
- FGD system buildings

3.1.13 Equipment List - Major

ACCOUNT 1 COAL AND SORBENT HANDLING

ACCOUNT 1A COAL RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	200 ton	2
2	Feeder	Vibratory	450 tph	2
3	Conveyor No. 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor No. 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	225 tph	2
8	Conveyor No. 3	48" belt	450 tph	1
9	Crusher Tower	N/A	450 tph	1
10	Coal Surge Bin w/ Vent Filter	Compartment	450 ton	1
11	Crusher	Granulator reduction	6"x0 - 3"x0	1
12	Crusher	Impactor reduction	3"x0 - 1¼"x0	1
13	As-Fired Coal Sampling System	Swing hammer	450 tph	2
14	Conveyor No. 4	48" belt	450 tph	1
15	Transfer Tower	N/A	450 tph	1
16	Tripper	N/A	450 tph	1
17	Coal Silo w/ Vent Filter and Slide Gates	N/A	600 ton	6

ACCOUNT 1B LIMESTONE RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Truck Unloading Hopper	N/A	35 ton	2
2	Feeder	Vibratory	115 tph	2
3	Conveyor No. 1	30" belt	115 tph	1
5	Limestone Day Bin		350 tons	1

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A COAL PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Feeder	Gravimetric	40 tph	6
2	Pulverizer	B&W type MPS-75	40 tph	6

ACCOUNT 2B LIMESTONE PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Bin Activator		17 tph	1
2	Weigh Feeder	Gravimetric	17 tph	1
3	Limestone Ball Mill	Rotary	17 tph	1
4	Mill Slurry Tank with Agitator		10,000 gal	1
5	Mill Recycle Pumps	Horizontal centrifugal	600 gpm	2
6	Hydroclones	Radial assembly	600 gpm	1
7	Distribution Box	3-way		2
8	Reagent Storage Tank with Agitator	Field erected	200,000 gal	1
9	Reagent Distribution Pumps	Horizontal centrifugal	300 gpm	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER

Equipment No.	Description	Type	Design Condition	Qty.
1	Cond. Storage Tank	Field fab.	250,000 gal	1
2	Surface Condenser	Two shell, transverse tubes	2,250 x 10^6 lb/h 2.0/2.4 in. Hg	1
3	Cond. Vacuum Pumps	Rotary water sealed	2,500/25 scfm	2
4	Condensate Pumps	Vert. canned	2,500 gpm @ 800 ft	2
5	LP Feedwater Heater 1A/1B	Horiz. U tube	1,124,409 lb/h	2
6	LP Feedwater Heater 2A/2B	Horiz. U tube	1,124,409 lb/h	2
7	LP Feedwater Heater 3	Horiz. U tube	2,248,818 lb/h	1
8	LP Feedwater Heater 4	Horiz. U tube	2,248,818 lb/h	1
9	Deaerator and Storage Tank	Horiz. spray type	2,248,818 lb/h	1
10	Boiler Feed Pump/ Turbine	Barrel type, multi-staged, centr.	6,190 gpm @ 7,200 ft	1
11	Startup Boiler Feed Pump	Barrel type, multi-staged, centr.	1,550 gpm @ 7,200 ft	1
12	HP Feedwater Heater 6	Horiz. U tube	2,652,909 lb/h	1
13	HP Feedwater Heater 7	Horiz. U tube	2,652,909 lb/h	1

ACCOUNT 3B MISCELLANEOUS SYSTEMS

Equipment No.	Description	Type	Design Condition	Qty.
1	Auxiliary Boiler	Shop fab. water tube	400 psig, 650°F	1
2	Fuel Oil Storage Tank	Vertical, cylindrical	200,000 gal	1
3	Fuel Oil Unloading Pump	Gear	150 ft, 800 gpm	1
4	Fuel Oil Supply Pump	Gear	400 ft, 80 gpm	2
5	Service Air Compressors	Rotary screw	100 psig, 800 cfm	3
6	Inst. Air Dryers	Duplex, regenerative	400 cfm	1
7	Service Water Pumps	S.S., double suction	100 ft, 7,000 gpm	2
8	Closed Cycle Cooling Heat Exch.	Shell & tube	50% cap. each	2
9	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	50 ft, 700 gpm	2
10	Fire Service Booster Pump	Two-stage cent.	250 ft, 700 gpm	1
11	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
12	Riverwater Makeup Pumps	S.S., single suction	100 ft, 5,750 gpm	2
13	Filtered Water Pumps	S.S., single suction	200 ft, 220 gpm	2
14	Filtered Water Tank	vertical, cylindrical	15,000 gal	1
15	Makeup Demineralizer	Anion, cation, and mixed bed	100 gpm	2
16	Liquid Waste Treatment System	-	10 years, 25-hour storm	1
17	Condenste Demineralizer	-	1,600 gpm	1

ACCOUNT 4 PFBC BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Qty.
1	Boiler with Air Heater	Natural circ., wall-fired	550 MWe, 3,621,006 pph steam at 2660 psig/1000°F	1
2	Primary Air Fan	Axial	398,870 pph, 87,020 acfm, 39" WG, 650 hp	2
3	FD Fan	Cent.	1,298,450 pph, 283,260 acfm, 11" WG, 650 hp	2
4	ID Fan	Cent.	1,887,776 pph, 582,650 acfm, 33" WG, 4,100 hp	2

ACCOUNT 5 FLUE GAS CLEANUP

ACCOUNT 5A PARTICULATE CONTROL

Equipment No.	Description	Type	Design Condition	Qty.
1	Electrostatic Precipitator	Rigid frame, single stage	1,900,128 pph, 392,000 ft^2 plate area	2

ACCOUNT 5B FLUE GAS DESULFURIZATION

Equipment No.	Description	Type	Design Condition	Qty.
1	Absorber Module	Spray/tray	1,165,300 acfm	1
2	Recirculation Pumps	Horizontal centrifugal	35,000 gpm	4
3	Bleed Pumps	Horizontal centrifugal	750 gpm	2
4	Oxidation Air Blowers	Centrifugal	6,500 scfm, 35 psia	2
5	Agitators	Side entering	25 hp motor	6

Byproduct Dewatering

Equipment No.	Description	Type	Design Condition	Qty.
6	Gypsum Stacking Pump	Horizontal centrifugal	750 gpm	2
7	Gypsum Stacking Area		42 acres	1
8	Process Water Return Pumps	Vertical centrifugal	500 gpm	2
9	Process Water Return Storage Tank	Vertical, lined	200,000 gal	1
10	Process Water Recirculation Pumps	Horizontal centrifugal	500 gpm	2

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Not Applicable

ACCOUNT 7 WASTE HEAT BOILER, DUCTING AND STACK

Equipment No.	Description	Type	Design Condition	Qty.
1	Stack	Reinf. concrete, one FRP flue	60 ft/sec exit velocity 480 ft high x 19.5 ft dia. (flue)	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty.
1	550 MW Turbine Generator	TC4F30	2400 psig, 1000°F/1000°F	1
2	Bearing Lube Oil Coolers	Shell & tube	-	2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop	-	1
4	Control System	Electro-hydraulic	1600 psig	1
5	Generator Coolers	Shell & tube	-	2
6	Hydrogen Seal Oil System	Closed loop	-	1
7	Generator Exciter	Solid state brushless	-	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Cooling Tower	Mech draft	222,000 gpm	1
2	Circ. Water Pumps	Vert. wet pit	111,000 gpm @ 95 ft	2

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

ACCOUNT 10A BOTTOM ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Economizer Hopper (part of Boiler scope of supply)			4
2	Bottom Ash Hopper (part of Boiler scope of supply)			2
3	Clinker Grinder		5 tph	2
4	Pyrites Hopper (part of Pulverizer scope of supply included with Boiler)			6
5	Hydroejectors			13
6	Economizer/Pyrites Transfer Tank		38,000 gal	1
7	Ash Sluice Pumps	Vertical, wet pit	1,500 gpm	1
8	Ash Seal Water Pumps	Vertical, wet pit	1,500 gpm	1

ACCOUNT 10B FLY ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Precipitator Hopper (part of Precipitator scope of supply)			24
2	Air Heater Hopper (part of Boiler scope of supply)			10
3	Air Blower		1,750 scfm	2
4	Fly Ash Silo	Reinf. concrete	860 tons	1
5	Slide Gate Valves			2
6	Unloader		100 tph	1
7	Telescoping Unloading Chute			1

3.1.14 Conceptual Capital Cost Estimate Summary

The summary of the conceptual capital cost estimate for the 400 MW subcritical PC plant is shown in Table 3.1-5. The estimate summarizes the detail estimate values that were developed consistent with Section 9, "Capital and Production Cost and Economic Analysis." The detail estimate results are contained in Appendix E.

Examination of the values in the table reveal several relationships that are subsequently addressed. The relationship of the equipment cost to the direct labor cost varies for each account. This variation is due to many factors including the level of fabrication performed prior to delivery to the site, the amount of bulk materials represented in the equipment or material cost column, and the cost basis for the specific equipment (degree of field fabrication required for items too large to ship to the site in one or several major pieces). Also note that the total plant cost ($/kW) values are all determined on the basis of the total plant net output. This will be more evident as other technologies are compared. One significant change compared to the other plants is that, unlike all of the other technologies, all of the power is generated from a single source, the steam turbine. As a result, the economy of scale influence is greatest for this plant.

Table 3.1-5

Client: DEPARTMENT OF ENERGY
Project: Market Based Advanced Coal Power Systems
Report Date: 14-Aug-98 07:54 AM

TOTAL PLANT COST SUMMARY

Case: Subcritical PC
Plant Size: 397.5 MW,net
Estimate Type: Conceptual
Cost Base (Jan) 1998 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	6,997	2,063	5,331	373		**$14,764**	1,181		3,189	**$19,134**	48
2	COAL & SORBENT PREP & FEED	8,789		2,748	192		**$11,729**	938		2,533	**$15,201**	38
3	FEEDWATER & MISC. BOP SYSTEMS	15,953		6,963	487		**$23,403**	1,872		6,002	**$31,276**	79
4	PC BOILER & ACCESSORIES											
4.1	PC Boiler	46,861		19,453	1,362		**$67,676**	5,414		7,309	**$80,400**	202
4.2	Open											
4.3	Open											
4.4-4.9	Boiler BoP (w/FD & ID Fans)	3,260		1,074	75		**$4,410**	353		476	**$5,239**	13
	SUBTOTAL 4	*50,122*		*20,528*	*1,437*		***$72,086***	*5,767*		*7,785*	***$85,639***	*215*
5	FLUE GAS CLEANUP	34,039		18,650	1,306		**$53,995**	4,320		5,831	**$64,146**	161
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A		N/A								
6.2-6.9	Combustion Turbine Accessories											
	SUBTOTAL 6											
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A		N/A								
7.2-7.9	HRSG Accessories, Ductwork and Stack	9,803	289	7,270	509		**$17,871**	1,430		2,992	**$22,293**	56
	SUBTOTAL 7	*9,803*	*289*	*7,270*	*509*		***$17,871***	*1,430*		*2,992*	***$22,293***	*56*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	30,684		5,055	354		**$36,093**	2,887		3,898	**$42,879**	108
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	11,740	358	6,439	451		**$18,988**	1,519		3,531	**$24,037**	60
	SUBTOTAL 8	*42,424*	*358*	*11,494*	*805*		***$55,081***	*4,406*		*7,429*	***$66,916***	*168*
9	COOLING WATER SYSTEM	7,623	3,966	7,208	505		**$19,301**	1,544		3,718	**$24,563**	62
10	ASH/SPENT SORBENT HANDLING SYS	6,025	80	11,018	771		**$17,893**	1,431		2,930	**$22,254**	56
11	ACCESSORY ELECTRIC PLANT	9,095	2,830	7,720	540		**$20,185**	1,615		3,574	**$25,373**	64
12	INSTRUMENTATION & CONTROL	6,037		5,006	350		**$11,393**	911		1,917	**$14,222**	36
13	IMPROVEMENTS TO SITE	1,871	1,076	3,747	262		**$6,957**	557		2,254	**$9,767**	25
14	BUILDINGS & STRUCTURES		15,586	18,701	1,309		**$35,597**	2,848		9,611	**$48,055**	121
	TOTAL COST	**$198,778**	**$26,247**	**$126,383**	**$8,847**		**$360,255**	**$28,820**		**$59,765**	**$448,840**	**1129**

Section 3.2

Pulverized Coal-Fired Supercritical Plant
400 MWe

3.2 PULVERIZED COAL-FIRED SUPERCRITICAL PLANT - 400 MWe

3.2.1 Introduction

This 400 MWe single unit (nominal) pulverized coal-fired electric generating station serves as a reference case for comparison with a series of Clean Coal Technology greenfield power generating stations. The principal design parameters characterizing this plant were established to be representative of a state-of-the-art facility, balancing economic and technical factors.

3.2.2 Heat and Mass Balance

Overall performance for the entire plant is summarized in Table 3.2-1, which includes auxiliary power requirements. The heat and mass balance is based on the use of Illinois No. 6 coal as fuel. The steam power cycle is shown schematically in the 100 percent load Heat and Mass Balance diagram, Figure 3.2-1. The performance presented in this heat balance reflects current state-of-the art turbine adiabatic efficiency levels, boiler performance, and wet limestone FGD system capabilities. The diagram shows state points at each of the major components for this conceptual design.

The steam cycle used for this case is based on a 3500 psig/1050°F/1050°F single reheat configuration. The HP turbine uses 2,699,000 lb/h steam at 3515 psia and 1050°F. The cold reheat flow is 2,176,000 lb/h of steam at 622 psia and 587°F, which is reheated to 1050°F before entering the IP turbine section.

The turbine generator is a single machine comprised of tandem HP, IP, and LP turbines driving one 3,600 rpm hydrogen-cooled generator. The turbine exhausts to a dual-pressure condenser operating at 1.5 and 2.0 inches Hga, low- and high-pressure shells, respectively, at the nominal 100 percent load design point. For the four-flow LP turbines, the last-stage bucket length is 30 inches, the pitch diameter is 85.0 inches, and the annulus area per end is 55.6 square feet.

Table 3.2-1
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, psig	3,500
Throttle Temperature, °F	1,050
Reheat Outlet Temperature, °F	1,050
POWER SUMMARY (Gross Power at Generator Terminals, kWe)	427,100
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	210
Limestone Handling & Reagent Preparation	810
Pulverizers	1,650
Condensate Pumps	520
Main Feed Pump (Note 1)	11,850
Miscellaneous Balance of Plant (Note 2)	2,050
Primary Air Fans	950
Forced Draft Fan	950
Induced Draft Fan	6,977
Baghouse	100
SCR	80
FGD Pumps and Agitators	2,950
Steam Turbine Auxiliaries	700
Circulating Water Pumps	3,090
Cooling Tower Fans	1,750
Ash Handling	1,480
Transformer Loss	1,020
TOTAL AUXILIARIES, kWe	25,277
Net Power, kWe	401,823
Net Efficiency, % HHV	39.9
Net Heat Rate, Btu/kWh (HHV)	8,568
CONDENSER COOLING DUTY, 10^6 Btu/h	1,584
CONSUMABLES	
As-Received Coal Feed, lb/h	295,100
Sorbent (Limestone)Feed, lb/h	30,060
Ammonia feed, lb/h	1,290

Note 1 **-** Driven by auxiliary steam turbine; electric equivalent not included in total.

Note 2 **-** Includes plant control systems, lighting, HVAC, etc.

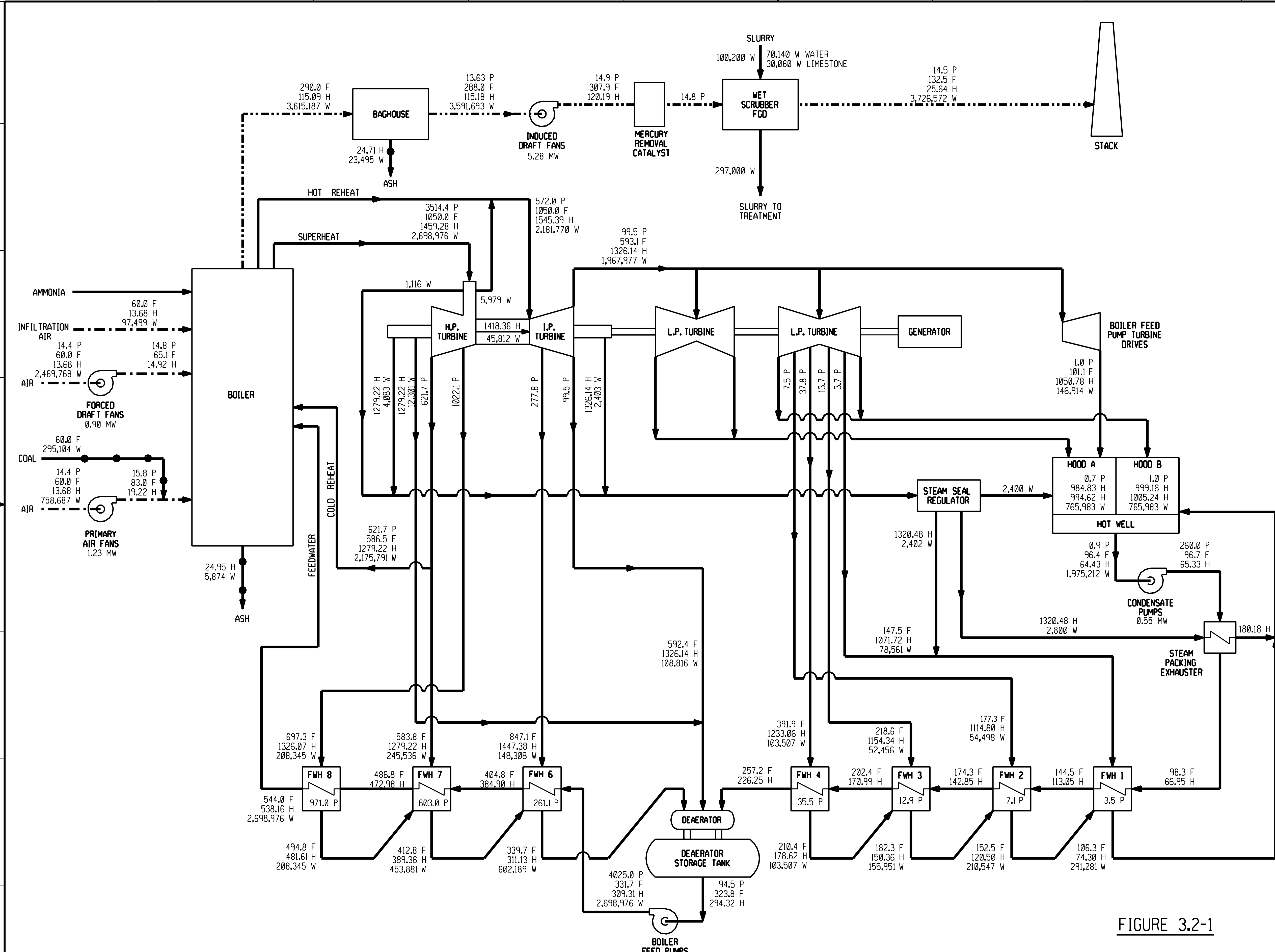

FIGURE 3.2-1

NOTES:

DD

LEGEND

(solid line)	CONDENSATE, FEEDWATER, OR STEAM
(line with dots)	COAL OR ASH
(dash-dot line)	AIR
(dash-dot-dot line)	FLUE GAS
P	PRESSURE, PSIA
F	TEMPERATURE, °F
H	ENTHALPY, BTU/LBM
W	MASS FLOW, LBM/HR
MWe	POWER, MEGAWATTS ELECTRICAL

SYSTEM PERFORMANCE SUMMARY

GROSS POWER :	434.5 MWe
GENERATOR LOSS :	7.4 MWe
AUXILIARY POWER :	25.28 MWe
NET PLANT POWER :	401.8 MWe
NET PLANT EFFICIENCY :	39.9 %
NET PLANT HEAT RATE :	8568 Btu/kwh

REV | DATE | DESCRIPTION | DRAWN | CHECKED | LEAD DESIGNER | ENGINEER | PROJ ENGR ENGINEER | PROJECT MANAGER

STATUS OF DRAWING	DEFINITION
PRELIMINARY	REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.

CONSTRUCTION STATUS

DRAWN BY CLR DATE

CHECKED BY DATE

LEAD DESIGNER DATE

ENGINEER DATE

LEAD DISCIPLINE ENGR. DATE

ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF PE: STATE: LIC. NO.: DATE:

PROJECT ENGINEERING MANAGER

PROJECT MANAGER

PARSONS

PARSONS POWER GROUP INC.

READING / BOSTON / CHARLOTTE / CHATTANOOGA

CLIENT/PROJECT TITLE

CLEAN COAL TECHNOLOGY PROGRAM

PULVERIZED COAL SUPERCRITICIAL REF PLANT

DEPARTMENT OF ENERGY TASK 22

PLANT HEAT AND MATERIAL BALANCE

100% RATED POWER

SCALE NONE

PARSON'S DWG. NO. MBAC-1-400-314-002

REV A

ARCH | HVAC | I & C | ELECT | MECH | CIVIL | STRUC

PPGI-FILE: PPGI-DATE: PC-SC0ID / PCSC0IDT

432006.8436104.GRA
432006.8436104.NOD

Hold for reverse side of Figure 3.2-1 (11x17)

The feedwater train consists of seven closed feedwater heaters (four low pressure and three high pressure), and one open feedwater heater (deaerator). Condensate is defined as fluid pumped from the condenser hotwell to the deaerator inlet. Feedwater is defined as fluid pumped from the deaerator storage tank to the boiler inlet. Extractions for feedwater heating, deaerating, and the boiler feed pump are taken from the HP, IP, and LP turbine cylinders, and from the cold reheat piping.

The net plant output power, after plant auxiliary power requirements are deducted, is nominally 402 MWe. The overall net plant efficiency is 39.9 percent. An estimate of the auxiliary loads is presented in Table 3.2-1

3.2.3 Emissions Performance

This supercritical pulverized coal-fired plant is designed for compliance with national clean air standards expected to be in effect in the first decade of the next century. A summary of the plant emissions is presented in Table 3.2-2.

Table 3.2-2
AIRBORNE EMISSIONS - SUPERCRITICAL PC WITH FGD

	Values at Design Condition (65% and 85% Capacity Factor)			
	lb/10^6 Btu	**Tons/year 65%**	**Tons/year 85%**	**lb/MWh**
SO_2	0.17	1,686	2,205	1.47
NOx	0.157	1,544	2,019	1.35
Particulates	0.01	97	127	0.08
CO_2	203.2	1,991,686	2,604,512	1,740

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the wet limestone FGD system. The nominal overall design basis SO_2 removal rate is set at 96 percent.

The minimization of NOx production and subsequent emission is achieved by a combination of low-NOx burners, overfire air staging, and selective catalytic reduction (SCR). The low-NOx burners utilize zoning and staging of combustion. Overfire air staging is employed in the design of this boiler. SCR utilizes the injection of ammonia and a catalyst to reduce the NOx emissions.

Particulate discharge to the atmosphere is reduced by the use of a modern fabric filter, which provides a particulate removal rate of 99.9 percent.

CO_2 emissions are equal to those of other coal-burning facilities on an intensive basis (lb/MMBtu), since a similar fuel is used (Illinois No. 6 coal). However, total CO_2 emissions are lower than for a typical PC plant with this capacity due to the relatively high thermal efficiency.

3.2.4 Steam Generators and Ancillaries

The steam generator in this reference supercritical PC-fired plant is a once-through, wall-fired, balanced draft type unit. It is assumed for the purposes of this study that the power plant is designed to be operated as a base-loaded unit for the majority of its life, with some weekly cycling the last few years. The following brief description is for reference purposes.

3.2.4.1 Scope and General Arrangement

The steam generator comprises the following:

- Once-through type boiler
- Water-cooled furnace, dry bottom
- Two-stage superheater
- Reheater
- Startup circuit, including integral separators
- Fin-tube economizer
- Coal feeders and bowl mills (pulverizers)
- Coal and oil burners

- Air preheaters (Ljungstrom type)
- Spray type desuperheater
- Soot-blower system
- Forced draft (FD) fans
- Primary air (PA) fans

The steam generator operates as follows:

Feedwater and Steam

The feedwater enters the economizer, recovers heat from the combustion gases exiting the steam generator, and then passes to the water wall circuits enclosing the furnace. After passing through the lower and then the upper furnace circuits in sequence, the fluid passes through the convection enclosure circuits to the primary superheater and then to the secondary superheater. The fluid is mixed in cross-tie headers at various locations throughout this path.

The steam then exits the steam generator enroute to the HP turbine. Returning cold reheat steam passes through the reheater and then returns to the IP turbine.

Air and Combusting Products

Air from the FD fans is heated in the Ljungstrum type air preheaters, recovering heat energy from the exhaust gases on their way to the stack. This air is distributed to the burner windbox as secondary air. A portion of the combustion air is supplied by the PA fans. This air is heated in the Ljungstrum type air preheaters and is used as combustion air to the pulverizers. A portion of the air from the PA fans is routed around the air preheaters and is used as tempering air for the pulverizers. Preheated air and tempering air are mixed at each pulverizer to obtain the desired pulverizer fuel-air mixture outlet temperature.

The pulverized coal and air mixture flows to the coal nozzles at the various elevations of the wall-fired furnace. The hot combustion products rise to the top of the boiler and pass horizontally through the secondary superheater and reheater in succession. The gases then turn downward, passing in sequence through the primary superheater, economizer, and air preheater. The gases exit the steam generator at this point and flow to the fabric filter, ID fan, FGD system, and stack.

Fuel Feed

The crushed coal is fed through pairs (six in parallel) of weight feeders and mills (pulverizers). The pulverized coal exits each mill via the coal piping and is distributed to the coal nozzles in the furnace walls.

Ash Removal

The furnace bottom comprises several hoppers, with a clinker grinder under each hopper. The hoppers are of welded steel construction, lined with 9-inch-thick refractory. The hopper design incorporates a water-filled seal trough around the upper periphery for cooling and sealing.

Water and ash discharged from the hopper pass through the clinker grinder to an ash sluice system for conveyance to the ash pond. The description of the balance of the bottom ash handling system is presented in Section 3.2.9. The steam generator incorporates fly ash hoppers under the economizer outlet and air heater outlet. The fly ash handling system is also presented in Section 3.2.9.

Burners

A boiler of this capacity will employ approximately 30 coal nozzles arranged in three elevations, divided between the front and rear walls of the furnace. Each burner is designed as a low-NOx configuration, with staging of the coal combustion to minimize NOx formation. In addition, at least one elevation of overfire air nozzles is provided to introduce additional air to cool the rising combustion products to inhibit NOx formation.

Oil-fired pilot torches are provided for each coal burner for ignition and flame stabilization at startup and low loads.

Air Preheaters

Each steam generator is furnished with two vertical inverted Ljungstrom regenerative type air preheaters. These units are driven by electric motors through gear reducers.

Soot Blowers

The soot-blowing system utilizes an array of retractable nozzles and lances that travel forward to the blowing position, rotate through one revolution while blowing, and are then withdrawn. Electric motors drive the soot blowers through their cycles. The soot-blowing medium is steam.

3.2.5 Turbine Generator and Auxiliaries

The turbine consists of an HP section, IP section, and two double-flow LP sections, all connected to the generator by a common shaft. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 3500 psig/1050°F. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the boiler for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 557 psig/1050°F. After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the two LP sections. The steam divides into four paths and flows through the LP sections exhausting downward into the condenser.

Turbine bearings are lubricated by a closed-loop, water-cooled pressurized oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip the oil is pumped by an emergency oil pump mounted on the reservoir. When the turbine reaches 95 percent of synchronous speed, oil is pumped by the main pump mounted on the turbine shaft. The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a labyrinth gland arrangement connected to a low-pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure regulating valves control the gland leader pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is condensed in the packing exhauster and returned to the condensate system.

The generator stator is cooled with a closed-loop water system consisting of circulating pumps, shell and tube or plate and frame type heat exchangers, filters, and deionizers, all skid-mounted. Water temperature is controlled by regulating heat exchanger bypass water flow. Stator cooling water flow is controlled by regulating stator inlet pressure.

The generator rotor is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Stator cooling water flows through these coils. Gas is prevented from escaping at the rotor shafts using a closed-loop oil seal system. The oil seal system consists of a storage tank, pumps, filters, and pressure controls, all skid-mounted.

Operation Description

The turbine stop valves, control valves, reheat stop valves, and intercept valves are controlled by an electro-hydraulic control system.

The turbine is designed to operate at constant inlet steam pressure over the entire load range and is capable of being converted in the future to sliding pressure operation for economic unit cycling.

3.2.6 Coal Handling System

The function of the coal handling system is to provide the equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the pulverizer fuel inlet. The system is designed to support short-term operation at the 5 percent over pressure/valves wide open (OP/VWO) condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

Operation Description

The 6" x 0 bituminous Illinois No. 6 coal is delivered to the site by unit trains of 100-ton rail cars. Each unit train consists of 100, 100-ton rail cars. The unloading will be done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 6" x 0 coal from the feeder is discharged onto a belt conveyor (No. 1). The coal is then transferred to a conveyor (No. 2) that transfers the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron, and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor (No. 3) that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3" x 0 by the first of two coal crushers. The coal then enters a second crusher that reduces the coal size to 1" x 0. The coal is then transferred by conveyor No. 4 to the transfer tower. In the transfer tower the coal is routed to the tripper, which loads the coal into one of the six silos.

Technical Requirements and Design Basis

- Coal burn rate:
  - Maximum coal burn rate = 295,104 lb/h = 147 tph (based on 100% load); add a design margin of 5% to get a burn rate of 154 tph
  - Average coal burn rate = 250,000 lb/h = 125 tph (based on maximum coal burn rate multiplied by an 85% capacity factor), 131 tph with design margin
- Coal delivered to the plant by unit trains:
  - Two and one-half unit trains per week at maximum burn rate
  - Two unit trains per week at average burn rate
  - Each unit train shall have 10,000 tons (100-ton cars) capacity
  - Unloading rate = 900 tph

  - Total unloading time per unit train = 13 hours
  - Conveying rate to storage piles = 900 tph
  - Reclaim rate = 450 tph

- Storage piles with liners, run-off collection, and treatment systems:
  - Active storage = 12,000 tons (72 hours)
  - Dead storage = 270,000 tons (90 days)

3.2.7 Limestone Handling and Reagent Preparation System

The function of the limestone handling and reagent preparation system is to receive, store, convey, and grind the limestone delivered to the plant. The scope of the system is from the storage pile up to the limestone feed system. The system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent guarantee point (30 days). Truck roadways, turnarounds, and unloading hoppers are included in this reference plant design.

Operation Description

For the purposes of this conceptual design, limestone will be delivered to the plant by 25-ton trucks.

The limestone is unloaded onto a storage pile located above vibrating feeders. The limestone is fed onto belt conveyors via vibrating feeders and then to a day bin equipped with vent filters. The day bin supplies a 100 percent capacity size ball mill via a weigh feeder. The wet ball mill accepts the limestone and grinds the limestone to 90 to 95 percent passing 325 mesh (44 microns). Water is added at the inlet to the ball mill to create a limestone slurry. The reduced limestone slurry is then discharged into the mill slurry tank. Mill recycle pumps, two for the tank, pump the limestone water slurry to an assembly of hydroclones and distribution boxes. The slurry is classified into several streams, based on suspended solids content and size distribution.

The hydroclone underflow is directed back to the mill for further grinding. The hydroclone overflow is routed to a reagent storage tank. Reagent distribution pumps direct slurry from the tank to the absorber module.

<u>Technical Requirements and Design Basis</u>

- Limestone usage rate:
  - Maximum limestone usage rate = 30,060 lb/h = 15 tph plus 10% margin = 16.5 tph (based on operating at MCR; 150 tph firing rate for design coal and 80% $CaCO_3$ in the limestone)
  - Average limestone usage rate = 25,600 lb/h = 12.7 tph (based on maximum limestone usage rate multiplied by 85% capacity factor)
- Limestone delivered to the plant by 25-ton dump trucks
- Total number of trucks per day = 16
- Total unloading time per day = 4 hours
- Total time, interval per truck = 15 minutes/truck
- Receiving hopper capacity = 35 tons
- Limestone received = 1" x 0
- Limestone storage capacity = 12,000 tons (30 days supply at maximum burn rate)
- Storage pile size = 180 ft x 90 ft x 40 ft high
- Day bin storage = 300 tons (16-hour supply at maximum burn rate.)
- Conveying rate to day bin = 115 tph
- Weigh feeder/limestone ball mill capacity = 17 tph (based on 24 hours per day of grinding operations)
- Mill slurry tank capacity = 10,000 gallons

- Mill recycle pump capacity = 600 gpm each of two pumps, two per mill
- No. of hydroclones = One assembly, rated at 600 gpm
- Reagent storage tank capacity = 200,000 gallons, 1 tank
- Reagent distribution pump capacity = 300 gpm, each of two pumps

3.2.8 Emissions Control Systems

3.2.8.1 Flue Gas Desulfurization (FGD) System

The function of the FGD system is to scrub the boiler exhaust gases to remove 96 percent of the SO_2 content prior to release to the environment. The scope of the FGD system is from the outlet of the ID fans to the stack inlet. The system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent design point (30 days).

Operation Description

The flue gas exiting the air preheater section of the boiler passes through a fabric filter, then through the ID fans and into the one 100 percent capacity absorber module. The absorber module is designed to operate with counter-current flow of gas and reagent. Upon entering the bottom of the absorber vessel, the gas stream is subjected to an initial quenching spray of reagent. The gas flows upward through a tray, which provides enhanced contact between gas and reagent. Multiple sprays above the tray maintain a consistent reagent concentration in the tray zone. Continuing upward, the reagent laden gas passes through several levels of moisture separators. These will consist of chevron-shaped vanes that direct the gas flow through several abrupt changes in direction, separating the entrained droplets of liquid by inertial effects. The scrubbed and dried flue gas exits at the top of the absorber vessel and is routed to the plant stack. The FGD system for this plant is designed to continuously remove 96 percent of the SO_2.

Formic acid is used as a buffer to enhance the SO_2 removal characteristics of the FGD system. The system will include truck unloading, storage, and transfer equipment.

The scrubbing slurry falls to the lower portion of the absorber vessel, which contains a large inventory of liquid. Oxidation air is added to promote the oxidation of calcium sulfate, contained in the slurry, to calcium sulfate (gypsum). Multiple agitators operate continuously to prevent settling of solids and enhance mixture of the oxidation air and the slurry. Recirculation pumps recirculate the slurry from the lower portion of the absorber vessel to the spray level. Spare recirculation pumps are provided to ensure availability of the absorber.

The absorber chemical equilibrium is maintained by continuous makeup of fresh reagent, and blowdown of spent reagent via the bleed pumps. A spare bleed pump is provided to ensure availability of the absorber. The spent reagent is routed to the byproduct dewatering system. The circulating slurry is monitored for pH and density.

This FGD system is designed for "wet stack" operation. Scrubber bypass or reheat, which may be utilized at some older facilities to ensure the exhaust gas temperature is above the saturation temperature, is not employed in this reference plant design because new scrubbers have improved mist eliminator efficiency, and detailed flow modeling of the flue interior enables the placement of gutters and drains to intercept moisture that may be present and convey it to a drain. Consequently, raising the exhaust gas temperature is not necessary.

<u>Technical Requirements and Design Basis</u>

- Number and type of absorber modules = One, 100% capacity, counter-current tower design, including quench, absorption and moisture separation zones, recirculated slurry inventory in lower portion of absorber vessel
- Slurry recirculation pumps = Four at 33% capacity each
- Slurry bleed pumps = Two at 100% capacity each
- Absorber tank agitators = Six each with 20 hp motor
- Oxidation air blowers = Two at 100% capacity each
- Formic acid system = One system at 100% capacity

- Stack = One reinforced concrete shell, 70-foot outside diameter at the base, 500 feet high with a fiberglass-reinforced plastic (FRP) chimney liner, 19 feet in diameter

3.2.8.2 Byproduct Dewatering

The function of the byproduct dewatering system is to dewater the bleed slurry from the FGD absorber modules. The dewatering process selected for this plant is a gypsum stacking system. The scope of the system is from the bleed pump discharge connections to the gypsum stack. The system is designed to support operation on a 20-year life cycle.

Operation Description

The recirculating reagent in the FGD absorber vessel accumulates dissolved and suspended solids on a continuous basis, as byproducts from the SO_2 absorption reactions process. Maintenance of the quality of the recirculating reagent requires that a portion be withdrawn and replaced by fresh reagent. This is accomplished on a continuous basis by the bleed pumps pulling off spent reagent and the reagent distribution pumps supplying fresh reagent to the absorber.

Gypsum (calcium sulfate) is produced by the injection of oxygen into the calcium sulfite produced in the absorber tower sump. The gypsum slurry, at approximately 15 percent solids, is pumped to a gypsum stacking area. A starter dike is constructed to form a settling pond so that the 15 percent solid gypsum slurry is pumped to the sedimentation pond, where the gypsum particles settle and the excess water is decanted and recirculated back to the plant through the filtrate system. A gypsum stacking system allows for the possibility of a zero discharge system. The stacking area consists of approximately 42 acres, enough storage for 20 years of operation. The gypsum stack is rectangular in plan shape, and is divided into two sections. This allows one section to drain while the other section is in use. There is a surge pond around the perimeter of the stacking area, which accumulates excess water for recirculation back to the plant. The stacking area includes all necessary geotechnical liners and construction to protect the environment.

3.2.8.3 NOx Control

The plant will be designed to achieve 0.158 lb/MMBtu (1.35 lb/MWh) NOx emissions. Two measures are taken to reduce the NOx. The first is a combination of low-NOx burners and the introduction of staged overfire air in the boiler. The low-NOx burners and overfire air reduce the emissions by 65 percent as compared to a boiler installed without low-NOx burners.

The second measure taken to reduce the NOx emissions is the installation of an SCR system prior to the air heater. SCR uses ammonia and a catalyst to reduce NOx to N_2 and H_2O. The SCR system consists of three subsystems – reactor vessel, ammonia storage and injection, and gas flow control. The SCR system will be designed to remove 63 percent of the incoming NOx. This along with the low-NOx burners will achieve the emission limit of 0.158 lb/MMBtu.

Selective noncatalytic reduction (SNCR) was and could be considered for this application. However, with the installation of the low-NOx burners, the boiler exhaust gas contains relatively small amounts of NOx, which makes removal of the quantity of NOx with SNCR to reach the emissions of 0.157 lb/MMBtu difficult. SNCR works better in applications that contain medium to high quantities of NOx and removal efficiencies in the range of 40 to 60 percent. SCR, because of the catalyst used in the reaction, can achieve higher efficiencies with lower concentrations of NOx.

Operation Description

The reactor vessel is designed to allow proper retention time for the ammonia to contact the NOx in the boiler exhaust gas. Ammonia is injected into the gas immediately prior to entering the reactor vessel. The catalyst contained in the reactor vessel enhances the reaction between the ammonia and the NOx in the gas. Catalysts consist of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. Also included with the reactor vessel is soot-blowing equipment used for cleaning the catalyst.

The ammonia storage and injection system consist of the unloading facilities, bulk storage tank, transfer pumps, dilution air skid, and injection grid.

The flue gas flow control consists of ductwork, dampers, and flow straightening devices required to route the boiler exhaust to the SCR reactor and then to the air heater. The economizer bypass as well as the SCR reactor bypass duct and dampers are also included.

Technical Requirements and Design Basis

- Process parameters:
  - Ammonia slippage — 5 mole %
  - Ammonia type — Aqueous (70% water)
  - Ammonia required — 1,290 lb/h
  - Dilution air — 16,000 lb/h
- Major components:
  - Reactor vessel

Quantity	Two
Type	Vertical flow
Catalyst quantity	Three layers with capacity for fourth
Catalyst type	Plate or honeycomb
Inlet damper	Louver
Outlet damper	Louver

  - Dilution air skid

Quantity	One
Capacity	4,000 scfm
Number of blowers	Two per skid (one operating and one spare)

  - Ammonia transport and storage

Quantity	One

Capacity	1,290 lb/h
Storage tank quantity	One
Storage tank capacity	32,000 gal

3.2.8.4 Particulate Removal

Particulate removal is achieved with the installation of a pulse jet fabric filter. The fabric filter will be designed to remove 99.9 percent of the particulates. This will achieve the emissions of 0.01 lb/MMBtu. The limit of the fabric filter is from the air preheater outlet to the ID fan inlets.

A fabric filter was chosen in anticipation of emission limits of particles less than 2.5 microns in diameter, called $PM_{2.5}$ particles. Although there is still debate, it appears that the fabric filters will be more effective in removing the $PM_{2.5}$ particles, as compared to the installation of an electrostatic precipitator. Also, fabric filters are currently being used successfully on coal-burning plants in the U.S., Europe, and other parts of the world.

<u>Operation Description</u>

The fabric filter chosen for this study is a pulse jet fabric filter. The boiler exhaust gas enters the inlet plenum of the fabric filter and is distributed among the modules. Gas enters each module through a vaned inlet near the bottom of the module above the ash hopper. The gas then turns upward and is uniformly distributed through the modules, depositing the fly ash on the exterior surface of the bags. Clean gas passes through the fabric and into the outlet duct through poppet dampers. From the outlet dampers the gas enters the ID fan.

Periodically each module is isolated from the gas flow, and the fabric is cleaned by a pulse of compressed air injected into each filter bag through a venturi nozzle. This cleaning dislodges the dust cake collected on the filter bag exterior. The dust falls into the ash hopper and is removed through the ash handling system.

<u>Technical Requirements and Design Basis</u>

- Flue gas flow 1,175,000 acfm

- Air-to-cloth ratio 4 acfm/ft^2
- Ash loading 23,600 lb/h
- Pressure drop 6 in. W.C.

3.2.8.5 Hazardous Air Pollutants (HAPs) Removal

The U.S. Environmental Protection Agency (EPA) has issued the "Interim Final Report" on HAPs. The report is based on on the findings of a study which estimated the emissions of HAPs from utilities. The study looked at 15 HAPs: arsenic, beryllium, cadmium, chromium, lead, manganese, mercury, nickel, hydrogen chloride, hydrogen fluoride, acrolein, dioxins, formaldehyde, n-nitrosodimethy-lamine, and radionuclides.

Analysis of the data obtained from coal fired plants shows that emissions from only two of the 426 plants studied pose a cancer risk greater than the study guidelines of 1 in 1 million. It appears that the HAPs emissions from coal fired plants are less than originally thought. Based on the interim report, extensive control of HAPs will not be required. However, due to the number of outstanding issues and the ever changing environment, it is difficult to predict the whether coal-fired utility boilers will be among those regulated with respect to HAPs.

Lower emissions of lead, nickel, chromium, cadmium, and some radionuclides, which are primarily particulate at typical air heater outlets, are achieved by the installation of high-efficiency particulate removal devices such as the fabric filter used in this study.

One HAP that has received a lot of attention over the last several years is mercury. Mercury has been found in fish and other aquatic life, and there is concern about the effects of mercury on the environment. Reducing mercury air emissions is complex, and several systems are being investigated to remove mercury, including:

- Activated carbon injection
- Injection of calcium based sorbents
- Pumice injection

- Injection of compounds prior to an FGD system to convert mercury to oxides of mercury
- Electrically induced oxidation of mercury to produce a mercury oxide that can be removed with particulate controls
- Introduction of a catalyst to promote the oxidation of elemental mercury and subsequent removal in an FGD system

Mercury controls are still being investigated and optimized and will require additional evaluation before optimal removal methods are established.

Mercury existing as oxidized mercury can be easily removed in a wet FGD system. Elemental mercury requires additional treatment for removal to occur. Unfortunately, coals contain various percentages of both elemental and oxidized mercury. The percentage of oxidized mercury in coal can range from 20 to 90 percent. DOE and EPA are still analyzing coals and do not have an extensive list available. Therefore, for this study it will be assumed that the coal will contain 50 percent oxidized mercury.

Since this plant will include a wet FGD system, a catalyst will be used to oxidize the elemental mercury. The catalyst bed will be installed between the fabric filter and the ID fans. The catalysts that show promise to oxidize mercury are iron- and carbon-based catalysts. One of these will be chosen as the catalyst for this application.

3.2.9 Balance of Plant

3.2.9.1 Condensate and Feedwater Systems

Condensate

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser, and the LP feedwater heaters.

Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; four LP heaters; and one deaerator with storage tank.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

Each LP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the condenser. Normal drain levels in the heaters are controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

Feedwater

The function of the feedwater system is to pump feedwater from the deaerator storage tank to the boiler economizer. One turbine-driven boiler feed pump is provided to pump feedwater through the HP feedwater heaters. The pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Each HP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. Feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the deaerator. Normal drain level in the heaters is controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

3.2.9.2 Main, Reheat, and Extraction Steam Systems

Main and Reheat Steam

The function of the main steam system is to convey main steam from the boiler superheater outlet to the high-pressure turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the boiler reheater and from the boiler reheater outlet to the turbine reheat stop valves.

Main steam at approximately 3650 psig/1050°F exits the boiler superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed in a single line feeding the HP turbine. A branch line off the main steam line feeds the two boiler feed pump turbines during unit operation up to 60 percent load.

Cold reheat steam at approximately 620 psig/587°F exits the HP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the boiler reheater. Hot reheat steam at approximately 572 psig/1050°F exits the boiler reheater through a motor-operated gate valve and is routed to the IP turbine. A branch connection from the cold reheat piping supplies steam to feedwater heater 7.

Extraction Steam

The function of the extraction steam system is to convey steam from turbine extraction points through the following routes:

- From HP turbine extraction to heater 8
- From HP turbine exhaust (cold reheat) to heater 7
- From IP turbine extraction to heater 6
- From LP turbine exhaust (cross-over) to the deaerator
- From LP turbine extraction to heaters 1, 2, 3, and 4

The turbine is protected from overspeed on turbine trip, from flash steam reverse flow from the heaters through the extraction piping to the turbine. This protection is provided by positive closing, balanced disk non-return valves located in all extraction lines except the lines to the LP feedwater heaters in the condenser neck. The extraction non-return valves are located only in horizontal runs of piping and as close to the turbine as possible.

The turbine trip signal automatically trips the non-return valves through relay dumps. The remote manual control for each heater level control system is used to release the non-return valves to normal check valve service when required to restart the system.

3.2.9.3 Circulating Water System

The function of the circulating water system is to supply cooling water to condense the main turbine exhaust steam. The system consists of two 50 percent capacity vertical circulating water pumps, a multi-cell mechanical draft evaporative cooling tower, and carbon steel cement-lined interconnecting piping. The condenser is a single-pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of each condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

Each pump has a motor-operated discharge gate valve. A motor-operated cross-over gate valve and reversing valves permit each pump to supply both sides of the condenser when the other pump is shut down. The pump discharge valves are controlled manually, but will automatically close when its respective pump is tripped.

3.2.9.4 Ash Handling System

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing the fly ash and bottom ash produced on a daily basis by the boiler. The scope of the system is from the precipitator hoppers, air heater hopper collectors, and bottom ash hoppers to the ash pond (for bottom ash) and truck filling stations (for fly ash). The system is designed to support short-term operation at the 5 percent OP/VWO condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

Operation Description

The fly ash collected in the fabric filter and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system using low-pressure air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

The bottom ash from the boiler is fed into a clinker grinder. The clinker grinder is provided to break up any clinkers that may form. From the clinker grinders the bottom ash is discharged via a hydro-ejector and ash discharge piping to the ash pond.

Ash from the economizer hoppers and pyrites (rejected from the coal pulverizers) are conveyed by hydraulic means (water) to the economizer/pyrites transfer tank. This material is then sluiced, on a periodic basis, to the ash pond.

Technical Requirements and Design Basis

- Bottom ash and fly ash rates:
  - Bottom ash generation rate, 5,800 lb/h = 3 tph
  - Fly ash generation rate, 23,300 lb/h = 11.7 tph
- Bottom ash:
  - Clinker grinder capacity = 5 tph
  - Conveying rate to ash pond = 5 tph
- Fly ash:
  - Collection rate = 11.7 tph
  - Conveying rate from precipitator and air heaters = 11.7 tph
  - Fly ash silo capacity = 850 tons (72-hour storage)
  - Wet unloader capacity = 30 tph

3.2.9.5 Ducting and Stack

One stack is provided with a single FRP liner. The stack is constructed of reinforced concrete, with an outside diameter at the base of 70 feet. The stack is 480 feet high for adequate particulate dispersion. The stack has one 19.5-foot-diameter FRP stack liner.

3.2.9.6 Waste Treatment

An onsite water treatment facility will treat all runoff, cleaning wastes, blowdown, and backwash to within EPA standards for suspended solids, oil and grease, pH and miscellaneous metals. All waste treatment equipment will be housed in a separate building. The waste treatment system consists of a water collection basin, three raw waste pumps, an acid neutralization system, an oxidation system, flocculation, clarification/thickening, and sludge dewatering. The water collection basin is a synthetic-membrane-lined earthen basin, which collects rainfall runoff, maintenance cleaning wastes and backwash flows.

The raw waste is pumped to the treatment system at a controlled rate by the raw waste pumps. The neutralization system neutralizes the acidic wastewater with hydrated lime in a two-stage system, consisting of a lime storage silo/lime slurry makeup system with 50-ton lime silo, a 0-1000 lb/h dry lime feeder, a 5,000-gallon lime slurry tank, slurry tank mixer, and 25 gpm lime slurry feed pumps.

The oxidation system consists of a 50 scfm air compressor, which injects air through a sparger pipe into the second-stage neutralization tank. The flocculation tank is fiberglass with a variable speed agitator. A polymer dilution and feed system is also provided for flocculation. The clarifier is a plate-type, with the sludge pumped to the dewatering system. The sludge is dewatered in filter presses and disposed off-site. Trucking and disposal costs are included in the cost estimate. The filtrate from the sludge dewatering is returned to the raw waste sump.

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water will be provided. A 200,000-gallon storage tank will provide a supply of No. 2 fuel oil used for startup and for a small auxiliary boiler. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

3.2.10 Accessory Electric Plant

The accessory electric plant consists of all switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, all wire and cable. It also includes the main power transformer, all required foundations, and standby equipment.

3.2.11 Instrumentation and Control

An integrated plant-wide control and monitoring system (DCS) is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor (CRT) and keyboard units. The CRT/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability. The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual with operator selection of modular automation routines available.

3.2.12 Buildings and Structures

A soil bearing load of 5000 lb/ft^2 is used for foundation design. Foundations are provided for the support structures, pumps, tanks, and other plant components. The following buildings are included in the design basis:

- Steam turbine building
- Boiler building
- Administration and service building
- Makeup water and pretreatment building
- Pump house and electrical equipment building
- Fuel oil pump house
- Continuous emissions monitoring building

- Coal crusher building
- River water intake structure
- Guard house
- Runoff water pump house
- Industrial waste treatment building
- FGD system buildings

3.2.13 Equipment List - Major

ACCOUNT 1 COAL AND SORBENT HANDLING

ACCOUNT 1A COAL RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	200 ton	2
2	Feeder	Vibratory	450 tph	2
3	Conveyor No. 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor No. 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	225 tph	2
8	Conveyor No. 3	48" belt	450 tph	1
9	Crusher Tower	N/A	450 tph	1
10	Coal Surge Bin w/ Vent Filter	Compartment	450 ton	1
11	Crusher	Granulator reduction	6"x0 - 3"x0	1
12	Crusher	Impactor reduction	3"x0 - 1"x0	1
13	As-Fired Coal Sampling System	Swing hammer	450 tph	2
14	Conveyor No. 4	48" belt	450 tph	1
15	Transfer Tower	N/A	450 tph	1
16	Tripper	N/A	450 tph	1
17	Coal Silo w/ Vent Filter and Slide Gates	N/A	600 ton	6

ACCOUNT 1B LIMESTONE RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Truck Unloading Hopper	N/A	35 ton	2
2	Feeder	Vibrator	115 tph	2
3	Conveyor No. 1	30" belt	115 tph	1
4	Conveyor No. 2	30" belt	115 tph	1
5	Limestone Day Bin	Vertical cylindrical	300 tons	1

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A COAL PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Feeder	Gravimetric	40 tph	6
2	Pulverizer	B&W type MPS-75	40 tph	6

ACCOUNT 2B LIMESTONE PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Bin Activator		17 tph	1
2	Weigh Feeder	Gravimetric	17 tph	1
3	Limestone Ball Mill	Rotary	17 tph	1
4	Mill Slurry Tank with Agitator		10,000 gal	1
5	Mill Recycle Pumps	Horizontal centrifugal	600 gpm	2
6	Hydroclones	Radial assembly		1
7	Distribution Box	Three-way		1
8	Reagent Storage Tank with Agitator	Field erected	200,000 gal	1
9	Reagent Distribution Pumps	Horizontal centrifugal	300 gpm	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Field fab.	200,000 gal.	1
2	Surface Condenser	Two shell, transverse tubes	1.97×10^6 lb/h 1.4/2.0 in. Hg	1
3	Cond. Vacuum Pumps	Rotary water sealed	2,500/25 scfm	2
4	Condensate Pumps	Vert. canned	2,500 gpm/800 ft	2
5	LP Feedwater Heater 1A/1B	Horiz. U tube	987,600 lb/h 98.2°F to 144.5°F	2
6	LP Feedwater Heater 2A/2B	Horiz. U tube	987,600 lb/h 144.5°F to 174.3°F	2
7	LP Feedwater Heater 3	Horiz. U tube	1,975,200 lb/h 179.3°F to 202.4°F	1
8	LP Feedwater Heater 4	Horiz. U tube	1,975,200 lb/h 202.4°F to 257.2°F	1
9	Deaerator and Storage Tank	Horiz. spray type	1,975,200 lb/h 257.2°F to 294.3°F	1
10	Boiler Feed Pumps/ Turbines	Barrel type, multi-staged, centr.	6,000 gpm @ 9,900 ft	
11	Startup Boiler Feed Pump	Barrel type, multi-staged centr.	1,500 gpm @ 9,900 ft	1
12	HP Feedwater Heater 6	Horiz. U tube	2,700,000 lb/h 331.7°F to 409.8°F	1
13	HP Feedwater Heater 7	Horiz. U tube	2,700,000 lb/h 409.89°F to 486.8°F	1
14	HP Feedwater Heater 8	Horiz. U. tube	2,700,000 lb/h 486.8°F to 544.0°F	1

ACCOUNT 3B MISCELLANEOUS SYSTEMS

Equipment No.	Description	Type	Design Condition	Qty.
1	Auxiliary Boiler	Shop fab. water tube	400 psig, 650°F	1
2	Fuel Oil Storage Tank	Vertical, cylindrical	300,000 gal	1
3	Fuel Oil Unloading Pump	Gear	150 ft, 800 gpm	1
4	Fuel Oil Supply Pump	Gear	400 ft, 80 gpm	2
5	Service Air Compressors	SS, double acting	100 psig, 800 scfm	3
6	Inst. Air Dryers	Duplex, regenerative	400 scfm	1
7	Service Water Pumps	SS, double suction	100 ft, 6,000 gpm	2
8	Closed Cycle Cooling Heat Exch.	Shell & tube	50% cap. each	2
9	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	185 ft, 600 gpm	2
11	Fire Service Booster Pump	Two-stage cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
13	Riverwater Makeup Pumps	SS, single suction	100 ft, 5,750 gpm	2
14	Filtered Water Pumps	SS, single suction	200 ft, 200 gpm	2
15	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
16	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
17	Liquid Waste Treatment System	-	10 years, 25-hour storm	1
18	Condensate Demineralizer	Mixed bed	1,600 gpm	1

ACCOUNT 4 PFBC BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Qty.
1	Once-Through Steam Generator with Air Heater	Universal pressure, wall-fired	2,700,000 pph steam at 3650 psig/ 1050°F	1
2	Primary Air Fan	Axial	379,350 pph, 84,400 acfm, 39" WG, 600 hp	2
3	FD Fan	Cent.	1,235,000 pph, 275,000 acfm, 11" WG, 600 hp	2
4	ID Fan	Cent.	1,808,000 pph, 574,000 acfm, 49" WG 4,800 hp	2

ACCOUNT 5 FLUE GAS CLEANUP

ACCOUNT 5A PARTICULATE CONTROL

Equipment No.	Description	Type	Design Condition	Qty.
1	Fabric Filter	Pulse jet	3,615,200 lb/h, 290°F	1

ACCOUNT 5B FLUE GAS DESULFURIZATION

Equipment No.	Description	Type	Design Condition	Qty.
1	Absorber Module	Spray/tray	1,106,000 acfm	1
2	Recirculation Pump	Horizontal centrifugal	31,500 gpm	4
3	Bleed Pump	Horizontal centrifugal	650 gpm	2
4	Oxidation Air Blower	Centrifugal	5,600 scfm	2
5	Agitators	Side entering	25 hp motor	6
6	Formic Acid Storage Tank	Vertical, diked	1,000 gal	1
7	Formic Acid Pumps	Metering	0.1 gpm	2

Byproduct Dewatering

Equipment No.	Description	Type	Design Condition	Qty.
6	Gypsum Stacking Pump	Horizontal centrifugal	750 gpm	2
7	Gypsum Stacking Area		42 acres	1
8	Process Water Return Pumps	Vertical centrifugal	500 gpm	2
9	Process Water Return Storage Tank	Vertical, lined	200,000 gal	1
10	Process Water Recirculation Pumps	Horizontal centrifugal	500 gpm	2

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Not Applicable

ACCOUNT 7 WASTE HEAT BOILER, DUCTING AND STACK

Equipment No.	Description	Type	Design Condition	Qty.
1	Stack	Reinf. concrete, two FRP flues	60 ft/sec exit velocity 480 ft high x 19 ft dia. (flue)	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty.
1	435 MW Turbine Generator	TC4F30	3500 psig, 1050°F/1050°F	1
2	Bearing Lube Oil Coolers	Shell & tube	-	2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop	-	1
4	Control System	Electro-hydraulic	1600 psig	1
5	Generator Coolers	Shell & tube	-	2
6	Hydrogen Seal Oil System	Closed loop	-	1
7	Generator Exciter	Solid state brushless	-	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Cooling Tower	Mech draft	160,000 gpm 95°F to 75°F	1
2	Circ. W. Pumps	Vert. wet pit	80,000 gpm @ 80 ft	2

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

ACCOUNT 10A BOTTOM ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Economizer Hopper (part of Boiler scope of supply)			4
2	Bottom Ash Hopper (part of Boiler scope of supply)			2
3	Clinker Grinder		10 tph	2
4	Pyrites Hopper (part of Pulverizer scope of supply included with Boiler)			6
5	Hydroejectors			13
6	Economizer/Pyrites Transfer Tank		40,000 gal	1
7	Ash Sluice Pumps	Vertical, wet pit	1,000 gpm	2
8	Ash Seal Water Pumps	Vertical, wet pit	1,000 gpm	2

ACCOUNT 10B FLY ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Fabric Filter Hoppers (part of FF scope of supply)			24
2	Air Heater Hopper (part of Boiler scope of supply)			10
3	Air Blower		1,800 cfm	2
4	Fly Ash Silo	Reinf. concrete	890 tons	1
5	Slide Gate Valves			2
6	Wet Unloader		30 tph	1
7	Telescoping Unloading Chute			1

3.2.14 Conceptual Capital Cost Estimate Summary

The summary of the conceptual capital cost estimate for the 400 MW supercritical PC plant is shown in Table 3.2-3. The estimate summarizes the detail estimate values that were developed consistent with Section 9, "Capital and Production Cost and Economic Analysis." The detail estimate results are contained in Appendix E.

Examination of the values in the table reveal several relationships that are subsequently addressed. The relationship of the equipment cost to the direct labor cost varies for each account. This variation is due to many factors including the level of fabrication performed prior to delivery to the site, the amount of bulk materials represented in the equipment or material cost column, and the cost basis for the specific equipment (degree of field fabrication required for items too large to ship to the site in one or several major pieces). Also note that the total plant cost ($/kW) values are all determined on the basis of the total plant net output. This will be more evident as other technologies are compared. One significant change compared to the other plants is that, unlike all of the other technologies, all of the power is generated from a single source, the steam turbine. As a result, the economy of scale influence is greatest for this plant.

Table 3.2-3

Client: DEPARTMENT OF ENERGY

Project: Market Based Advanced Coal Power Systems

Report Date: 14-Aug-98 08:20 AM

TOTAL PLANT COST SUMMARY

Case: Supercritical PC

Plant Size: 401.8 MW,net

Estimate Type: Conceptual

Cost Base (Jan) 1998 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	6,782	2,004	5,174	362		**$14,321**	1,146		3,093	**$18,560**	46
2	COAL & SORBENT PREP & FEED	8,458		2,633	184		**$11,275**	902		2,435	**$14,613**	36
3	FEEDWATER & MISC. BOP SYSTEMS	16,550		7,175	502		**$24,227**	1,938		6,139	**$32,304**	80
4	PC BOILER & ACCESSORIES											
4.1	PC Boiler	60,723		23,331	1,633		**$85,688**	6,855		9,254	**$101,797**	253
4.2	Open											
4.3	Open											
4.4-4.9	Boiler BoP (w/FD & ID Fans)	3,163		1,042	73		**$4,278**	342		462	**$5,082**	13
	SUBTOTAL 4	*63,886*		*24,373*	*1,706*		***$89,966***	*7,197*		*9,716*	***$106,879***	*266*
5	FLUE GAS CLEANUP	33,591		18,834	1,168		**$53,593**	4,287		5,433	**$63,314**	158
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A		N/A								
6.2-6.9	Combustion Turbine Accessories											
	SUBTOTAL 6											
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A		N/A								
7.2-7.9	HRSG Accessories, Ductwork and Stack	9,491	280	7,038	493		**$17,302**	1,384		2,897	**$21,583**	54
	SUBTOTAL 7	*9,491*	*280*	*7,038*	*493*		***$17,302***	*1,384*		*2,897*	***$21,583***	*54*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	33,394		5,502	385		**$39,281**	3,143		4,242	**$46,666**	116
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	11,839	361	6,493	455		**$19,147**	1,532		3,561	**$24,240**	60
	SUBTOTAL 8	*45,234*	*361*	*11,995*	*840*		***$58,429***	*4,674*		*7,803*	***$70,906***	*176*
9	COOLING WATER SYSTEM	7,685	3,998	7,266	509		**$19,457**	1,557		3,748	**$24,761**	62
10	ASH/SPENT SORBENT HANDLING SYS	5,859	77	10,715	750		**$17,402**	1,392		2,849	**$21,643**	54
11	ACCESSORY ELECTRIC PLANT	9,175	2,859	7,797	546		**$20,376**	1,630		3,608	**$25,614**	64
12	INSTRUMENTATION & CONTROL	6,114		5,069	355		**$11,538**	923		1,941	**$14,401**	36
13	IMPROVEMENTS TO SITE	1,882	1,082	3,768	264		**$6,995**	560		2,266	**$9,821**	24
14	BUILDINGS & STRUCTURES		15,275	18,323	1,283		**$34,881**	2,790		9,418	**$47,090**	117
	TOTAL COST	**$214,705**	**$25,935**	**$130,160**	**$8,961**		**$379,761**	**$30,381**		**$61,347**	**$471,489**	**1173**

Section 3.3

Pulverized Coal-Fired Ultra-Supercritical Plant
400 MWe

3.3 PULVERIZED COAL-FIRED ULTRA-SUPERCRITICAL PLANT - 400 MWe

3.3.1 Introduction

This 400 MWe single unit (nominal) ultra-supercritical pulverized coal-fired electric generating station serves as a market-based reference design for comparison with a series of Clean Coal Technology greenfield power generating stations. The principal design parameters characterizing this plant were established to be representative of a state-of-the-art facility, balancing economic and technical factors.

3.3.2 Heat and Mass Balance

Overall performance for the entire plant is summarized in Table 3.3-1, which includes auxiliary power requirements. The heat and mass balance is based on the use of Illinois No. 6 coal as fuel. The steam power cycle is shown schematically in the 100 percent load Heat and Mass Balance diagram (Figure 3.3-1). The performance presented in this heat balance reflects current state-of-the-art turbine adiabatic efficiency levels, boiler performance, and wet limestone FGD system capabilities. The diagram shows state points at each of the major components for this conceptual design.

The steam cycle used for this case is based on a 4500 psig/1100°F/1100°F/1100°F double reheat configuration. The very-high-pressure (VHP) turbine uses 2,554,000 lb/h steam at 4515 psia and 1100°F. The first cold reheat flow is 2,075,000 lb/h of steam at 1357 psia and 753°F, which is reheated to 1100°F before entering the HP turbine section. The second cold reheat flow is 1,737,178 lb/h of steam at 378 psia and 757°F, which is reheated to 1100°F before entering the IP turbine.

The turbine generator is a single machine comprised of tandem VHP, HP, IP, and LP turbines driving one 3600 rpm hydrogen-cooled generator. The turbine exhausts to a single-pressure condenser operating at 2.0 inches Hga, at the nominal 100 percent load design point.

Table 3.3-1
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, psig	4,500
Throttle Temperature, °F	1,100
First Reheat Outlet Temperature, °F	1,100
Second Reheat Outlet Temperature, °F	1,100
POWER SUMMARY (Gross Power at Generator Terminals, kWe)	425,000
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	180
Limestone Handling & Reagent Preparation	790
Pulverizers	1,540
Condensate Pumps	780
Main Feed Pump (Note 1)	14,000
Booster Feed Pump	2,600
Miscellaneous Balance of Plant (Note 2)	2,050
Primary Air Fans	900
Forced Draft Fan	900
Induced Draft Fan	5,489
Baghouse	100
SNCR	80
FGD Pumps and Agitators	2,800
Steam Turbine Auxiliaries	650
Circulating Water Pumps	2,400
Cooling Tower Fans	1,650
Ash Handling	1,410
Transformer Loss	1,020
TOTAL AUXILIARIES, kWe	25,339
Net Power, kWe	399,661
Net Efficiency, % HHV	41.4
Net Heat Rate, Btu/kWh (HHV)	8,251
CONDENSER COOLING DUTY, 10^6 Btu/h	1,475
CONSUMABLES	
As-Received Coal Feed, lb/h	282,675
Sorbent (Limestone) Feed, lb/h	28,790
Ammonia Feed, lb/h	204

Note 1 - Driven by auxiliary steam turbine; electric equivalent not included in total.
Note 2 - Includes plant control systems, lighting, HVAC, etc.

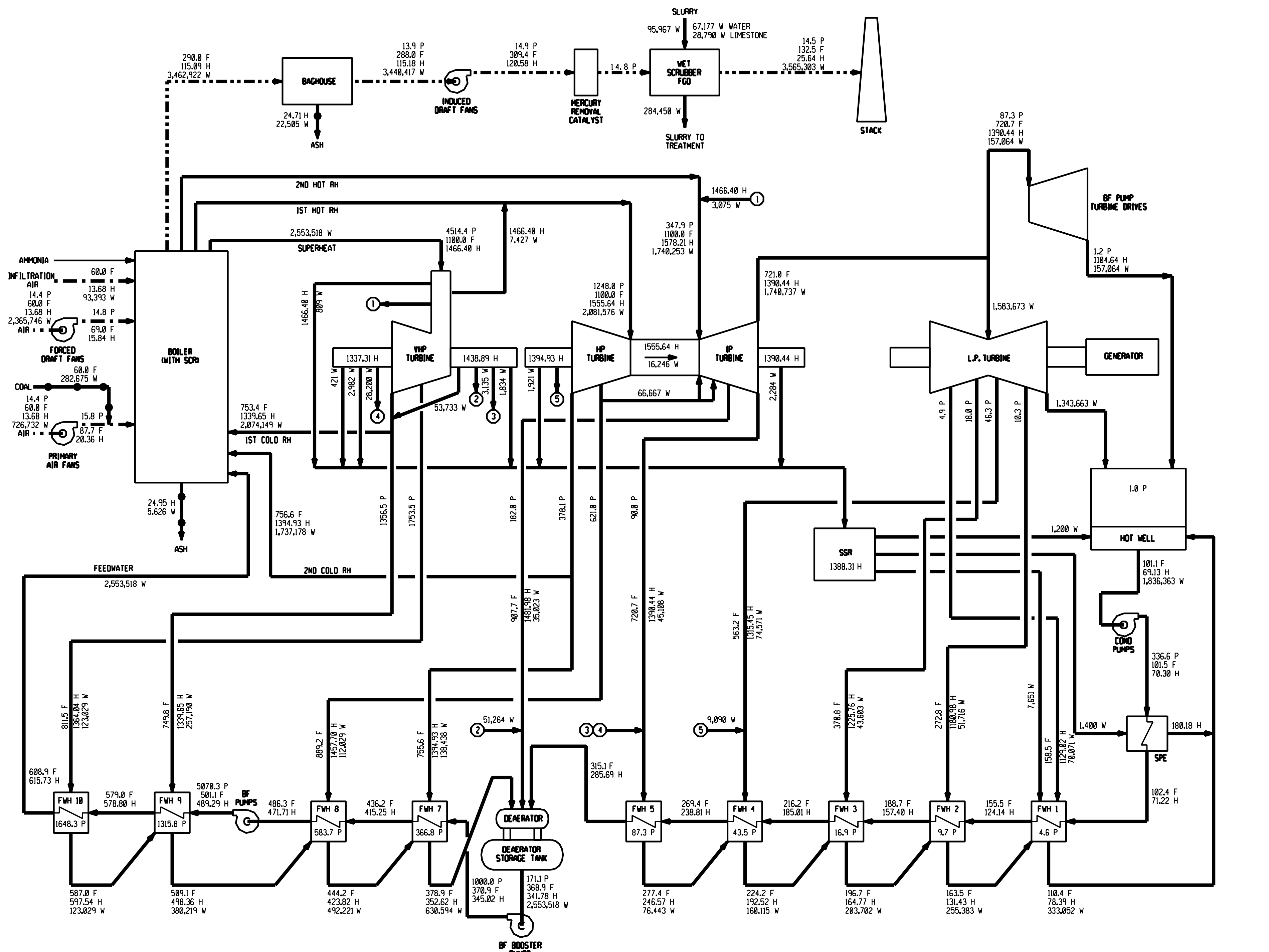

FIGURE 3.3-1

NOTES:

1. STEAM TURBINE PERFORMANCE BASED ON TC2F40 GE MACHINE.
2. STEAM CYCLE IS 4500/1100/1100/1100/2 IN HGA.
3. BF BOOSTER PUMPS ARE MOTOR DRIVEN.

LEGEND

(solid line)	CONDENSATE, FEEDWATER, OR STEAM
(line with dots)	COAL OR ASH
(dash-dot line)	AIR
(dash-dot-dot line)	FLUE GAS
P	PRESSURE, PSIA
F	TEMPERATURE, °F
H	ENTHALPY, BTU/LBM
W	MASS FLOW, LBM/HR
MWe	POWER, MEGAWATTS ELECTRICAL

SYSTEM PERFORMANCE SUMMARY

GROSS POWER :	432.4 MWe
GENERATOR LOSS :	7.4 MWe
AUXILIARY POWER :	25.3 MWe
NET PLANT POWER :	399.7 MWe
NET PLANT EFFICIENCY :	41.4 %
NET PLANT HEAT RATE :	8251 Btu/kwh

REV | DATE | DESCRIPTION | DRAWN | CHECKED | LEAD DESIGNER | LEAD DISCIPLINE ENGINEER | PROJ. ENGR. MANAGER | PROJECT MANAGER

STATUS OF DRAWING: PRELIMINARY — DEFINITION: REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.

CONSTRUCTION STATUS

DRAWN BY: CLB — DATE

CHECKED BY — DATE

LEAD DESIGNER — DATE

ENGINEER — DATE

LEAD DISCIPLINE ENGR. — DATE

ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF PE: STATE: LIC. NO.: DATE:

PROJECT ENGINEERING MANAGER

PROJECT MANAGER

PARSONS
PARSONS POWER GROUP INC.
READING / BOSTON / CHARLOTTE / CHATTANOOGA

CLIENT/PROJECT TITLE
CLEAN COAL TECHNOLOGH PROGRAM
PULVERIZED COAL ULTRACRITICAL REF. PLANT
DEPARTMENT OF ENERGY TASK 22

PLANT HEAT AND MATERIAL BALANCE
100% RATED POWER

SCALE: NONE

PARSON'S DWG. NO.: MBAC-1-400-314-003 — REV: A

PPGI-FILE: PC-UC03A / PCUC03AT
PPGI-DATE: 7/10.15/1997 11:02 7:37
P.M.WITMAN / J.S.WHITE

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The feedwater train consists of nine closed feedwater heaters (five low-pressure and four high-pressure), and one open feedwater heater (deaerator). Condensate is defined as fluid pumped from the condenser hotwell to the deaerator inlet. Feedwater is defined as fluid pumped from the deaerator storage tank to the boiler inlet. Extractions for feedwater heating, deaerating, and the boiler feed pump are taken from the HP, IP, and LP turbine cylinders, and from the cold reheat piping.

The net plant output power, after plant auxiliary power requirements are deducted, is 400 MWe. The overall net plant efficiency is 41.4 percent. An estimate of the auxiliary loads is presented in Table 3.3-1.

3.3.3 Emissions Performance

This ultra-supercritical pulverized coal-fired plant is designed for compliance with national clean air standards expected to be in effect in the year 2010. More stringent requirements that are applicable to non-attainment areas are not applied herein. A summary of the plant's emissions is presented in Table 3.3-2.

Table 3.3-2
AIRBORNE EMISSIONS - ULTRA-SUPERCRITICAL PC WITH FGD

	Values at Design Condition (65% and 85% Capacity Factor)			
	1b/10^6 Btu	Tons/year 65%	Tons/year 85%	lb/MWh
SO_2	0.17	1,615	2,112	1.42
NOx	0.16	1,526	1,996	1.35
Particulates	0.01	93	122	0.08
CO_2	203.2	1,907,827	2,494,851	1,679

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the wet limestone FGD system. The nominal overall design basis SO_2 removal rate is set at 96 percent.

The minimization of NOx production and subsequent emission are achieved by the zoning and staging of combustion in the low low-NOx burners and the overfire air staging employed in the design of this boiler. The technique of selective non-catalytic reduction (SNCR) will reduce NOx emissions further, and is applied to the subject plant in accordance with the projection of environmental restrictions required by the year 2010.

Particulate discharge to the atmosphere is reduced by the use of a pulse jet fabric filter, which provides a particulate removal rate of 99.9 percent.

CO_2 emissions are equal to those of other coal-burning facilities on an intensive basis (1b/MMBtu), since a similar fuel is used (Illinois No. 6 coal). However, total CO_2 emissions are lower than for a typical PC plant with this capacity due to the relatively high thermal efficiency.

3.3.4 Steam Generators and Ancillaries

The steam generator in this reference market-based ultra-supercritical PC-fired plant is a once-through, wall-fired, balanced draft type unit. It is assumed for the purposes of this study that the power plant is designed to be operated as a base-loaded unit for the majority of its life, with some weekly cycling the last few years. The following brief description is for reference purposes.

3.3.4.1 Scope and General Arrangement

The steam generator is comprised of the following:

- Once-through type boiler
- Water-cooled furnace, dry bottom
- Two-stage superheater
- Reheaters (two stages)
- Startup circuit, including integral separators
- Fin-tube economizer
- Coal feeders and bowl mills (pulverizers)

- Coal and oil burners
- Air preheaters (Ljungstrom type)
- Spray type desuperheater
- Soot-blower system
- FD fans
- PA fans

The steam generator operates as follows:

Feedwater and Steam

The feedwater enters the economizer, recovers heat from the combustion gases exiting the steam generator, and then passes to the water wall circuits enclosing the furnace. After passing through the lower and then the upper furnace circuits in sequence, the fluid passes through the convection enclosure circuits to the primary superheater and then to the secondary superheater. The fluid is mixed in cross-tie headers at various locations throughout this path.

The steam then exits the steam generator enroute to the VHP turbine. Steam from the VHP turbine returns to the steam generator as first cold reheat and returns to the HP turbine as first hot reheat. Steam from the HP turbine returns to the steam generator as second cold reheat and returns to the IP turbine as second hot reheat.

Air and Combusting Products

Air from the FD fans is heated in the Ljungstrom type air preheaters, recovering heat energy from the exhaust gases on their way to the stack. This air is distributed to the burner windbox as secondary air. A portion of the combustion air is supplied by the PA fans. This air is heated in the Ljungstrom type air preheaters and is used as combustion air to the pulverizers. A portion of the air from the PA fans is routed around the air preheaters and is used as tempering air for the pulverizers. Preheated air and tempering air are mixed at each pulverizer to obtain the desired pulverizer fuel-air mixture outlet temperature.

The pulverized coal and air mixture flows to the coal nozzles at the various elevations of the wall-fired furnace. The hot combustion products rise to the top of the boiler and pass horizontally through the secondary superheater and reheater in succession. The gases then turn downward, passing in sequence through the primary superheater, economizer, and air preheater. The gases exit the steam generator at this point and flow to the precipitator, ID fan, FGD system, and stack.

Fuel Feed

The crushed coal is fed through pairs (three in parallel) of weight feeders and mills (pulverizers). The pulverized coal exits each mill via the coal piping and is distributed to the coal nozzles in the furnace walls.

Ash Removal

The furnace bottom is comprised of several hoppers, with a clinker grinder under each hopper. The hoppers are of welded steel construction, lined with 9-inch-thick refractory. The hopper design incorporates a water-filled seal trough around the upper periphery for cooling and sealing.

Water and ash discharged from the hopper pass through the clinker grinder to an ash sluice system for conveyance to the ash pond. The description of the balance of the bottom ash handling system is presented in Section 3.3.9. The steam generator incorporates fly ash hoppers under the economizer outlet and air heater outlet.

Burners

A boiler of this capacity will employ approximately 30 coal nozzles arranged in three elevations, divided between the front and rear walls of the furnace.

It is anticipated for this study that low-low-NOx burners will have been developed to reduce the NOx emissions exiting the boiler to 0.2 lb/MMBtu. The Low Emissions Boiler Systems (LEBS) program of DOE is currently involved in developing such burners. The burners operate on the principle of controlled separation of fuel and oxidant. Air is diverted away from the core of the flame, reducing local stoichometry during coal devolatization, and reducing initial NOx formation. The "internal staging" or delayed mixing of some of the combustion air with the fuel allows the released nitrogen volatiles to combine to form molecular nitrogen instead of NOx. In the reducing atmosphere produced by this internal staging, molecules of NOx that do form can be more readily reduced back to molecular nitrogen. In addition, at least one elevation of overfire air nozzles is provided to introduce additional air, which cools the rising combustion products and inhibits NOx formation.

Oil-fired pilot torches are provided for each coal burner for ignition and flame stabilization at startup and low loads.

Air Preheaters

Each steam generator is furnished with two vertical inverted Ljungstrom regenerative type air preheaters. These units are driven by electric motors through gear reducers.

Soot Blowers

The soot-blowing system utilizes an array of retractable nozzles and lances that travel forward to the blowing position, rotate through one revolution while blowing, and are then withdrawn. Electric motors drive the soot blowers through their cycles. The soot-blowing medium is steam.

3.3.5 Steam Turbine Generator and Auxiliaries

The turbine consists of a VHP section, HP section, IP section, and two double-flow LP sections, all connected to the generator by a common shaft. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 4500 psig/1100°F. The steam initially enters the turbine near the middle of the VHP span, flows through the turbine and returns to the boiler for reheating. The first reheat steam flows through the reheat stop valves and intercept valves and enters the HP section at 1248 psig/1100°F. The second cold reheat leaves the HP section and returns to the boiler for reheating. The second reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 347 psig/1100°F. After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP sections exhausting downward into the condenser.

Turbine bearings are lubricated by a closed-loop water-cooled pressured oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip, the oil is pumped by an emergency oil pump mounted on the reservoir. When the turbine reaches 95 percent of synchronous speed, oil is pumped by the main pump mounted on the turbine shaft. The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a labyrinth gland arrangement connected to a low-pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure regulating valves control the gland leader pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is condensed in the packing exhauster and returned to the condensate system.

The generator stator is cooled with a closed-loop water system consisting of circulating pumps, shell and tube or plate and frame type heat exchangers, filters and deionizers, all skid-mounted. Water temperature is controlled by regulating heat exchanger bypass water flow. Stator cooling water flow is controlled by regulating stator inlet pressure.

The generator rotor is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Stator cooling water flows through these coils. Gas is prevented from escaping at the rotor shafts using a closed-loop oil seal system. The oil seal system consists of a storage tank, pumps, filters, and pressure controls, all skid-mounted.

<u>Operation Description</u>

The turbine stop valves, control valves, reheat stop valves, and intercept valves are controlled by an electro-hydraulic control system.

The turbine is designed to operate at constant inlet steam pressure over the entire load range and is capable of being converted in the future to sliding pressure operation for economic unit cycling.

3.3.6 Coal Handling System

The function of the coal handling system is to provide the equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the bottom trestle dumper and coal receiving hoppers up to the pulverizer fuel inlet.

Operation Description

The bituminous coal is delivered to the site by unit trains of 100-ton rail cars. Each unit train consists of 100, 100-ton rail cars. The unloading will be done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 6" x 0 coal from the feeder is discharged onto a belt conveyor (No. 1). The coal is then transferred to a conveyor (No. 2) that transfers the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron, and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor (No. 3) that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3" x 0 in the first of two crushers. The coal then enters the second crusher that reduces the coal size to 1" x 0. The coal is then transferred by conveyor No. 4 to the transfer tower. In the transfer tower the coal is routed to the tripper, which loads the coal into one of the three silos.

Technical Requirements and Design Basis

- Coal burn rate:
  - Maximum coal burn rate = 282,675 lb/h = 142 tph (based on 100% load); add a design margin of 5% to get a burn rate of 150 tph
  - Average coal burn rate = 240,000 lb/h = 120 tph (based on maximum coal burn rate multiplied by an 85% capacity factor)

- Coal delivered to the plant by unit trains
  - Two and one-half unit trains per week at maximum burn rate
  - Two unit trains per week at average burn rate
  - Each unit train shall have 10,000 tons (100-ton cars) capacity
  - Unloading rate = 900 tph
  - Total unloading time per unit train = 13 hours
  - Conveying rate to storage piles = 900 tph
  - Reclaim rate = 430 tph
- Storage piles with liners, run-off collection, and treatment systems
  - Active storage = 11,000 tons (72 hours)
  - Dead storage = 112,000 tons (30 days)

3.3.7 Limestone Handling and Reagent Preparation System

The function of the limestone handling and reagent preparation system is to receive, store, convey, and pulverize the limestone delivered to the plant, and mix it with water to form a slurry for feeding to the FGD system. The scope of the system is from the storage pile up to the FGD absorber module inlet. The system is designed to support short-term operation at the 5 percent over pressure/valves wide open (OP/VWO) condition (16 hours) and long-term operation at the 100 percent guarantee point (30 days or more).

Operation Description

For the purposes of this reference conceptual design, limestone will be delivered to the plant by 25-ton trucks. Rail delivery is an alternative.

The limestone is unloaded onto a storage pile located above vibrating feeders. The limestone is fed onto belt conveyors via vibrating feeders and then to a day bin equipped with vent filters. The day bin supplies a 100 percent capacity size ball mill via a weigh feeder.

The ball mill pulverizes the limestone to 90 to 95 percent passing 325 mesh (44 microns) and discharges the reduced material into a mill slurry tank. Mill recycle pumps, two for the tank, pump the limestone water slurry to an assembly of hydroclones and distribution boxes. The slurry is classified into several streams, based on suspended solids content and size distribution.

The hydroclone underflow is directed to the mill for further grinding. The hydroclone overflow is routed to a reagent storage tank. Reagent distribution pumps direct slurry from the tank to the absorber modules.

<u>Technical Requirements and Design Basis</u>

- Limestone usage rate:
  - Maximum limestone usage rate = 282,790 lb/h = 14.4 tph plus 10% design margin = 15.8 tph (based on operating at 100% load, 142 tph firing rate for design coal and 80% $CaCO_3$ in the limestone)
  - Average limestone usage rate = 24,500 lb/h = 12.3 tph (based on maximum limestone usage rate multiplied by an 85% capacity factor)
- Limestone delivered to the plant by 25-ton dump trucks
- Total number of trucks per day = 14
- Total unloading time per day = 4 hours
- Total time, interval per truck = 15 minutes/truck
- Receiving hopper capacity = 35 tons
- Limestone received = 1" x 0
- Limestone storage capacity = 11,000 tons (30-day supply at maximum burn rate)

- Storage pile size = 180 ft x 90 ft x 40 ft high
- Day bin storage = 250 tons (16-hour supply at maximum burn rate)
- Conveying rate to day bins = 115 tph
- Weigh feeder/limestone ball mill capacity = 16 tph (based on 24-hour operation)
- Mill slurry tank capacity =10,000 gallons
- Mill recycle pump capacity = 600 gpm, each of four pumps, two per mill
- No. of hydroclones = one assembly, rated at 600 gpm
- Reagent storage tank capacity = 200,000 gallons, 1 tank (based on 24-hour storage)
- Reagent distribution pump capacity = 300 gpm, each of two pumps

3.3.8 Emissions Control Systems

3.3.8.1 Flue Gas Desulfurization (FGD) System

The function of the FGD system is to scrub the boiler exhaust gases to remove most of the SO_2 content prior to release to the environment. The scope of the FGD system is from the outlet of the ID fans to the stack inlet. The system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent design point (30 days).

Operation Description

The flue gas exiting the air preheater section of the boiler passes through the fabric filter, then through the ID fans and into one 100 percent capacity absorber module. The module is designed to operate with counter-current flow of gas and reagent. Upon entering the absorber vessel, the gas stream is subjected to an initial quenching spray of reagent. The gas flows upward through a tray, which provides enhanced contact between gas and reagent. Multiple sprays above the tray maintain a consistent reagent concentration in the tray zone. Continuing upward, the reagent-laden gas passes through several levels of moisture separators. These typically consist of chevron-shaped vanes that direct the gas flow through several abrupt changes in direction, separating entrained droplets of liquid by inertial effects. The scrubbed and dried flue gas exits at the top of the absorber vessel and is then routed to the plant stack. The FGD system for this reference plant is designed to continuously remove 96 percent of the SO_2 with a high circulating liquid-to-gas ratio.

Formic acid is used as a buffer to enhance the SO_2 removal characteristics of the FGD system. The system will include truck unloading, storage, and transfer equipment.

The scrubbing slurry falls to the lower portion of the absorber vessel, which contains a large inventory of liquid. Multiple agitators operate continuously to prevent settling of solids. A blower forces air, taken from the atmosphere, through a sparger in the bottom of the vessel. This promotes oxidation of the calcium sulfite to calcium sulfate or gypsum. The gypsum is pumped to an onsite gypsum stacking operation as described in Section 3.3.8.2.

The absorber chemical equilibrium is maintained by continuous makeup of fresh reagent, and blowdown of spent reagent via the bleed pumps. The spent reagent is routed to the byproduct dewatering system, Section 3.3.8.2. The circulating reagent is continuously monitored, with pH and density the principal parameters of interest.

This FGD system is design for “wet stack” operation (i.e., no reheat or scrubber bypass is employed to raise exhaust gas temperature at the stack above saturation). This is acceptable since new scrubbers have improved mist eliminator efficiency, and detailed flow modeling of the flue interior enables the placement of gutters and drains to intercept moisture that may be present and convey it to a drain, thereby reducing the potential for carryover and discharge of droplets.

<u>Technical Requirements and Design Basis</u>

- Number and type of absorber modules = One, 100% capacity, counter-current tower design, including quench, absorption and moisture separation zones, recirculated slurry inventory in lower portion of absorber vessel
- Slurry recirculation pumps = Four at 33% capacity each., 30,000 gpm each
- Slurry bleed pumps = Two at 100% capacity each, 600 gpm each
- Oxidation air blowers = Two at 50% capacity each, 5,000 cfm

- Absorber tank agitator = Six, each with 25 hp motor
- Formic acid system = One system at 100% capacity
- Stack = One reinforced concrete shell, 70-foot outside diameter at the base, 500 feet high with a fiberglass-reinforced plastic (FRP) chimney liner, 19 feet in diameter

3.3.8.2 Byproduct Dewatering

The function of the byproduct dewatering system is to dewater the bleed slurry from the FGD absorber module. The dewatering process selected for this reference plant is a gypsum stacking system. The scope of the system is from the bleed pump discharge connections to the gypsum stack. The system is designed to support full-load operation on a 20-year life cycle.

Operation Description

The recirculating reagent in the FGD absorber vessels accumulates dissolved and suspended solids on a continuous basis, as byproducts from the SO_2 absorption reactions proceed. Maintenance of the recirculating reagent requires that a portion be withdrawn and replaced by fresh reagent. This is accomplished on a continuous basis, except for periodic intervals when the spent reagent density may be below predefined limits.

Gypsum (calcium sulfate) is produced by the injection of oxygen into the calcium sulfite produced in the absorber tower sump. The gypsum slurry, at approximately 15 percent solids, is pumped to a gypsum stacking area. A starter dike is constructed to form a settling pond so that the 15 percent solid gypsum slurry is pumped to the sedimentation pond, where the gypsum particles settle and the excess water is decanted and recirculated back to the plant through the filtrate system. A gypsum stacking system allows for the possibility of a zero discharge system. The stacking area consists of approximately 42 acres, enough storage for 20 years of operation. The gypsum stack is rectangular in plan shape, and is divided into two sections. This allows one section to drain while the other section is in use. There is a surge pond around the perimeter of the stacking area, which accumulates excess water for recirculation back to the plant. The stacking area includes all necessary geotechnical liners and construction to protect the environment.

3.3.8.3 NOx Control

The plant will be designed to achieve 0.163 lb/MMBtu (1.35 lb/MWh) NOx emissions. Two measures are taken to reduce the NOx. The first is a combination of low-low-NO_X burners and the introduction of staged overfire air in the boiler. The low-low-NOx burners and overfire air reduce the emissions by 83 percent as compared to a boiler installed without low-NOx burners. The low-low-NOx burners are described in Section 3.3.4.

The second measure taken to reduce the NOx emissions is the installation of an SNCR system prior to the air heater. SNCR uses ammonia injection to reduce NOx to N_2 and H_2O. The SNCR system consists of ammonia storage and injection. The SCR system will be designed to remove 20 percent of the incoming NOx. This, along with the low-NOx burners, will achieve the emission limit of 0.163 lb/MMBtu.

<u>Technical Requirements and Design Basis</u>

- Process parameters:
  - Ammonia slippage — 5 mole %
  - Ammonia type — Aqueous (70% water)
  - Ammonia required — 203 lb/h
  - Dilution air — 2,810 lb/h
- Major components:
  - Dilution air skid:

Quantity	One
Capacity	600 scfm
Number of blowers	Two per skid (one operating and one spare)

  - Ammonia transport and storage:

Quantity	One
Capacity	203 lb/h

Storage tank quantity	One
Storage tank capacity	6,000 gal

3.3.8.4 Particulate Removal

Particulate removal is achieved with the installation of a fabric filter. The fabric filter will be designed to remove 99.9 percent of the particulates. This will achieve the emissions of 0.01 lb/MMBtu. The limit of the fabric filter is from the air preheater outlet to the ID fan inlets.

A fabric filter was chosen in anticipation of emission limits of particles less than 2.5 microns in diameter, called $PM_{2.5}$ particles. Although there is still debate, it appears that the fabric filters will be more effective in removing the $PM_{2.5}$ particles, as compared to the electrostatic precipitators. Also, fabric filters are currently being used successfully on coal-burning plants in the U.S., Europe, and other parts of the world.

Operation Description

The fabric filter chosen for this study is a pulse jet fabric filter. The boiler exhaust gas enters the inlet plenum of the fabric filter and is distributed among the modules. Gas enters each module through a vaned inlet near the bottom of the module above the ash hopper. The gas then turns upward and is uniformly distributed through the modules, depositing the fly ash on the exterior surface of the bags. Clean gas passes through the fabric and into the outlet duct through poppet dampers. From the outlet dampers the gas enters the ID fan.

Periodically each module is isolated from the gas flow, and the fabric is cleaned by a pulse of compressed air injected into each filter bag through a venturi nozzle. This cleaning dislodges the dust cake collected on the filter bag exterior. The dust falls into the ash hopper and is removed through the ash handling system.

Technical Requirements and Design Basis

- Flue gas flow — 1,095,000 acfm
- Air-to-cloth ratio — 4 $acfm/ft^2$

- Ash loading 22,600 lb/h
- Pressure drop 6 in. W.C.

3.3.8.5 Hazardous Air Pollutants (HAPs) Removal

The U.S. Environmental Protection Agency (EPA) has issued the "Interim Final Report" on HAPs. The report is based on the findings of a study which estimated the emissions of HAPs from utilities. The study looked at 15 HAPs: arsenic, beryllium, cadmium, chromium, lead, manganese, mercury, nickel, hydrogen chloride, hydrogen fluoride, acrolein, dioxins, formaldehyde, n-nitrosodimethy-lamine, and radionuclides.

Analysis of the data obtained from coal-fired plants shows that emissions from only two of the 426 plants studied pose a cancer risk greater than the study guidelines of 1 in 1 million. It appears that the HAPs emissions from coal-fired plants are less than originally thought. Based on the interim report, extensive control of HAPs will not be required. However, due to the number of outstanding issues and the ever-changing environment, it is difficult to predict whether coal-fired utility boilers will be among those regulated with respect to HAPs.

Lower emissions of lead, nickel, chromium, cadmium, and some radionuclides, which are primarily particulate at typical air heater outlets, are achieved by the installation of high-efficiency particulate removal devices such as the fabric filter used in this study.

One HAP that has received a lot of attention over the last several years is mercury. Mercury has been found in fish and other aquatic life, and there is concern about the effects of mercury on the environment. Reducing mercury air emissions is complex, and several systems are being investigated to remove mercury, including:

- Activated carbon injection
- Injection of calcium-based sorbents
- Pumice injection
- Injection of compounds prior to an FGD system to convert mercury to oxides of mercury

- Electrically induced oxidation of mercury to produce a mercury oxide, which can be removed with particulate controls

- Introduction of a catalyst to promote the oxidation of elemental mercury and subsequent removal in an FGD system

Mercury controls are still being investigated and optimized and will require additional evaluation before optimal removal methods are established.

Mercury existing as oxidized mercury can be easily removed in a wet FGD system. Elemental mercury requires additional treatment for removal to occur. Unfortunately, coals contain various percentages of both elemental and oxidized mercury. The percentage of oxidized mercury in coal can range from 20 to 90 percent. DOE and EPA are still analyzing coal and do not have an extensive list available. Therefore, for this study it will be assumed that the coal will contain 50 percent oxidized mercury.

Since this plant will include a wet FGD system, a catalyst will be used to oxidize the elemental mercury. The catalyst bed will be installed between the fabric filter and the ID fans. The catalysts that show promise to oxidize mercury are iron-based and carbon-based catalysts. One of these will be chosen as the catalyst for this application.

3.3.9 <u>Balance of Plant</u>

The following section provides a description of the plant outside the PC boiler system and its auxiliaries.

3.3.9.1 Condensate and Feedwater Systems

<u>Condensate</u>

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser and the LP feedwater heaters.

Each system consists of one main condenser, two 50 percent capacity motor-driven vertical condensate pumps, one gland steam condenser, four LP heaters, and one deaerator with storage tank.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

Each LP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the condenser. Normal drain levels in the heaters are controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

Feedwater

The function of the feedwater system is to pump feedwater from the deaerator storage tank to the boiler economizer. One turbine-driven boiler feed pump sized at 100 percent capacity is provided to pump feedwater through the HP feedwater heaters. The feed pump is preceded by a motor-driven booster pump. Each pump is provided with inlet and outlet isolation valves, outlet check valves and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Each HP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. Feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the deaerator. Normal drain level in the heaters is controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

3.3.9.2 Main, Reheat, and Extraction Steam Systems

Main and Reheat Steam

The function of the main steam system is to convey main steam from the boiler superheater outlet to the VHP turbine stop valves. The function of the reheat system is to convey steam from the VHP turbine exhaust to the boiler reheater and from the boiler reheater outlet to the HP turbine stop valves, and from the HP turbine exhaust to the second stage of reheat at the boiler and back to the IP turbine.

Main steam at approximately 4650 psig/1100°F exits the boiler superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed in a single line feeding the HP turbine. A branch line off the main steam line feeds the two boiler feed pump turbines during unit operation up to approximately 40 percent load.

First cold reheat steam at approximately 1400 psig/754°F exits the VHP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the boiler reheater. First hot reheat steam at approximately 1248 psig/1100°F exits the boiler reheater through a motor-operated gate valve and is routed to the HP turbine. Second cold reheat steam at approximately 500 psig/757°F exits the HP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the boiler second reheater. Second hot reheat steam at approximately 348 psig/1100°F exits the boiler reheater through a motor-operated gate valve and is routed to the IP turbine. A branch connection from the second cold reheat piping supplies steam to feedwater heater 7.

Extraction Steam

The function of the extraction steam system is to convey steam from turbine extraction points through the following routes:

- From VHP turbine extraction to heaters 10 and 9
- From HP turbine extraction to heater 8

- From HP turbine exhaust (cold reheat) to heater 7
- From IP turbine extraction to heater 6 and the deaerator
- From LP turbine extraction to heaters 1, 2, 3, and 4

The turbine is protected from overspeed on turbine trip, from flash steam reverse flow from the heaters through the extraction piping to the turbine. This protection is provided by positive closing, balanced disk non-return valves located in all extraction lines except the lines to the LP feedwater heaters in the condenser neck. The extraction non-return valves are located only in horizontal runs of piping and as close to the turbine as possible.

The turbine trip signal automatically trips the non-return valves through relay dumps. The remote manual control for each heater level control system is used to release the non-return valves to normal check valve service when required to restart the system.

3.3.9.3 Circulating Water System

The function of the circulating water system is to supply cooling water to condense the main turbine exhaust steam. The system consists of two 50 percent capacity vertical circulating water pumps, a multi-cell mechanical draft evaporative cooling tower, and carbon steel cement-lined interconnecting piping. The condenser is a single-pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One half of each condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

Each pump has a motor-operated discharge gate valve. A motor-operated cross-over gate valve and reversing valves permit each pump to supply both sides of the condenser when the other pump is shut down. The pump discharge valves are controlled automatically.

3.3.9.4 Ash Handling System

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing the fly ash and bottom ash produced on a daily basis by the boiler. The scope of the system is from the precipitator hoppers, air heater hopper collectors, and bottom ash hoppers to the ash pond (for bottom ash) and truck filling stations (for fly ash). The system is designed to support short-term operation at the 5 percent OP/VWO condition (16 hours) and long-term operation at the 100 percent guarantee point (30 days or more).

Operation Description

The fly ash collected in the fabric filters and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system using low-pressure air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

The bottom ash from the boiler is fed into a clinker grinder. The clinker grinder is provided to break up any clinkers that may form. From the clinker grinders the bottom ash is discharged via a hydro-ejector and ash discharge piping to the ash pond.

Ash from the economizer hoppers and pyrites (rejected from the coal pulverizers) are conveyed by hydraulic means (water) to the economizer/pyrites transfer tank. This material is then sluiced, on a periodic basis, to the ash pond.

Technical Requirements and Design Basis

- Bottom ash:
  - Bottom ash and fly ash rates:
    Bottom ash generation rate, 5,625 lb/h = 2.8 tph
    Fly ash generation rate, 23,300 lb/h = 11.7 tph
  - Clinker grinder capacity = 5 tph
  - Conveying rate to ash pond = 5 tph
- Fly ash:
  - Collection rate = 11.7 tph
  - Conveying rate from precipitator and air heaters = 11.7 tph
  - Fly ash silo capacity = 850 tons (72-hour storage)

– Wet unloader capacity = 30 tph

3.3.9.5 Ducting and Stack

One stack is provided with a single FRP liner. The stack is constructed of reinforced concrete, with an outside diameter at the base of 70 feet. The stack is 480 feet high for adequate particulate dispersion. The stack has one 19-foot-diameter FRP stack liner.

3.3.9.6 Waste Treatment

An onsite water treatment facility will treat all runoff, cleaning wastes, blowdown, and backwash to within EPA standards for suspended solids, oil and grease, pH and miscellaneous metals. All waste treatment equipment will be housed in a separate building. The waste treatment system consists of a water collection basin, three raw waste pumps, an acid neutralization system, an oxidation system, flocculation, clarification/thickening, and sludge dewatering. The water collection basin is a synthetic-membrane-lined earthen basin, which collects rainfall runoff, maintenance cleaning wastes, and backwash flows.

The raw waste is pumped to the treatment system at a controlled rate by the raw waste pumps. The neutralization system neutralizes the acidic wastewater with hydrated lime in a two-stage system, consisting of a lime storage silo/lime slurry makeup system with 50-ton lime silo, a 0-1000 lb/h dry lime feeder, a 5,000-gallon lime slurry tank, slurry tank mixer, and 25 gpm lime slurry feed pumps.

The oxidation system consists of a 50 scfm air compressor, which injects air through a sparger pipe into the second-stage neutralization tank. The flocculation tank is fiberglass with a variable speed agitator. A polymer dilution and feed system is also provided for flocculation. The clarifier is a plate-type, with the sludge pumped to the dewatering system. The sludge is dewatered in filter presses and disposed off-site. Trucking and disposal costs are included in the cost estimate. The filtrate from the sludge dewatering is returned to the raw waste sump.

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water will be provided. A 200,000-gallon storage tank will provide a supply of No. 2 fuel oil used for startup and for a small auxiliary boiler. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

3.3.10 Accessory Electric Plant

The accessory electric plant consists of all switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, all wire and cable. It also includes the main power transformer, all required foundations, and standby equipment.

3.3.11 Instrumentation and Control

An integrated plant-wide control and monitoring system (DCS) is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor (CRT) and keyboard units. The CRT/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability. The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual with operator selection of modular automation routines available.

3.3.12 Buildings and Structures

Buildings and structures are the same as described in Section 3.2.12 for the supercritical plant.

3.3.13 Equipment List - Major

ACCOUNT 1 COAL AND SORBENT HANDLING

ACCOUNT 1A COAL RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	200 ton	2
2	Feeder	Vibratory	450 tph	2
3	Conveyor No. 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor No. 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	225 tph	2
8	Conveyor No. 3	48" belt	450 tph	1
9	Crusher Tower	N/A	450 tph	1
10	Coal Surge Bin w/ Vent Filter	Compartment	450 ton	1
11	Crusher	Granulator reduction	6"x0 - 3"x0	1
12	Crusher	Impactor reduction	3"x0"-1"x0"	1
13	As-Fired Coal Sampling System	Swing hammer	450 tph	2
14	Conveyor No. 4	48" belt	450 tph	1
15	Transfer Tower	N/A	450 tph	1
16	Tripper	N/A	450 tph	1
17	Coal Silo w/ Vent Filter and Slide Gates	N/A	600 ton	6

ACCOUNT 1B LIMESTONE RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Truck Unloading Hopper	N/A	35 ton	2
2	Feeder	Vibrator	115 tph	2
3	Conveyor No. 1	30" belt	115 tph	1
4	Conveyor No. 2	30" belt	115 tph	1
5	Limestone Day Bin	Vertical cylindrical	250 tons	1

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A COAL PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Feeder	Gravimetric	40 tph	6
2	Pulverizer	B&W type MPS-75	40 tph	6

ACCOUNT 2B LIMESTONE PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Bin Activator		16 tph	1
2	Weigh Feeder	Gravimetric	16 tph	1
3	Limestone Ball Mill	Rotary	16 tph	1
4	Mill Slurry Tank with Agitator		10,000 gal	1
5	Mill Recycle Pumps	Horizontal centrifugal	600 gpm	2
6	Hydroclones	Radial assembly		1
7	Distribution Box	Three-way		1
8	Reagent Storage Tank with Agitator	Field erected	200,000 gal	1
9	Reagent Distribution Pumps	Horizontal centrifugal	300 gpm	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Field fab.	200,000 gal.	1
2	Surface Condenser	Single shell, transverse tubes	1.34×10^6 lb/h 2.0 in. Hg	1
3	Cond. Vacuum Pumps	Rotary water sealed	2500/25 scfm	2
4	Condensate Pumps	Vert. canned	2,000 gpm @ 800 ft	2
5	LP Feedwater Heater 1A/1B	Horiz. U tube	918,200 lb/h 102.4°F to 155.5°F	1
6	LP Feedwater Heater 2	Horiz. U tube	1,836,363 lb/h 155.5°F to 188.7°F	1
7	LP Feedwater Heater 3	Horiz. U tube	1,836,363 lb/h 188.7°F to 216.2°F	1
8	LP Feedwater Heater 4	Horiz. U tube	1,836,363 lb/h 216.2°F to 269.4°F	1
9	LP Feedwater Heater 5	Horiz. U tube	1,836,363 lb/h 269.4°F to 315.1°F	1
10	Deaerator and Storage Tank	Horiz. spray type	1,836,363 lb/h 315.1°F to 368.9°F	
11	Boiler Feed Booster Pump	Barrel type, multi-staged centr.	5,500 gpm @ 2,000 ft	1
12	HP Feedwater Heater 7	Horiz. U tube	2,554,000 lb/h 370.9°F to 436.2°F	1
13	HP Feedwater Heater 8	Horiz. U tube	2,554,000 lb/h 436.2°F to 486.3°F	1
14	Boiler Feed Pumps/Turbines	Barrel type, multi-staged, centr.	5,500 gpm @ 9,600 ft	1
15	Startup Boiler Feed Pump	Barrel type, multi-staged centr.	1,500 gpm @ 9,600 ft	1
16	HP Feedwater Heater 9	Horiz. U tube	2,554,000 lb/h 501.1°F to 579°F	1
17	HP Feedwater Heater 10	Horiz. U tube	2,554,000 lb/h 579°F to 608.9°F	1

ACCOUNT 3B MISCELLANEOUS SYSTEMS

Equipment No.	Description	Type	Design Condition	Qty.
1	Auxiliary Boiler	Shop fab. water tube	400 psig, 650°F	1
2	Fuel Oil Storage Tank	Vertical, cylindrical	300,000 gal	1
3	Fuel Oil Unloading Pump	Gear	150 ft, 800 gpm	1
4	Fuel Oil Supply Pump	Gear	400 ft, 80 gpm	2
5	Service Air Compressors	SS, double acting	100 psig, 800 scfm	3
6	Instrument Air Dryers	Duplex, regenerative	400 scfm	1
7	Service Water Pumps	SS, double suction	100 ft, 6,000 gpm	2
8	Closed Cycle Cooling Heat Exch.	Shell & tube	50% cap. each	2
9	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	185 ft, 600 gpm	2
11	Fire Service Booster Pump	Two-stage cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
13	Riverwater Makeup Pumps	SS, single suction	100 ft, 5,750 gpm	2
14	Filtered Water Pumps	SS, single suction	200 ft, 200 gpm	2
15	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
16	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
17	Liquid Waste Treatment System	-	10 years, 25-hour storm	1
18	Condensate Demineralizer	Mixed bed	1,600 gpm	1

ACCOUNT 4 PFBC BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Qty.
1	Once-Through Steam Generator with Air Heater	Universal pressure, wall-fired, double reheat	2,550,000 pph steam at 4500 psig/1100°F	1
2	Primary Air Fan	Axial	363,400 pph, 80,900 acfm, 39" WG, 580 hp	2
3	FD Fan	Cent.	1,182,873 pph, 263,274 acfm, 11" WG, 580 hp	2
4	ID Fan	Cent.	1,724,000 pph, 570,000 acfm, 32" WG, 3,800 hp	2

ACCOUNT 5 FLUE GAS CLEANUP

ACCOUNT 5A PARTICULATE CONTROL

Equipment No.	Description	Type	Design Condition	Qty.
1	Fabric Filter	Pulse jet	3,463,000 lb/h, 290°F	1

ACCOUNT 5B FLUE GAS DESULFURIZATION

Equipment No.	Description	Type	Design Condition	Qty.
1	Absorber Module	Spray/tray	1,060,000 acfm	1
2	Recirculation Pump	Horizontal centrifugal	31,500 gpm	4
3	Bleed Pump	Horizontal centrifugal	650 gpm	2
4	Oxidation Air Blower	Centrifugal	5600 scfm	2
5	Agitators	Side entering	25 hp motor	6
6	Formic Acid Storage Tank	Vertical, diked	1,000 gal	1
7	Formic Acid Pumps	Metering	0.1 gpm	2

Byproduct Dewatering

Equipment No.	Description	Type	Design Condition	Qty.
6	Gypsum Stacking Pump	Horizontal centrifugal	750 gpm	2
7	Gypsum Stacking Area		42 acres	1
8	Process Water Return Pumps	Vertical centrifugal	500 gpm	2
9	Process Water Return Storage Tank	Vertical, lined	200,000 gal	1
10	Process Water Recirculation Pumps	Horizontal centrifugal	500 gpm	2

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Not Applicable

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Qty.
1	Stack	Reinf. concrete, two FRP flues	60 fps exit velocity 480 ft high x 19 ft dia. (flue)	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty.
1	435 MW Turbine Generator		4500 psig, 1100°F/1100°F/ 1100°F	1
2	Bearing Lube Oil Coolers	Shell & tube	-	2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop	-	1
4	Control System	Electro-hydraulic	1600 psig	1
5	Generator Coolers	Shell & tube	-	2
6	Hydrogen Seal Oil System	Closed loop	-	1
7	Generator Exciter	Solid state brushless	-	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Cooling Tower	Mech draft	160,000 gpm 95°F to 75°F	1
2	Circ. Water Pumps	Vert. wet pit	80,000 gpm @ 80 ft	2

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

ACCOUNT 10A BOTTOM ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Economizer Hopper (part of Boiler scope of supply)			4
2	Bottom Ash Hopper (part of Boiler scope of supply)			2
3	Clinker Grinder		10 tph	2
4	Pyrites Hopper (part of Pulverizer scope of supply included with Boiler)			6
5	Hydroejectors			13
6	Economizer/Pyrites Transfer Tank		40,000 gal	1
7	Ash Sluice Pumps	Vertical, wet pit	1000 gpm	2
8	Ash Seal Water Pumps	Vertical, wet pit	1000 gpm	2

ACCOUNT 10B FLY ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Fabric Filter Hoppers (part of FF scope of supply)			24
2	Air Heater Hopper (part of Boiler scope of supply)			10
3	Air Blower		1800 cfm	2
4	Fly Ash Silo	Reinf. concrete	890 tons	1
5	Slide Gate Valves			2
6	Wet Unloader		30 tph	1
7	Telescoping Unloading Chute			1

3.3.14 Conceptual Capital Cost Estimate Summary

The summary of the conceptual capital cost estimate for the 400 MW ultra-supercritical PC plant is shown in Table 3.3-3. The estimate summarizes the detail estimate values that were developed consistent with Section 9, "Capital and Production Cost and Economic Analysis." The detail estimate results are contained in Appendix E.

Examination of the values in the table reveal several relationships that are subsequently addressed. The relationship of the equipment cost to the direct labor cost varies for each account. This variation is due to many factors including the level of fabrication performed prior to delivery to the site, the amount of bulk materials represented in the equipment or material cost column, and the cost basis for the specific equipment (degree of field fabrication required for items too large to ship to the site in one or several major pieces). Also note that the total plant cost ($/kW) values are all determined on the basis of the total plant net output. This will be more evident as other technologies are compared. One significant change compared to the other plants is that, unlike all of the other technologies, all of the power is generated from a single source, the steam turbine. As a result, the economy of scale influence is greatest for this plant.

Table 3.2-3

Client: DEPARTMENT OF ENERGY
Report Date: 14-Aug-98 08:24 AM
Project: Market Based Advanced Coal Power Systems

TOTAL PLANT COST SUMMARY

Case: Ultracritical PC
Plant Size: 399.7 MW,net **Estimate Type:** Conceptual **Cost Base (Jan)** 1998 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor		Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies		TOTAL PLANT COST	
				Direct	Indirect				Process	Project	$	$/kW
1	COAL & SORBENT HANDLING	6,617	1,951	5,042	353		**$13,962**	1,117		3,016	**$18,095**	45
2	COAL & SORBENT PREP & FEED	8,283		2,590	181		**$11,054**	884		2,388	**$14,326**	36
3	FEEDWATER & MISC. BOP SYSTEMS	16,924		7,397	518		**$24,839**	1,987		6,232	**$33,059**	83
4	PC BOILER & ACCESSORIES											
4.1	PC Boiler	58,543		23,892	1,672		**$84,107**	6,729		9,084	**$99,919**	250
4.2	Open											
4.3	Open											
4.4-4.9	Boiler BoP (w/FD & ID Fans)	3,076		1,014	71		**$4,160**	333		449	**$4,942**	12
	SUBTOTAL 4	*61,618*		*24,906*	*1,743*		***$88,267***	*7,061*		*9,533*	***$104,861***	*262*
5	FLUE GAS CLEANUP	32,690		18,332	1,137		**$52,159**	4,173		5,289	**$61,621**	154
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A		N/A								
6.2-6.9	Combustion Turbine Accessories											
	SUBTOTAL 6											
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A		N/A								
7.2-7.9	HRSG Accessories, Ductwork and Stack	9,202	271	6,824	478		**$16,774**	1,342		2,809	**$20,925**	52
	SUBTOTAL 7	*9,202*	*271*	*6,824*	*478*		***$16,774***	*1,342*		*2,809*	***$20,925***	*52*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	34,999		5,766	404		**$41,169**	3,294		4,446	**$48,909**	122
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	11,797	359	6,470	453		**$19,079**	1,526		3,548	**$24,153**	60
	SUBTOTAL 8	*46,796*	*359*	*12,236*	*857*		***$60,248***	*4,820*		*7,994*	***$73,062***	*183*
9	COOLING WATER SYSTEM	7,658	3,984	7,241	507		**$19,390**	1,551		3,735	**$24,676**	62
10	ASH/SPENT SORBENT HANDLING SYS	5,721	76	10,462	732		**$16,991**	1,359		2,782	**$21,132**	53
11	ACCESSORY ELECTRIC PLANT	9,164	2,859	7,797	546		**$20,365**	1,629		3,606	**$25,600**	64
12	INSTRUMENTATION & CONTROL	6,138		5,089	356		**$11,584**	927		1,949	**$14,459**	36
13	IMPROVEMENTS TO SITE	1,877	1,079	3,759	263		**$6,978**	558		2,261	**$9,798**	25
14	BUILDINGS & STRUCTURES		14,976	17,960	1,257		**$34,193**	2,735		9,232	**$46,161**	115
	TOTAL COST	**$212,688**	**$25,555**	**$129,634**	**$8,928**		**$376,805**	**$30,144**		**$60,825**	**$467,774**	**1170**