NEW COAL-FIRED POWER PLANT PERFORMANCE AND COST ESTIMATES

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PREPARED BY

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1. INTRODUCTION

On behalf of Perrin Quarles Associates, Inc. (PQA), Sargent & Lundy, L.L.C. (S&L) developed for the EPA estimates of performance and order-of-magnitude costs of conventional pulverized coal (PC) and integrated gasification combined cycle (IGCC) power plants. The estimates cover a range of coals and plant sizes. PC analyses consider plant sizes of 400, 600, and 900 MW gross, and subcritical (subC), supercritical (SC), ultra-supercritical (USC), and advanced ultra-supercritical (AUSC) steam cycles, on greenfield sites. Coal types evaluated are Illinois bituminous No. 6, Texas lignite, and Powder River Basin (PRB). IGCC plant analyses are based on the same three coals, at a 600-MW net plant size.

This report summarizes the S&L estimates of performance, total installed cost (TIC), and operations and maintenance (O&M) cost for conventional PC power plants and for IGCC plants. The Appendixes provided include the details of these estimates.

The TIC as developed in this report includes cost escalation and interest during construction (IDC). Sufficient detail is provided to derive overnight costs, excluding escalation, with or without IDC. All costs in this report are based on mid-2008 market conditions, and are expressed in 2008 U.S. dollars, and therefore, likely reflect a historical peak in U.S. and global costs for power plant equipment, materials, labor, services, etc. Any subsequent moderation of market price levels that may have occurred - in connection with the global economic recession, which commenced in 2008 - is not reflected in this report.

2. PC POWER PLANT PERFORMANCE ESTIMATES

2.1 THERMAL CYCLES

Performance is compared for four PC plant types, with the steam conditions shown in Table 2-1, representing subC, SC, USC, and AUSC thermal cycles. These steam conditions are considered representative of current market offerings in the U.S., except for the AUSC plant. Materials and equipment for the AUSC thermal cycle require further development and are not likely to be constructed in the U.S. in the near future.

Table 2-1. Cycle Conditions Used for Performance Estimates

Plant Type	Main Steam Pressure (psia)	Main Steam Temperature (°F)	Reheat Steam Temperature (°F)
subC	2535	1050	1050
SC	3690	1050	1100
USC	3748	1100	1100
AUSC	4515	1300	1300

Steam turbines considered in the performance analyses include HP, IP, and LP sections configured in a tandem-compound arrangement, consisting of one HP, one IP, and opposed-flow LP turbines. The number of LP opposed-flow turbines varies based on size of the power plant. The 400-, 600-, and 900-MW plants were simulated with two, four, and six opposed-flow LP turbines, respectively. The steam turbine drives a single 3600-rpm electric generator.

Thermal cycles are based on a modified Rankine cycle, which uses feedwater heaters supplied with extraction steam from various stages of the turbines to preheat boiler feedwater prior to its entering the steam generator (boiler). The number of heaters considered in the performance analyses represents designs typically seen in commercial construction of U.S. power plants, and is a tradeoff between thermal efficiency and capital costs.

The subC case uses seven feedwater heaters, including one direct-contact type (Appendix C). Heaters 1-4 are supplied with steam extracted from the LP turbine; heater 5 is the deaerator, using steam from the IP turbine exhaust; heater 6 is supplied with IP turbine extraction steam; and heater 7 is supplied with HP turbine exhaust steam.

Both the SC and the USC cases involve eight feedwater heaters (Appendix C), with a distribution similar to the subC case except that the extra heater (8) is supplied with extraction steam from the HP turbine. The heater configurations used for the SC and USC cases are commonly referred to as a *HARP* system, which is a Heater Above the Reheat Point of the turbine steam flow path.

Boiler feedwater is pressurized with a single HP boiler feedwater pump (BFP), powered by an electric drive for the 400- and 600-MW cases and a steam turbine drive for the 900-MW case. For steam turbine-driven cases, the exhaust is directed to the LP turbine condenser. A motor-driven BFP is used for the 400- and 600-MW plant sizes because advances in LP turbine design have led to increased efficiency and availability in recent years, while the cost of larger electric motors has decreased.

The plant cooling system uses mechanical-draft cooling towers with a circulating water temperature rise of 20°F. The condensers are evaluated as multi-flow units, one per each two-flow LP unit.

2.2 MATERIAL HANDLING

The material handling equipment electrical loads include items such as intermittent rail car unloading, conveyors and crushers. The electrical demand is intermittent and therefore an average load is used for auxiliary power consumption estimates.

The ash handling system encompasses equipment required to remove ash from the boiler, economizer, air heater, baghouse, and wet electrostatic precipitator (ESP) collection systems. Conveying equipment electrical loads include LP compressors, drag chains, fans, and conveyors. The average electrical load required by intermittent operation of the equipment is considered in the auxiliary power requirements.

2.3 BOILER SYSTEM

The total number of pulverizers (including one spare) and their associated power requirement is based on plant size and coal type. The 400-MW plant uses five pulverizers for bituminous and PRB cases, and six for lignite; the 600-MW plant uses six pulverizers for bituminous and PRB, and seven for lignite; and the 900-MW plant uses seven pulverizers for bituminous and PRB, and eight for lignite.

Estimated boiler performance is based on a balanced-draft unit operating with low-NO_X combustion systems and a submerged flight conveyor system for bottom ash removal. Steam is heated in the primary and secondary superheater sections and one reheater section. An economizer preheats feedwater prior to its entering the boiler water walls. Combustion air is preheated with one trisector air preheater in the 400-MW case and with two in the 600- and 900-MW cases.

Combustion air is delivered to the boiler by forced draft (FD) and primary air (PA) fans. Induced draft (ID) fans are used to transfer combustion gases through a flue gas desulfurization (FGD) system, baghouse, and stack. The 400-MW case uses a fan arrangement of 1 PA/1 FD/1 ID, and the 600-and 900-MW cases use a 2 PA/2 FD/2 ID fan arrangement (axial ID fans for 900-MW case). Fan power requirements are based on the fan arrangements, the estimated gas flows for each specific coal case, and the specific environmental equipment for each case.

2.4 ENVIRONMENTAL CONTROLS

NO_X formed in the boiler furnace is converted to nitrogen and water by catalytic reaction with ammonia in a selective catalytic reduction reactor (SCR). The pressure drop incurred by flue gas flowing through the SCR is accounted for in the fan power requirements.

SO_2 and SO_3 produced during the combustion of coal, and SO_3 formed in the SCR, are removed from the flue gas with a wet FGD system, wet ESP, or spray dryer absorber. The type of FGD is dependent on the coal burned, permitting requirements, and economic factors. For this conceptual performance estimate, the bituminous and lignite cases are both evaluated with wet FGD, whereas the PRB case is evaluated with spray dryer absorbers. A wet ESP is included to mitigate H_2SO_4 emissions for the bituminous coal case; using one wet ESP in the 400-MW case, two for the 600-MW case, and three for 900-MW case. PRB fuel cases are evaluated with one spray dryer absorber module for the 400-MW case, two for the 600-MW case, and three for the 900-MW case. All FGD power requirements related to limestone or lime preparation and conveyance, calcium sulfate product transfer and de-watering and general FGD operation are included in the auxiliary power requirements. Additionally, the pressure drop incurred by flue gas flowing through the absorbers is accounted for in the ID fan requirements.

Ash particles entrained with flue gas leaving the boiler are removed with a fabric filter baghouse system. Flue gas pressure drop through the baghouse is accounted for in the ID fan power requirements. Power required to operate the baghouse, such as compressor power for back-pulsing, is also included in auxiliary power requirements. One baghouse is included for the 400-MW case, two for 600-MW case, and three for the 900-MW case.

Mercury removal is achieved by activated carbon injection (ACI - brominated) into the flue gas and by mercury-bound particulate capture in the baghouse for the PRB and lignite cases. The bituminous case does not include ACI because the majority of the mercury is in the ionic form and is captured in the wet FGD system. The inherent capture of mercury in the bituminous case is due to significant levels of chloride and its ability to generate ionic mercury.

Results from the performance estimate analyses, net plant heat rate and net plant efficiency, are summarized in Table 2-2 and Table 2-3, below. Coal heating value, as used in the heat rate calculation, is the higher heating value (HHV), which accounts for all heat generated by combustion of the coal, including the heat of condensation of any water formed during the combustion process. Plant size, represented by gross generator output in megawatts, includes auxiliary power used internally by the plant. Performance calculations are based on ambient conditions of 59°F, 60% relative humidity, and sea level elevation. Details of the performance analyses, including heat rate calculations and air emissions, are presented in Appendix A.

Table 2-2. PC Performance Estimates Reported as Net Heat Rate (Btu/kWh)

	MW Gross (Btu/kW net)								
	400	600	900	400	600	900	400	600	900
Plant Type	**Bituminous**			**PRB**			**Texas Lignite**		
subC	9,349	9,302	9,291	9,423	9,369	9,360	9,963	9,912	9,901
SC	9,058	9,017	8,990	9,128	9,080	9,057	9,647	9,603	9,576
USC	8,924	8,874	8,855	8,993	8,937	8,921	9,502	9,449	9,430
AUSC	8,349	8,305	8,279	8,414	8,363	8,341	8,882	8,834	8,808

Table 2-3. PC Performance Estimates Reported as Net Plant Efficiency (100%)

	MW Gross (η% net)								
	400	600	900	400	600	900	400	600	900
Plant Type	**Bituminous**			**PRB**			**Texas Lignite**		
subC	36.5	36.7	36.7	36.2	36.4	36.5	34.2	34.4	34.5
SC	37.7	37.8	38.0	37.4	37.6	37.7	35.4	35.5	35.6
USC	38.2	38.4	38.5	37.9	38.2	38.2	35.9	36.1	36.2
AUSC	40.9	41.1	41.2	40.6	40.8	40.9	38.4	38.6	38.7

The data presented in Table 2-2 and Table 2-3 and the figures below show the effects of plant scale, fuel type, and thermal cycle on the net plant heat rate and efficiency. Plants exhibit improved performance as the gross generation capacity is increased, which is the result of efficiencies of scale. These efficiencies are derived from a plantwide reduction in heat and friction process losses per unit of gross power generated.

Plant efficiency is strongly affected by fuel moisture content. As the fuel is varied from bituminous to PRB and lignite, plant performance decreases due to the corresponding increase in coal moisture content. Also note that although the sulfur content of PRB is significantly lower than that of bituminous, thus allowing PRB to use a spray dryer FGD with its lower auxiliary power requirements, the adverse effects of higher PRB moisture content on boiler efficiency and plant heat rate more than offset PRB reduced FGD auxiliary power load.

The various thermal cycles affects plant performance by increasing the pressure and temperature of steam going to the steam turbine-generator. The increase in steam conditions (primarily the higher temperature) provides more energy that can be converted to shaft power in the steam turbine per pound of fuel combusted in the boiler. A comparison of the first three types of thermal cycle evaluated reveals that the subC to SC transition increases efficiency by approximately 1.2 percentage points at the 900-MW scale. The change in performance between SC and USC is about half of the initial subC to SC transition. The smaller increase is due primarily to the fact that only reheat temperature was increased in the transition to the USC cycle. The AUSC plant performance provides insight into potential efficiencies that may be realized by higher temperature designs. At the 900-MW scale, the transition from subC to AUSC could provide an approximate 4.4 percentage points increase in overall efficiency. The large increase in efficiency results from raising both the steam pressure and the main and reheat steam temperatures significantly above the values used for either the SC or USC cycles.

Figure 2-1. Bituminous Plant Performance Represented by Net Heat Rate

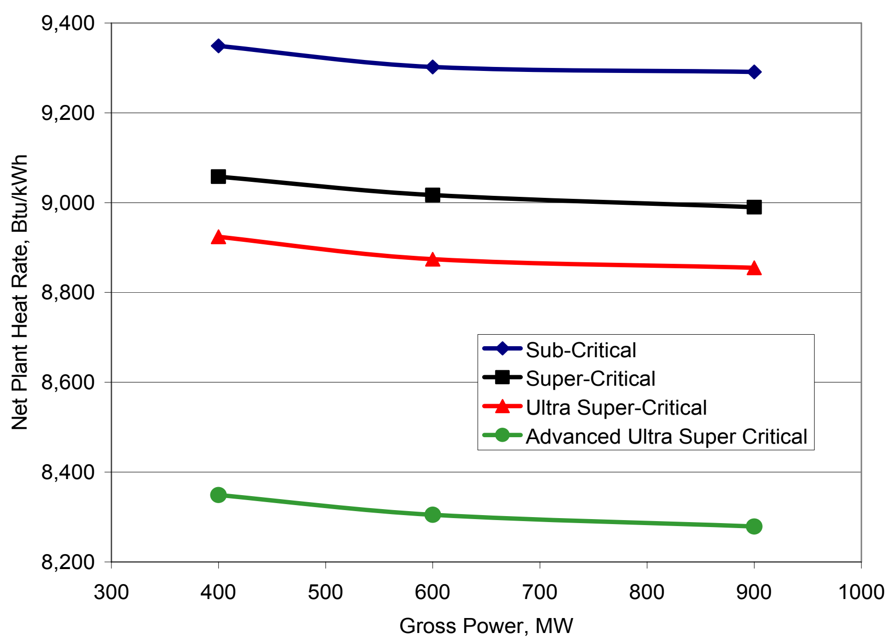


Figure 2-2. PRB Plant Performance Represented by Net Heat Rate

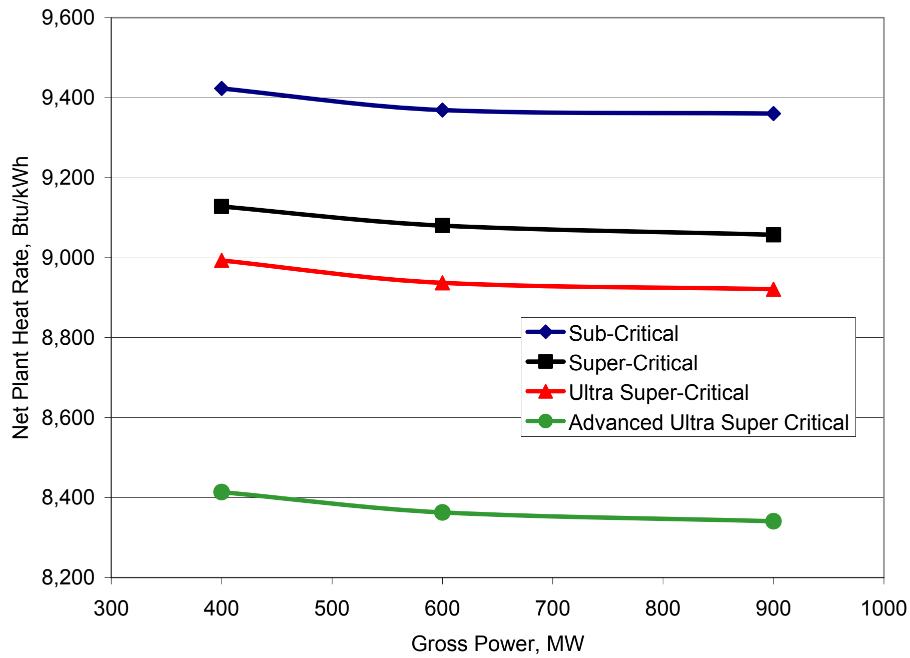
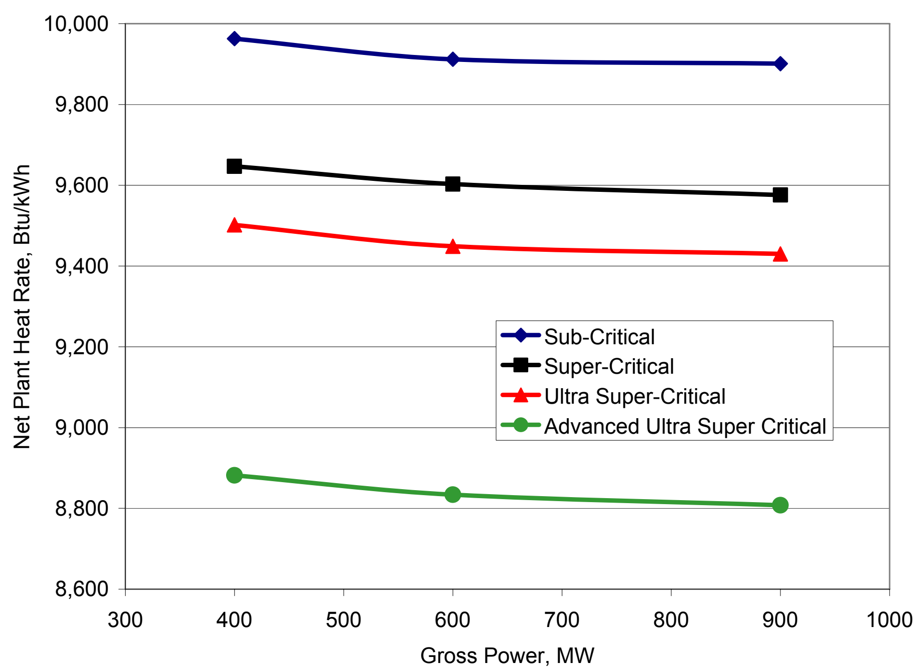


Figure 2-3. Lignite Plant Performance Represented by Net Heat Rate



3. PC POWER PLANT CAPITAL, FIXED, VARIABLE, AND TOTAL PROJECT COST ESTIMATES

3.1 COST ESTIMATE METHODOLOGY

Capital, fixed, and variable O&M costs are estimated based on 2008 market conditions and expressed in 2008 U.S. dollars. Plant conceptual designs are based on a greenfield site. Actual project capital costs may deviate significantly due to differences in the particular technologies chosen, the region where the plant is built, and the Owner's financing strategy. Fixed O&M costs are based on specific equipment maintenance requirements, operating and administrative labor, and industry standards. Variable O&M cost is primarily affected by changes in waste generation and consumables such as reagents, water, and catalysts.

Different coal types, with differing moisture, sulfur, and ash contents, can have a significant impact on plant design and cost. Lower-rank coals (PRB and lignite), with their lower heating values, require higher fuel feed rates and need larger or multiple pieces of equipment to obtain the same gross generation as a bituminous fired plant. Higher coal feed rate particularly affects the coal handling and pulverizer systems. For lignite, some of the additional costs of higher feed rate may be offset because such plants generally are associated with mine-mouth sites and do not require rail car dumpers or a loop track. Higher-ash coals, particularly lignite, increase the amount of ash produced and the associated cost of equipment to remove, cool, and transport the ash.

The use of higher moisture coals (PRB and lignite) reduces boiler efficiency because water in the coal is vaporized during the combustion process and the heat of vaporization is not recovered. The significant amount of heat used to vaporize water in the coal reduces the amount of heat available to generate steam in the boiler. Because higher moisture coals exhibit a lower heating value per pound of fuel, the overall size of the boiler must be increased to accommodate the increased amount of coal and air required per kilowatt of power produced. Likewise, lower-rank coals produce more flue gas per British thermal unit (Btu) of coal burned, and this increases the cost of fans (PA, FD, ID), which transport combustion air and flue gas through the boiler and pulverizers, flue gas ductwork, SCR, baghouse, FGD, and chimney.

The higher steam pressures and temperatures of advanced thermal cycles generally increase costs for the boiler, steam turbine (primarily HP), feedwater heaters, pumps, valves, and the associated piping. Either thicker-walled tubing, headers, and piping or more creep- and corrosion-resistant steels and alloys must be used, at greater expense. BFP motor or steam turbine drive costs are also increased at higher pressures.

Emission of sulfur oxides (SO_2, SO_3) produced by the combustion of coal is controlled to an assumed permit limit by the FGD system. Higher-sulfur coal increases FGD costs due to the impacts of higher materials throughput. Items affected range from pumps, motors, and piping, to limestone preparation and gypsum handling equipment. With wet FGD there is also the requirement for a corrosion resistant wet chimney stack/liner due to the saturated moisture condition of flue gas leaving the FGD. Higher-sulfur coals also increase the formation of sulfuric acid mist, which is captured in a wet ESP to meet environmental regulations. Material, transport and landfill costs are also affected by the increased material handling requirements of higher-sulfur coals.

Removal of mercury from flue gas is achieved by ACI and subsequent mercury-bound particulate capture in the baghouse for the PRB and lignite cases. The bituminous case does not include ACI because most of the mercury is in ionic form and is captured in the wet FGD system. For ACI-baghouse cases, fixed O&M cost includes the filter bag replacement. Variable O&M cost is a function of the mercury content of the coal, which drives the costs of ACI sorbent, material transport, and landfill.

The AUSC analysis does not include capital or O&M cost estimates. Commercial development of AUSC technology in the U.S. stalled after the original units were built in the 1950s (Eddystone Unit 1 (5000 psi / 1200/1050/1050F) and Philo Unit 6 (4500 psi / 1150/1050/1000F)). This lack of development was primarily the result of economic factors. AUSC boiler pressure parts and related equipment pose a cost risk because of the need for very expensive materials, such as nickel-based super-alloys in their construction. Such materials are necessary at the high AUSC steam temperatures to handle high-sulfur coals and cycling operations. AUSC boilers can be manufactured today, but the economic risks associated with this unproven technology in the current market, outweigh the higher efficiencies to be gained. Steam turbines, on the other hand, are not exposed to the highly corrosive environments that boilers must endure and therefore, present less economic risk for long-term operation at AUSC temperatures. Overall, the cost of an AUSC boiler may actually become similar to a more conventional unit when all other items are accounted for, because the more efficient cycle requires less material throughput per kilowatt-hour generated. The higher efficiency would reduce the capacity requirements and physical sizes of various pieces of equipment, possibly lowering the overall cost of an AUSC plant. The performance of more advanced alloys is being actively investigated in the U.S., Western Europe, and Japan. If these developments are successful, they might become economic for commercial use in future advanced PC plants.

3.2 CAPITAL COSTS

The TIC as conceptually estimated for this report, includes all costs associated with constructing and financing a new coal-based power plant. Labor rate is based on conditions in the Gulf Coast.

In addition to the direct costs of structures, equipment, materials, labor, etc (Appendix B), the TIC includes the following: indirect project costs, contingency, Owner's costs, operating spare parts, escalation, and IDC. Generally, these additional costs vary significantly from Owner to Owner. Therefore, the estimated TIC values used in this report are intended to provide only a reasonable range of total project costs, with an accuracy of ±30%.

Indirect project costs cover an architect and engineer's (AE) services, which include engineering, construction management, procurement expediting, startup, and commissioning. Contingency is based on a fixed percentage of 15% for the PC plants. Owner's costs are assumed to be 3%, and the operating and spare parts are accounted for as 1%. Project cost escalation for PCs is based on an annual rate of 4%, a project start date of January 2009, construction beginning by January 2011, and commercial operation by December 2013. Separate spend rate curves are developed for equipment, materials, labor, and indirect expenses. IDC is based on a 6% annual rate.

The use of an engineer, procure, and construct (EPC) lump-sum contract could increase the estimated TIC by 10-15%. The increased fees would be attributable to the EPC Contractor's fees and contingency costs associated with its exposure to financial risk stemming from unanticipated escalation in the market price for resources required for the project, as well as its liability for project schedule and performance.

The TIC estimates for the various cases are presented in Table 3-1. The costs are all-inclusive, representing all costs that may be incurred at completion of a PC project in 2013. The results indicate that the PRB-based plant is least expensive on a dollar per net kilowatt basis, followed by the bituminous and the lignite-based plants. This ordering of costs derives from characteristics of the coal types and the associated effects on the plant design. Compared with the PRB case, a plant designed for the bituminous coal as used in this report will include higher capital cost items, such as a wet FGD, wet ESP, and acid-resistant chimney liner, and its net kilowatt power output will be reduced due to a higher auxiliary power requirement. Although PRB coal requires a larger boiler and coal handling system than bituminous, due to PRB's greater fuel input per kilowatt of generation, that extra cost does not outweigh the even higher cost of wet FGD and wet ESP equipment associated with the high-sulfur bituminous case. Lignite requires the same type of emission control equipment as the bituminous case, excepting wet ESP, because of its significant sulfur content, and lignite necessitates an even larger boiler than PRB because it has the lowest heating value of the three fuels.

Table 3-1. Total Installed Cost Estimates (±30%) for Various PC Plants ($2008/kW Net)

	MW Gross ($/kW net)								
	400	600	900	400	600	900	400	600	900
Plant Type	**Bituminous**			**PRB**			**Texas Lignite**		
subC	4,523	3,844	3,190	4,186	3,555	2,951	4,760	4,045	3,357
SC	4,686	3,982	3,262	4,332	3,679	3,015	4,931	4,190	3,433
USC	4,835	4,109	3,362	4,466	3,792	3,105	5,090	4,325	3,540

4. 600-MW NET IGCC PERFORMANCE ESTIMATES

Estimated performance and total installed cost are compared for an IGCC plant and a conventional PC-fired SC plant. For this comparison, performance and costs were developed at 600-MW net output for both plants, and for the same three coal types as used in the PC-fired analysis presented in Sections 2 and 3.

4.1 IGCC CONCEPTUAL DESIGN

The assumed design basis for IGCC incorporates current industry trends in plant configuration, and uses the same site conditions as described for the PC plant analyses. The IGCC plant conceptual design is based on two gasification and cleanup trains supplying synthesis gas (syngas) fuel to two F-Class combustion turbine generators (CTGs), two heat recovery steam generators (HRSGs), and one steam turbine (STG). Each gasification train includes an air separation unit (ASU). Plant integration includes the transfer of steam, cooling water, and gases between the gasification island and the combined cycle power block. The gasification island is modeled with process simulation software (AspenPlus™); the power block is modeled with GateCycle™. The gasifier is based on Shell's entrained flow, oxygen-fired technology. The use of one gasification technology in this analysis is recognized as an approximation and a convenience, as other gasifiers in fact perform differently on some of the coal types considered. The selected gasifier does have a history of performance on coals similar to the three types used in this analysis, and a significant amount of performance information available in the open literature [Ref. 1].

4.2 AIR SEPARATION UNIT

The ASU produces oxygen and nitrogen streams used in the IGCC plant. The main liquid oxygen (O_2) stream is pumped to high pressure and then vaporized prior to sending it to the gasifier. A smaller, low-pressure O_2 stream is used in the Claus sulfur removal unit. The majority of the nitrogen (N_2) is compressed and sent back to the CTG as a syngas diluent. The remaining N_2 is used for coal drying, pneumatic transport of coal to the gasifier, and other process purposes. Integration between the ASU and the CTG air compressor involves the supply of 35% of the air to the ASU main air compressor (MAC) by a high-pressure extraction line from the CTG. This percentage of air extraction has been the norm in recent IGCC conceptual designs; but in practice, integration at 0-100% has been used in actual IGCC plants. Because the ASU requires a significant amount of power for air compression, full integration between the CTG and ASU can improve IGCC plant efficiency. But the use of full CTG-ASU integration can potentially reduce the availability of the plant and increase the complexity of the system at start up if a smaller, stand alone air compressor is not included in the plant design.

4.3 COAL HANDLING

Coal handling and milling for the IGCC are based on conventional equipment. Because the selected gasifier operates on a dry coal feed that is pneumatically injected into the gasifier, the coal must be dried to a specific moisture content to prevent flow instability. Coal is dried by pre-heated air as it flows through pulverizers. The air used for coal drying is heated with medium pressure (MP) steam produced in the gasification island. Drying air is supplemented with excess N_2 from the ASU to reduce its oxygen concentration and prevent coal fires. Dried pulverized coal is separated from its transport air in a baghouse and stored in silos. It then flows to lock-hoppers and is pneumatically injected into the gasifiers with high pressure (HP) N_2. The performance analysis is based on drying bituminous coal to 2%wt moisture content, PRB to 6%wt, and lignite to 7%wt. Low-moisture content in coal provides for effective transport of pulverized coal through the injection system.

4.4 GASIFICATION ISLAND

High-temperature syngas, produced by reacting the coal with oxygen and steam in the gasifier, is initially quenched by cooled syngas that has been recompressed and recycled back to the gasifier. After the gasifier, syngas is further cooled in a syngas cooler, generating steam. The syngas cooler provides both MP saturated steam and HP superheated steam. This HP steam is mixed with HP steam generated in the HRSG as main steam to the HP STG. MP steam is used in the ASU, the sulfur removal unit, and for coal drying. Additional LP steam is produced by further cooling of the syngas and is used in the ASU, acid gas removal unit, and sour water stripper.

The syngas particulate cleanup portion of the plant uses a high-temperature cyclone, candle filter, and low-temperature water scrubber. The cyclone and candle filter remove the majority of particulates, while the very fine particles are removed in a counter-flow water scrubber. Approximately half of the syngas is compressed and recycled back to the gasifier for quenching after flowing through the cyclone and candle filter. The remaining syngas enters the water scrubber, which removes the remaining fine particulates and absorbs most of the ammonia, hydrochloric acid, and other ionic compounds generated in the gasifier.

The majority of the ash present in the coal is liquefied in the gasifier and flows down through the bottom of the vessel into a water quench system. Solidified slag is removed via a crushing, cooling, and depressurization process before separation from the water for temporary storage and transport.

After particulate cleanup the syngas is processed in an acid gas removal (AGR) system to remove sulfur. Sulfur is present primarily in the form of hydrogen sulfide (H_2S) and carbonyl sulfide (COS). The AGR converts carbonyl sulfide to hydrogen sulfide by reacting it with steam in a catalytic reactor. H_2S is separated from the syngas by preferential absorption in a gas-liquid absorption column.

Mercury is removed from the syngas by chemisorption onto the surface of activated carbon pellets in a packed bed vessel through which the syngas flows.

H_2S separated from the syngas in the AGR is converted to elemental sulfur in a Claus unit. Approximately a third of the H_2S is reacted with O_2 to generate SO_2. The remaining H_2S is then catalytically reacted with the SO_2 to form elemental sulfur. Unconverted gases are recycled back to the AGR.

4.5 THERMAL CYCLE

Clean syngas is diluted and reheated before being combusted in the CTG. The diluent consists of steam and N_2. The steam is extracted from the power block, and N_2, which is a product of the ASU, is compressed before mixing with the syngas. Hot exhaust gas from the CTG flows through the HRSG, which preheats feed water and generates main steam and reheat steam for the STG. The thermal cycle is based on conventional combined cycle conditions of 1800 psig/1000°F/1000°F.

The HRSG is configured with an SCR system for NO_X control. NO_X formed during the combustion process is converted back to N_2 by reaction with ammonia over an SCR catalyst.

4.6 PERFORMANCE

IGCC performance results are presented in Table 4-1, providing a comparison between the SC and IGCC cases.

IGCC performs better than conventional SC on all three fuel types, with the difference in performance becoming greater as the fuel moves from bituminous to the higher moisture coals. The higher efficiency of the IGCC on PRB and lignite is primarily due to the ability of the IGCC plant to pre-dry the coal prior to processing.

IGCC performance in this analysis is lower than that commonly reported for IGCC designs that are fully integrated with respect to air extraction from the CTG compressor for ASU air supply. The difference is primarily due to the increased power consumption of the ASU MAC in this analysis (compressing 65% of the air for the ASU versus extracting 100% of the air supply from the CTG compressor). IGCC units that have actually employed 100% integration are the Buggenum plant in the Netherlands and the Puertollano unit in Spain. They have yielded efficiencies over 42% (HHV basis).

Table 4-1. 600-MW Net SC and IGCC Performance
Reported as Heat Rate (Btu/kWh Net) and Thermal Efficiency (% Net)

	Bituminous		PRB		Lignite	
	SC	IGCC	SC	IGCC	SC	IGCC
Btu/kWh (net)	9,000	8,425	9,063	8,062	9,584	8,515
Thermal efficiency (% met)	37.91	40.50	37.65	42.32	35.60	40.07

For this analysis, the IGCC performance with the PRB coal was more efficient than with the Illinois No. 6 bituminous coal. This is primarily due to the higher reactivity of the PRB coal and a lesser need for oxygen as a reactant in the gasifier. Similar results were reported by Shell in a paper in which they attributed this difference to the constituents of the particular Illinois No. 6 coal [Ref. 2]. Because the ASU consumes a significant amount of power to compress its air feed and oxygen product streams, a decrease in oxygen consumption by the gasification process can significantly reduce total plant auxiliary power requirements, thus increasing efficiency. The amounts of MP and LP steam used by the ASU are also reduced when the oxygen requirement of the gasifier is reduced. Furthermore, with PRB's lower sulfur content the amount of sulfur that has to be processed is significantly lower (COS hydrolysis, AGR, and Claus units affect performance through their steam and cooling demands). The gasification of PRB fuel produces a lower Btu per standard cubic foot (SCF) syngas than a bituminous fuel, which in turn, requires more syngas to be generated to fuel the CTGs and therefore more HP, MP and LP steam is generated to cool the higher mass flow of syngas. And since this analysis has included the use of a syngas cooler that generates superheated HP steam, the effects on the thermal cycle are more pronounced than if a saturated steam were produced. Further, because the PRB coal produces a lower Btu/SCF fuel, less diluent is needed prior to combustion, which reduces both steam and N_2 consumption demands. PRB's higher moisture content has a significant impact on performance because more steam is needed to dry PRB than bituminous, but the increased drying steam load for PRB does not offset the efficiency benefits of its smaller ASU and lower ash and sulfur contents.

IGCC performance on lignite is primarily affected by the fuel's moisture and ash content. The high moisture content requires a significant amount of steam for coal drying, which reduces the percentage of the steam generated in the gasification island that can be supplied to the power block. Lignite's high ash content affects gasifier performance because a considerable amount of heat is consumed to liquefy the ash into a molten slag, reducing the heat available to support endothermic gasification reactions. These negative impacts are partly offset by the highly reactive nature of the lignite, which requires less oxygen than the bituminous case. IGCC plant performance with lignite can be improved if the coal is dried to a lesser extent. Coal's inherent moisture content, and the type of dense, pneumatic feed system used in the design, dictates the required extent of coal drying. This analysis uses a value of 7%wt, which is lower than some estimates, which indicate a 13%wt moisture content is feasible with a similar pneumatic injection system. By increasing the moisture content of the coal fed to the gasifier, the overall IGCC efficiency on lignite would increase due to the reduction in steam demand for the drying process.

An alternative IGCC design that uses a supercritical steam cycle could provide increased plant efficiency for all cases. Two concerns with such a design are that neither a HRSG nor a syngas cooler have been manufactured to operate on a SC steam cycle, and it will likely have significant cost disadvantages. Because a power plant designed around an SC thermal cycle has to take advantage of economies of scale in a competitive marketplace (450 MW or larger SC Class STG), an IGCC plant using an SC system might best be designed around the larger H-Class CTG. An IGCC design based on both an H-Class CTG and SC thermal cycle might benefit from the efficiency of SC steam conditions, but most of the efficiency improvement would likely be provided by the higher efficiency of the H-Class CTG.

5. IGCC PLANT COST ESTIMATES

5.1 COST ESTIMATE METHODOLOGY

Estimated IGCC power plant capital and fixed and variable O&M costs are based on the same principles and conventions used for the conventional PC-fired plants as explained in subsection 3.1, and the same caveats apply. Only those aspects of the IGCC plant that require a difference in the estimating approach are discussed here.

Coal reactivity determines the amount of oxygen necessary to effectively gasify the coal in an IGCC. Of the three coals compared, bituminous is the least reactive, requires the most oxygen, and therefore requires a larger ASU. The ASU constitutes a significant portion of the total plant cost. It directly affects auxiliary power consumption, and its size can therefore substantially affect plant capital and O&M costs.

Higher-moisture coals affect plant costs because the size of the equipment required to transport, mill, and dry the lower heating value fuel is increased. These coals also reduce power output from the plant as more steam is required to dry the fuel.

Higher ash coals increase costs associated with the equipment required to remove, cool, and transport the ash. Because ash content is significantly higher for the lignite, a third gasifier is added in the conceptual design to process that coal. A more cost-effective approach would scale-up the size of the gasifiers to handle the extra coal throughput and associated slag, keeping the lignite design at two gasifiers. However, it is difficult to accurately estimate an all-inclusive cost of a new gasifier design without working directly with a vendor on a specific coal. Therefore, the lignite-based IGCC cost may be significantly higher in this analysis than would otherwise be expected, due to the requirements of three standard-size gasifiers, syngas coolers, and associated coal feed and slag handling equipment. O&M costs associated with disposing gasifier slag are assumed to be negligible. Because slag is a vitreous, inert material, quite suitable for use in building products (concrete, shingles, etc.), it is assumed that it would be sold at a price equivalent to transportation costs.

The higher-sulfur bituminous coal requires larger equipment to process the sulfur byproduct. Sections of the plant most significantly affected by higher-sulfur coal are the hydrolysis reactors, the Claus unit, and the AGR. Higher-sulfur coal also requires more steam and electricity for processing the byproduct, which lowers plant thermal efficiency. O&M costs associated with sulfur processing include catalyst and chemical replacement.

Mercury removal from the syngas requires larger packed beds of activated carbon for the higher-mercury content fuels. Mercury capture itself affects O&M cost to some extent due to the necessity of handling the spent sorbent as a hazardous material.

5.2 COST ESTIMATES

The TIC as conceptually estimated for this report, includes all costs associated with constructing and financing a new IGCC power plant. The various elements of TIC for IGCC are the same as for the PC plants as explained in subsection 3.2. Only a few significant differences are discussed here. TIC estimates in this evaluation are intended only to provide a reasonable range of total project costs with an accuracy of ±30%.

The IGCC contingency allowance is based on a fixed 20%, which is higher than the amount used for the PC plants due to the extra risk attributed to development of an IGCC plant. The project escalation amount is based on an annual rate of 4%, a project start date of January 2009, construction beginning by January 2011, and commercial operation by December 2015 for IGCC. IDC for IGCC is based on a 6% annual rate and a seven-year cash flow.

The TIC estimates for 600 MW net SC and IGCC plants are presented in Table 5-1 for comparison. The significant cost difference between the two types of plants can be attributed partly to the risks associated with financing an IGCC, but primarily to the more complex systems and advanced technology used in the IGCC plant.

Table 5-1. Total Installed Cost Estimates (±30%) for SC and IGCC Plants Based on Comparable 600-MW Net Output ($2008/kW Net)

Plant Type	Bituminous	PRB	Lignite
SC	3,641	3,393	4,076
IGCC	4,589	4,652	5,763

6. REFERENCES

1. Eurlings, J. Th. G. M.; B. V. Demkolec, "Process Performance of the SCGP at Buggenum IGCC," Proceedings from the Gasification Technologies Conference, San Francisco, CA, 1999.

2. van der Ploeg, H. J.; T. Chhoa; P. L. Zuideveld, "The Shell Coal Gasification Process for the US Industry," Proceedings from the Gasification Technologies Conference, Washington, DC, 2004.

APPENDIX A

PC POWER PLANT PERFORMANCE AND COST ESTIMATE SPREADSHEETS

PQA Study
Technology Spreadsheet
Efficiency/Heat Rate for New Coal-Fired Power Plants
Subcritical

		Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical
Base set-up for meeting Target BACT limits for NOX & SO2	**UNITS**	**400MW - Subcritical PC, Bituminous**	**400MW - Subcritical PC, Lignite**	**400MW - Subcritical PC, PRB**	**600MW - Subcritical PC, Bituminous**	**600MW - Subcritical PC, Lignite**	**600MW - Subcritical PC, PRB**	**900MW - Subcritical PC, Bituminous**	**900MW - Subcritical PC, Lignite**	**900MW - Subcritical PC, PRB**
Number of BFW Heaters		**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**
Number of FGD Absorbers		**1**	**1**	**1**	**1**	**1**	**2**	**1**	**1**	**3**
Number of wet ESPs		**1**	**0**	**0**	**2**	**0**	**0**	**3**	**0**	**0**
Number of Pulverizers		**5**	**6**	**5**	**6**	**7**	**6**	**7**	**8**	**7**
SO2		**Wet FGD**	**Wet FGD**	**Dry FGD**	**Wet FGD**	**Wet FGD**	**Dry FGD**	**Wet FGD**	**Wet FGD**	**Dry FGD**
NOX		**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**
Primary Particulate Control		**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**
Secondary Particulate Control		**Wet ESP**	**None**	**None**	**Wet ESP**	**None**	**None**	**Wet ESP**	**None**	**None**
Mercury Control		**Inherent**	**ACI-w/BGH**	**ACI-w/BGH**	**Inherent**	**ACI-w/BGH**	**ACI-w/BGH**	**Inherent**	**ACI-w/BGH**	**ACI-w/BGH**
PLANT CONFIGURATION: (Gross-MW)		**1x400**	**1x400**	**1x400**	**1x600**	**1x600**	**1x600**	**1x900**	**1x900**	**1x900**
NO. OF STEAM GENERATORS		1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler
Main Steam Pressure	psig	2535	2535	2535	2535	2535	2535	2535	2535	2535
Main Steam Temperature	°F	1050	1050	1050	1050	1050	1050	1050	1050	1050
Hot Reheat Temperature	°F	1050	1050	1050	1050	1050	1050	1050	1050	1050
NO. OF STEAM TURBINES		1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine
SOx CONTROL:		Wet FGD	Wet FGD	Dry FGD	Wet FGD	Wet FGD	Dry FGD	Wet FGD	Wet FGD	Dry FGD
Uncontrolled SO2 Emission Rate	lb/mmBtu	4.32	2.14	0.52	4.32	2.14	0.52	4.32	2.14	0.52
Target "Permit" SO_2 Emission Rate	lb/mmBtu	0.10	0.08	0.08	0.10	0.08	0.08	0.10	0.08	0.08
SULFUR REMOVAL percent required meet Target "Permit" Rate	%	97.68	96.27	84.76	97.68	96.27	84.76	97.68	96.27	84.76
Typical Maximum SO2 Removal Guarantee from Vendor	%	98.15	97.20	84.76	98.15	97.20	84.76	98.15	97.20	84.76
NOx CONTROL:		SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR
Uncontrolled Rate from Furnace	lb/mmBtu	0.25	0.20	0.20	0.25	0.20	0.20	0.25	0.20	0.20
Target "Permit" NOx Emission Rate	lb/mmBtu	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Specified Design Guarantee from vendor	lb/mmBtu	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
PARTICULATE CONTROL		Baghouse	Baghouse	Baghouse	Baghouse	Baghouse	Baghouse	Baghouse	Baghouse	Baghouse
Target "Permit" Emission Rate	lb/mmBtu	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Mercury Control		Inherent	ACI-w/BGH	ACI-w/BGH	Inherent	ACI-w/BGH	ACI-w/BGH	Inherent	ACI-w/BGH	ACI-w/BGH
Cooling Method		MD-CT	MD-CT	MD-CT	MD-CT	MD-CT	MD-CT	MD-CT	MD-CT	MD-CT
PLANT PERFORMANCE:										
Net Plant Heat Rate, HHV	Btu/net-kWh	9,349	9,963	9,423	9,302	9,912	9,369	9,291	9,901	9,360
Gross Plant Output	**Gross-kW**	**400,000**	**400,000**	**400,000**	**600,000**	**600,000**	**600,000**	**900,000**	**900,000**	**900,000**
Net Plant Output (based on Annual Average Conditions)	Net-kW	359,151	355,843	362,958	539,059	534,133	545,152	828,433	820,750	837,573
Gross Plant Heat Rate, HHV	Btu/gross-kWh	8,394	8,863	8,550	8,358	8,824	8,513	8,552	9,030	8,711
Auxiliary Power	kW	40,849	44,157	37,042	60,941	65,867	54,848	71,567	79,250	62,427
Turbine Heat Rate	Btu/kWh	7,347	7,347	7,347	7,316	7,316	7,316	7,487	7,487	7,487
Primary Fuel Feed Rate per Boiler	lb/hr	288,672	594,036	408,025	431,129	887,181	609,379	661,740	1,361,727	935,335
Primary Fuel Feed Rate per Boiler	Tons/hr	144	297	204	216	444	305	331	681	468
Primary Fuel Feed Rate per Boiler	lb/net-MWh	804	1,669	1,124	800	1,661	1,118	799	1,659	1,117
Full load Heat input to Boiler	mmBtu's/hr	3,358	3,545	3,420	5,015	5,295	5,108	7,697	8,127	7,840
Secondary Fuel Feed Rate	lb/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Secondary Fuel Feed Rate	lb/net-MWh	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lime/Limestone Feed Rate	lb/hr	25,433	13,216	1,920	37,984	19,739	2,867	58,302	30,296	4,401
Lime/Limestone Feed Rate	lb/net-MWh	70.8	37.1	5.3	70.5	37.0	5.3	70.4	36.9	5.3
Ammonia Feed Rate(Anhydrous)	lb/hr	264	210	203	297	314	303	456	482	465
Ammonia Feed Rate	lb/net-MWh	0.736	0.591	0.559	0.552	0.588	0.556	0.551	0.587	0.555
Activated Carbon Injection Rate	lb/hr	0	124	112	0	185	168	0	284	258
Activated Carbon Injection Rate	lb/net-MWh	0.00	0.35	0.31	0.00	0.35	0.31	0.00	0.35	0.31

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		Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical
Base set-up for meeting Target BACT limits for NOX & SO2	**UNITS**	**400MW - Subcritical PC, Bituminous**	**400MW - Subcritical PC, Lignite**	**400MW - Subcritical PC, PRB**	**600MW - Subcritical PC, Bituminous**	**600MW - Subcritical PC, Lignite**	**600MW - Subcritical PC, PRB**	**900MW - Subcritical PC, Bituminous**	**900MW - Subcritical PC, Lignite**	**900MW - Subcritical PC, PRB**
Water Consumption										
Cycle Make-up & Misc. Services	gpm	503	623	403	814	814	814	1225	1225	1225
Cooling Tower/lake make-up	gpm	4,310	4,270	4,355	6,469	6,410	6,542	9,941	9,849	10,051
Total Water	gpm	4,813	4,893	4,759	7,283	7,224	7,356	11,166	11,074	11,275
Water Consumption	gal/net-MWh	804	825	787	811	811	810	809	810	808
FUEL ANALYSIS:		Bituminous	Lignite	PRB	Bituminous	Lignite	PRB	Bituminous	Lignite	PRB
Ultimate Analysis										
Carbon	%	63.75	36.27	50.25	63.75	36.27	50.25	63.75	36.27	50.25
Sulfur	**%**	**2.51**	**0.64**	**0.22**	**2.51**	**0.64**	**0.22**	**2.51**	**0.64**	**0.22**
Oxygen	%	6.88	10.76	13.55	6.88	10.76	13.55	6.88	10.76	13.55
Hydrogen	%	4.50	2.42	3.41	4.50	2.42	3.41	4.50	2.42	3.41
Nitrogen	%	1.25	0.71	0.65	1.25	0.71	0.65	1.25	0.71	0.65
Chlorine	%	0.29	0.00	0.00	0.29	0.00	0.00	0.29	0.00	0.00
Ash	%	9.70	17.92	4.50	9.70	17.92	4.50	9.70	17.92	4.50
Moisture	%	11.12	31.24	27.40	11.12	31.24	27.40	11.12	31.24	27.40
Gross Higher Heating Value (Dulong)	Btu/lb	11,631	5,968	8,382	11,631	5,968	8,382	11,631	5,968	8,382
SORBENT ANALYSIS:										
$CaCO_3$	%	90	90	0	90	90	0	90	90	0
$MgCO_3$	%	5	5	0	5	5	0	5	5	0
CaO	%	0	0	90	0	0	90	0	0	90
Ash/Inerts	%	5	5	10	5	5	10	5	5	10
Moisture	%	0	0	0	0	0	0	0	0	0
STEAM GENERATOR DATA (Per Boiler):										
Theoretical Air	lb/lb-fuel	8.70	4.57	6.39	8.70	4.57	6.39	8.70	4.57	6.39
Theoretical Dry Gas	lb/lb-fuel	9.09	4.87	6.76	9.09	4.87	6.76	9.09	4.87	6.76
Actual Dry Gas	lb/lb-fuel	10.83	5.78	8.04	10.83	5.78	8.04	10.83	5.78	8.04
Excess Air	%	20	20	20	20	20	20	20	20	20
Total Dry Air Flow	lb/lb-fuel	10.45	5.49	7.67	10.45	5.49	7.67	10.45	5.49	7.67
Ambient Air Moisture	lb/lb-lair	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025
Total Air Flow	lb/lb-fuel	10.71	5.63	7.86	10.71	5.63	7.86	10.71	5.63	7.86
Flue Gas Moisture Flow	lb/lb-fuel	0.774	0.666	0.770	0.774	0.666	0.770	0.774	0.666	0.770
Products of Combustion	lb/lb-fuel	11.61	6.45	8.81	11.61	6.45	8.81	11.61	6.45	8.81
Air Heater Leakage	%	5	5	5	5	5	5	5	5	5
Air Heater Inlet Temperature	°F	100	100	100	100	100	100	100	100	100
Infiltration	%	5	5	5	5	5	5	5	5	5
Exit Flue Gas Temperature	°F	310	305	280	310	305	280	310	305	280
Flue Gas Temp. Uncorrected	°F	319	314	288	319	314	288	319	314	288
Flue Gas Flow Rate (per boiler)	lb/hr	3,633,876	4,136,283	3,889,182	5,427,155	6,177,453	5,808,439	8,330,144	9,481,721	8,915,359
Flue Gas Flow Rate	acfm	1,215,293	1,374,332	1,250,000	1,815,027	2,052,537	1,866,858	2,785,886	3,150,422	2,865,435
Combustion Air Flow	lb/hr	3,090,646	3,342,492	3,205,710	4,615,848	4,991,943	4,787,684	7,084,868	7,662,092	7,348,604
Combustion Air Flow	acfm	737,247	797,322	764,694	1,101,070	1,190,784	1,142,060	1,690,033	1,827,725	1,752,945
Stack Flue Gas Temperature	°F	135	140	170	135	140	170	135	140	170
Stack Flue Gas Flow Rate per Flue	acfm	994,411	1,141,406	1,148,550	1,485,142	1,704,666	1,715,344	2,279,545	2,616,478	2,632,877
Radiation Loss	%	0.194	0.194	0.194	0.184	0.184	0.184	0.175	0.175	0.175
Dry Gas Heat Loss	%	5.89	5.96	5.19	5.89	5.96	5.19	5.89	5.96	5.19
Fuel Moisture Loss	%	1.07	5.84	3.62	1.07	5.84	3.62	1.07	5.84	3.62
Hydrogen in Fuel Loss	%	3.89	4.07	4.06	3.89	4.07	4.06	3.89	4.07	4.06
Air Moisture Heat Loss	%	0.237	0.236	0.206	0.237	0.236	0.206	0.237	0.236	0.206
Carbon Loss	%	0.50	0.10	0.10	0.50	0.10	0.10	0.50	0.10	0.10
Unaccounted Loss	%	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Manufacturer's Margin	%	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50

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		Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical
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Total Boiler Loss	%	12.47	17.10	14.07	12.46	17.09	14.06	12.45	17.08	14.05
Boiler Efficiency	%	87.53	82.90	85.93	87.54	82.91	85.94	87.55	82.92	85.95
Total Heat Output from Boiler	mmBtu/hr	2,938.80	2,938.80	2,938.80	4,389.60	4,389.60	4,389.60	6,738.30	6,738.30	6,738.30
Main Steam Flow	lb/hr	2,469,730	2,469,730	2,469,730	3,684,000	3,684,000	3,684,000	5,641,301	5,641,301	5,641,301
STEAM TURBINE/CYCLE DATA (Per Turbine):										
Turbine Back Pressure	in HgA	2	2	2	2	2	2	2	2	2
Steam Turbine Gross Output	kW	400,000	400,000	400,000	600,000	600,000	600,000	900,000	900,000	900,000
LP Turbine Exhaust to Condenser	lb/hr	1,663,778	1,663,778	1,663,778	2,482,394	2,482,394	2,482,394	3,588,894	3,588,894	3,588,894
Exhaust Energy	Btu/lb	1,018.50	1,018.50	1,018.50	1,014.60	1,014.60	1,014.60	1,015.00	1,015.00	1,015.00
Condensate Enthalpy	Btu/lb	69.1	69.1	69.1	69.1	69.1	69.1	69.1	69.1	69.1
Heat Rejection from LP Turbine	mmBtu/hr	1,580	1,580	1,580	2,347	2,347	2,347	3,395	3,395	3,395
BFP Turbine Drive Steam Flow	lb/hr	0	0	0	0	0	0	213,354	213,354	213,354
BFP Turbine Exhaust Enthalpy	Btu/lb	0	0	0	0	0	0	1,056	1,056	1,056
Heat Rejection from BFP Turbine	Btu/hr	0	0	0	0	0	0	202	202	202
Total Heat Rejected to Condenser	mmBtu/hr	1,580	1,580	1,580	2,347	2,347	2,347	3,597	3,597	3,597
Circulating Water Temp. Rise	°F	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Circulating Water Flow	gpm	167,246	167,246	167,246	248,318	248,318	248,318	381,114	381,114	381,114
Number of Cooling Tower Cells		14	14	14	20	20	20	30	30	30
Total Circ. Water Flow	gpm	167,246	167,246	167,246	248,318	248,318	248,318	381,114	381,114	381,114
Service Water Flow	gpm	8,362	8,362	8,362	12,416	12,416	12,416	19,055	19,055	19,055
Total Cooling Water Requirement	gpm	175,608	175,608	175,608	260,734	260,734	260,734	400,169	400,169	400,169
PLANT AUXILIARY POWER:										
Induced Draft Fan Pressure Rise	"wc	44.0	44.0	41.8	44.0	44.0	41.8	44.0	44.0	41.8
Boiler	"w.c	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Econ Outlet to SCR outlet	"w.c	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
SCR Outlet to AH Outlet	"w.c	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
AH Outlet to ESP Outlet	"w.c	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AH/ESP Outlet to COHPAC or Dry FGD/BH Outlet	"w.c	8.0	8.0	16.0	8.0	8.0	16.0	8.0	8.0	16.0
COHPAC/Dry FGD BH Outlet to stack	"w.c	0.0	0.0	2.0	0.0	0.0	2.0	0.0	0.0	2.0
ID inlet to Wet FGD outlet	"w.c	8.0	8.0	0.0	8.0	8.0	0.0	8.0	8.0	0.0
Wet FGD outlet to stack outlet	"w.c	4.0	4.0	0.0	4.0	4.0	0.0	4.0	4.0	0.0
Total ID fan static pressure	"w.c	40.0	40.0	38.0	40.0	40.0	38.0	40.0	40.0	38.0
Percent Total Air to FD Fan	%	70	70	70	70	70	70	70	70	70
Forced Draft Fan Pressure Rise	"wc	20	20	20	20	20	20	20	20	20
Percent Total Air to PA Fan	%	30	30	30	30	30	30	30	30	30
Primary Air Fan Pressure Rise	"wc	40	40	40	40	40	40	40	40	40
Percent Total Air to SA Fan	%	0	0	0	0	0	0	0	0	0
Secondary Air Fan Pressure Rise	"wc	15	15	15	15	15	15	15	15	15
Condensate P/P	%	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
Circulating Water P/P	%	0.50	0.50	0.50	0.50	0.50	0.50	0.51	0.51	0.51
Cooling Towers	%	0.72	0.72	0.72	0.69	0.69	0.69	0.69	0.69	0.69
Feedwater P/P	%	2.30	2.30	2.30	2.30	2.30	2.30	0.00	0.00	0.00
Subtotal CWS	%	3.89	3.89	3.89	3.85	3.85	3.85	1.56	1.56	1.56
Forced Draft Fan	%	0.36	0.39	0.37	0.36	0.39	0.37	0.37	0.40	0.38
Induced Draft Fan	%	2.09	2.36	1.86	2.08	2.35	1.86	2.13	2.41	1.90
Primary Air Fan	%	0.31	0.34	0.32	0.31	0.34	0.32	0.32	0.34	0.33
Pulverizer	%	0.52	1.07	0.73	0.52	1.07	0.73	0.53	1.09	0.75
Fuel Handling	%	0.13	0.23	0.17	0.13	0.23	0.17	0.13	0.23	0.17
Ash Handling	%	0.20	0.62	0.14	0.20	0.62	0.14	0.20	0.64	0.15
Wet ESP for H2SO4 collection	%	0.15	0.00	0.00	0.15	0.00	0.00	0.15	0.00	0.00
Baghouse	%	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
FGD	%	1.25	0.82	0.45	1.25	0.82	0.38	1.25	0.82	0.38
Transformer Losses	%	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Miscellaneous	.	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

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TOTAL Auxiliary Power	%	10.21	11.04	9.26	10.16	10.98	9.14	7.95	8.81	6.94
Net Unit Heat Rate	Btu/kWh	9,349	9,963	9,423	9,302	9,912	9,369	9,291	9,901	9,360
Plant Efficiency	%	36.5	34.2	36.2	36.7	34.4	36.4	36.7	34.5	36.5
ECONOMIC ANALYSIS INPUT:										
2008 to COD	years	5	5	5	5	5	5	5	5	5
Start of Engineering to COD	months	55	55	55	55	55	55	55	55	55
Operating Life	years	35	35	35	35	35	35	35	35	35
Fixed Labor Costs	$	7,187,292	7,187,292	7,187,292	8,556,300	8,556,300	8,556,300	10,609,812	10,609,812	10,609,812
Fixed Non-Labor O&M Costs	$	5,280,000	5,280,000	5,280,000	6,660,000	6,660,000	6,660,000	8,460,000	8,460,000	8,460,000
Total Fixed O&M Costs	$	12,467,292	12,467,292	12,467,292	15,216,300	15,216,300	15,216,300	19,069,812	19,069,812	19,069,812
Fixed O&M Costs	$/net kW-yr	34.71	35.04	34.35	28.23	28.49	27.91	23.02	23.23	22.77
Property Taxes	$/year	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
		13.20			11.10			9.40	9.40	9.40
FGD Reagent Cost										
$/ton, delivered		15.00	15.00	95.00	15.00	15.00	95.00	15.00	15.00	95.00
Activated Carbon										
$/ton, delivered		2200	2200	2200	2200	2200	2200	2200	2200	2200
SCR Catalyst										
$/M^3		6000	6000	6000	6000	6000	6000	6000	6000	6000
Ammonia (Anhydrous)										
$/ton, delivered		450	450	450	450	450	450	450	450	450
Water Cost										
$/1000 gallons		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Fly Ash Sales	$/ton	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fly Ash Disposal	$/ton	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Bottom Ash Sales	$/ton	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Bottom Ash Disposal	$/ton	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Activated Carbon waste	$/ton	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
FGD Waste Sale	$/ton	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FGD Waste Disposal	$/ton	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Other Variable O&M Costs	$/net-MWh	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
SO2 Allowance Market Cost										
$/ton		$500	$500	$500	$500	$500	$500	$500	$500	$500
NOX Allowance Market Cost										
$/ton		$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000
Sulfur Byproduct										
$/ton		$0	$0	$0	$0	$0	$0	$0	$0	$0
Equivalent Availability Factor	%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
Replacement Power cost	$/gross-kWh	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Fuel Cost Delivered	$/mmBtu	1.70	1.50	1.40	1.70	1.50	1.40	1.70	1.50	1.40
$/ton, delivered		39.55	17.90	23.47	39.55	17.90	23.47	39.55	17.90	23.47
ECONOMIC ANALYSIS OUTPUT:										
Annual Capacity Factor	%/yr	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
Equivalent Full Load Hours	Hr's	7,880	7,880	7,880	7,880	7,880	7,880	7,880	7,880	7,880
Used for Potential to Emit (MW-hours@100%CF & Availability)	Mw-Hr/yr	2,830,113	2,804,040	2,860,107	4,247,782	4,208,964	4,295,800	6,528,050	6,467,510	6,600,072

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Capital costs	$1,000									
Direct & Indirect Costs $1000	$1,000	1,624,527	1,693,870	1,519,360	2,071,959	2,160,403	1,937,827	2,642,629	2,755,430	2,471,549
$/kW Capital Cost based on net output	$/net-kw	4,523	4,760	4,186	3,844	4,045	3,555	3,190	3,357	2,951
Capital Costs										
Costs in year 2008 dollars	$1,000	1,624,527	1,693,870	1,519,360	2,071,959	2,160,403	1,937,827	2,642,629	2,755,430	2,471,549
Fixed O&M Costs										
Fixed O&M Costs	$1,000	12,467	12,467	12,467	15,216	15,216	15,216	19,070	19,070	19,070
Variable O&M Costs ($/yr)										
Limestone Reagent	$1,000	1,504	781	0	2,246	1,167	0	3,447	1,791	0
Lime Reagent for Dry-FGD	$1,000	0	0	719	0	0	1,074	0	0	1,648
Activated Carbon	$1,000	0	1,073	976	0	1,602	1,457	0	2,459	2,237
Water	$1,000	238	295	191	385	385	385	579	579	579
Bottom Ash Disposal/Sale	$1,000	442	1,679	290	659	2,507	432	1,012	3,848	664
Fly ash sale/Disposal	$1,000	1,762	6,710	1,154	2,632	10,021	1,724	4,039	15,381	2,645
Gypsum sale/Disposal	$1,000	3,094	1,614	305	4,621	2,411	565	7,093	3,700	867
AC Waste Disposal	$1,000	0	10	9	0	15	13	0	22	20
Ammonia	$1,000	469	373	360	527	557	537	810	855	825
SCR-Catalyst Replacement	$1,000	673	673	673	1,010	1,010	1,010	1,515	1,515	1,515
Bags for Baghouse	$1,000	210	242	231	336	380	346	516	583	531
SO2 Allowances	$1,000	662	559	539	988	835	805	1,517	1,281	1,236
NOx Allowances	$1,000	1,985	2,096	2,022	2,965	3,131	3,020	4,551	4,805	4,636
Other	$1,000	1,416	1,403	1,431	2,125	2,106	2,149	3,266	3,235	3,302
Sulfur Sale	$1,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	$1,000	11,550	17,507	8,900	18,495	26,125	13,517	28,345	40,056	20,705
Variable O&M Costs	$/MWh	3.55	5.96	3.11	3.82	5.93	3.15	3.81	5.91	3.14
Total Non-Fuel O&M Cost	$1,000	24,017	29,974	21,367	33,711	41,341	28,733	47,415	59,126	39,775
Total Non-Fuel O&M Cost	$/MWh	8.48	10.68	7.47	7.93	9.82	6.69	7.26	9.14	6.02

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Number of BFW Heaters		**8 (HARP)**	**8 (HARP)**	**8 (HARP)**	**8 (HARP)**	**8 (HARP)**	**8 (HARP)**	**8 (HARP)**	**8 (HARP)**	**8 (HARP)**
Number of FGD Absorbers		**1**	**1**	**1**	**1**	**1**	**2**	**1**	**1**	**3**
Number of wet ESPs		**1**	**0**	**0**	**2**	**0**	**0**	**3**	**0**	**0**
Number of Pulverizers		**5**	**6**	**5**	**6**	**7**	**6**	**7**	**8**	**7**
SO2		**Wet FGD**	**Wet FGD**	**Dry FGD**	**Wet FGD**	**Wet FGD**	**Dry FGD**	**Wet FGD**	**Wet FGD**	**Dry FGD**
NOX		**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**
Primary Particulate Control		**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**
Secondary Particulate Control		**Wet ESP**	**None**	**None**	**Wet ESP**	**None**	**None**	**Wet ESP**	**None**	**None**
Mercury Control		**Inherent**	**ACI-w/BGH**	**ACI-w/BGH**	**Inherent**	**ACI-w/BGH**	**ACI-w/BGH**	**Inherent**	**ACI-w/BGH**	**ACI-w/BGH**
PLANT CONFIGURATION: (Gross-MW)		**1x400**	**1x400**	**1x400**	**1x600**	**1x600**	**1x600**	**1x900**	**1x900**	**1x900**
NO. OF STEAM GENERATORS		1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler
Main Steam Pressure	psig	3690	3690	3690	3690	3690	3690	3690	3690	3690
Main Steam Temperature	°F	1050	1050	1050	1050	1050	1050	1050	1050	1050
Hot Reheat Temperature	°F	1100	1100	1100	1100	1100	1100	1100	1100	1100
NO. OF STEAM TURBINES		1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine
SOx CONTROL:		Wet FGD	Wet FGD	Dry FGD	Wet FGD	Wet FGD	Dry FGD	Wet FGD	Wet FGD	Dry FGD
Uncontrolled SO2 Emission Rate	lb/mmBtu	4.32	2.14	0.52	4.32	2.14	0.52	4.32	2.14	0.52
Target "Permit" SO_2 Emission Rate	lb/mmBtu	0.10	0.08	0.08	0.10	0.08	0.08	0.10	0.08	0.08
SULFUR REMOVAL percent required meet Target "Permit" Rate	%	97.68	96.27	84.76	97.68	96.27	84.76	97.68	96.27	84.76
Typical Maximum SO2 Removal Guarantee from Vendor	%	98.15	97.20	84.76	98.15	97.20	84.76	98.15	97.20	84.76
NOx CONTROL:		SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR
Uncontrolled Rate from Furnace	lb/mmBtu	0.25	0.20	0.20	0.25	0.20	0.20	0.25	0.20	0.20
Target "Permit" NOx Emission Rate	lb/mmBtu	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
PARTICULATE CONTROL		Baghouse	Baghouse	Baghouse	Baghouse	Baghouse	Baghouse	Baghouse	Baghouse	Baghouse
Target "Permit" Emission Rate	lb/mmBtu	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Mercury Control		Inherent	ACI-w/BGH	ACI-w/BGH	Inherent	ACI-w/BGH	ACI-w/BGH	Inherent	ACI-w/BGH	ACI-w/BGH
Cooling Method		MD-CT	MD-CT	MD-CT	MD-CT	MD-CT	MD-CT	MD-CT	MD-CT	MD-CT
PLANT PERFORMANCE:										
Net Plant Heat Rate, HHV	Btu/net-kWh	9,058	9,647	9,128	9,017	9,603	9,080	8,990	9,576	9,057
Gross Plant Output	**Gross-kW**	**400,001**	**400,001**	**400,001**	**600,002**	**600,002**	**600,002**	**900,004**	**900,004**	**900,004**
Net Plant Output (based on Annual Average Conditions)	Net-kW	355,105	352,033	358,912	532,967	528,392	539,062	829,725	822,441	838,866
Gross Plant Heat Rate, HHV	Btu/gross-kWh	8,041	8,490	8,191	8,009	8,456	8,158	8,288	8,751	8,442
Auxiliary Power	kW	44,896	47,968	41,089	67,035	71,610	60,940	70,279	77,563	61,138
Turbine Heat Rate	Btu/kWh	7,038	7,038	7,038	7,011	7,011	7,011	7,256	7,256	7,256
Primary Fuel Feed Rate per Boiler	lb/hr	276,536	569,063	390,871	413,162	850,208	583,983	641,330	1,319,728	906,487
Primary Fuel Feed Rate per Boiler	Tons/hr	138	285	195	207	425	292	321	660	453
Primary Fuel Feed Rate per Boiler	lb/net-MWh	779	1,617	1,089	775	1,609	1,083	773	1,605	1,081
Full load Heat input to Boiler	mmBtu's/hr	3,216	3,396	3,276	4,806	5,074	4,895	7,459	7,876	7,598
Secondary Fuel Feed Rate	lb/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Secondary Fuel Feed Rate	lb/net-MWh	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lime/Limestone Feed Rate	lb/hr	24,364	12,661	1,839	36,401	18,916	2,748	56,503	29,362	4,266
Lime/Limestone Feed Rate	lb/net-MWh	68.6	36.0	5.1	68.3	35.8	5.1	68.1	35.7	5.1
Ammonia Feed Rate(Anhydrous)	lb/hr	253	201	194	285	301	290	442	467	451
Ammonia Feed Rate	lb/net-MWh	0.713	0.572	0.541	0.535	0.569	0.538	0.533	0.568	0.537
Activated Carbon Injection Rate	lb/hr	0	118	108	0	177	161	0	275	250
Activated Carbon Injection Rate	lb/net-MWh	0.00	0.34	0.30	0.00	0.34	0.30	0.00	0.33	0.30

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Water Consumption										
Cycle Make-up & Misc. Services	gpm	504	624	404	816	816	816	1228	1228	1228
Cooling Tower/lake make-up	gpm	4,261	4,224	4,307	6,396	6,341	6,469	9,957	9,869	10,066
Total Water	gpm	4,765	4,849	4,711	7,211	7,156	7,284	11,184	11,097	11,294
Water Consumption	gal/net-MWh	805	826	788	812	813	811	809	810	808
FUEL ANALYSIS:		Bituminous	Lignite	PRB	Bituminous	Lignite	PRB	Bituminous	Lignite	PRB
Ultimate Analysis										
Carbon	%	63.75	36.27	50.25	63.75	36.27	50.25	63.75	36.27	50.25
Sulfur	**%**	**2.51**	**0.64**	**0.22**	**2.51**	**0.64**	**0.22**	**2.51**	**0.64**	**0.22**
Oxygen	%	6.88	10.76	13.55	6.88	10.76	13.55	6.88	10.76	13.55
Hydrogen	%	4.50	2.42	3.41	4.50	2.42	3.41	4.50	2.42	3.41
Nitrogen	%	1.25	0.71	0.65	1.25	0.71	0.65	1.25	0.71	0.65
Chlorine	%	0.29	0.00	0.00	0.29	0.00	0.00	0.29	0.00	0.00
Ash	%	9.70	17.92	4.50	9.70	17.92	4.50	9.70	17.92	4.50
Moisture	%	11.12	31.24	27.40	11.12	31.24	27.40	11.12	31.24	27.40
Gross Higher Heating Value (Dulong)	Btu/lb	11,631	5,968	8,382	11,631	5,968	8,382	11,631	5,968	8,382
Hardgrove Grindability	HGI	59	59	59	59	59	59	59	59	59
SORBENT ANALYSIS:										
CaCO3	%	90	90	0	90	90	0	90	90	0
MgCO3	%	5	5	0	5	5	0	5	5	0
CaO	%	0	0	90	0	0	90	0	0	90
Ash/Inerts	%	5	5	10	5	5	10	5	5	10
Moisture	%	0	0	0	0	0	0	0	0	0
STEAM GENERATOR DATA (Per Boiler):										
Theoretical Air	lb/lb-fuel	8.70	4.57	6.39	8.70	4.57	6.39	8.70	4.57	6.39
Theoretical Dry Gas	lb/lb-fuel	9.09	4.87	6.76	9.09	4.87	6.76	9.09	4.87	6.76
Actual Dry Gas	lb/lb-fuel	10.83	5.78	8.04	10.83	5.78	8.04	10.83	5.78	8.04
Excess Air	%	20	20	20	20	20	20	20	20	20
Total Dry Air Flow	lb/lb-fuel	10.45	5.49	7.67	10.45	5.49	7.67	10.45	5.49	7.67
Ambient Air Moisture	lb/lb-lair	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025
Total Air Flow	lb/lb-fuel	10.71	5.63	7.86	10.71	5.63	7.86	10.71	5.63	7.86
Flue Gas Moisture Flow	lb/lb-fuel	0.774	0.666	0.770	0.774	0.666	0.770	0.774	0.666	0.770
Products of Combustion	lb/lb-fuel	11.61	6.45	8.81	11.61	6.45	8.81	11.61	6.45	8.81
Air Heater Leakage	%	5	5	5	5	5	5	5	5	5
Air Heater Inlet Temperature	°F	100	100	100	100	100	100	100	100	100
Infiltration	%	5	5	5	5	5	5	5	5	5
Exit Flue Gas Temperature	°F	310	305	280	310	305	280	310	305	280
Flue Gas Temp. Uncorrected	°F	319	314	288	319	314	288	319	314	288
Flue Gas Flow Rate (per boiler)	lb/hr	3,481,102	3,962,390	3,725,675	5,200,978	5,920,011	5,566,373	8,073,221	9,189,284	8,640,387
Flue Gas Flow Rate	acfm	1,164,200	1,316,554	1,197,448	1,739,385	1,966,998	1,789,057	2,699,962	3,053,256	2,777,058
Combustion Air Flow	lb/hr	2,960,711	3,201,971	3,070,938	4,423,482	4,783,907	4,588,158	6,866,352	7,425,777	7,121,955
Combustion Air Flow	acfm	706,252	763,802	732,545	1,055,183	1,141,159	1,094,465	1,637,908	1,771,354	1,698,880
Stack Flue Gas Temperature	°F	135	140	170	135	140	170	135	140	170
Stack Flue Gas Flow Rate per Flue	acfm	952,604	1,093,420	1,100,264	1,423,248	1,633,625	1,643,857	2,209,238	2,535,780	2,551,673
Radiation Loss	%	0.196	0.196	0.196	0.185	0.185	0.185	0.175	0.175	0.175
Dry Gas Heat Loss	%	5.89	5.96	5.19	5.89	5.96	5.19	5.89	5.96	5.19
Fuel Moisture Loss	%	1.07	5.84	3.62	1.07	5.84	3.62	1.07	5.84	3.62
Hydrogen in Fuel Loss	%	3.89	4.07	4.06	3.89	4.07	4.06	3.89	4.07	4.06
Air Moisture Heat Loss	%	0.237	0.236	0.206	0.237	0.236	0.206	0.237	0.236	0.206
Carbon Loss	%	0.50	0.10	0.10	0.50	0.10	0.10	0.50	0.10	0.10
Unaccounted Loss	%	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Manufacturer's Margin	%	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50

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		Supercritical	Supercritical	Supercritical	Supercritical	Supercritical	Supercritical	Supercritical	Supercritical	Supercritical
Base set-up for meeting Target BACT limits for NOX & SO2	**UNITS**	**400MW - Supercritical PC, Bituminous**	**400MW - Supercritical PC, Lignite**	**400MW - Supercritical PC, PRB**	**600MW - Supercritical PC, Bituminous**	**600MW - Supercritical PC, Lignite**	**600MW - Supercritical PC, PRB**	**900MW - Supercritical PC, Bituminous**	**900MW - Supercritical PC, Lignite**	**900MW - Supercritical PC, PRB**
Total Boiler Loss	%	12.48	17.10	14.07	12.46	17.09	14.06	12.45	17.08	14.05
Boiler Efficiency	%	87.52	82.90	85.93	87.54	82.91	85.94	87.55	82.92	85.95
Total Heat Output from Boiler	mmBtu/hr	2,815.21	2,815.21	2,815.21	4,206.61	4,206.61	4,206.61	6,530.43	6,530.43	6,530.43
Main Steam Flow	lb/hr	2,503,200	2,503,200	2,503,200	3,727,700	3,727,700	3,727,700	5,758,900	5,758,900	5,758,900
STEAM TURBINE/CYCLE DATA (Per Turbine):										
Turbine Back Pressure	in HgA	2	2	2	2	2	2	2	2	2
Steam Turbine Gross Output	kW	400,001	400,001	400,001	600,002	600,002	600,002	900,004	900,004	900,004
LP Turbine Exhaust to Condenser	lb/hr	1,547,948	1,547,948	1,547,948	2,305,964	2,305,964	2,305,964	3,248,365	3,248,365	3,248,365
Exhaust Energy	Btu/lb	1,015.40	1,015.40	1,015.40	1,015.80	1,015.80	1,015.80	1,015.50	1,015.50	1,015.50
Condensate Enthalpy	Btu/lb	69.1	69.1	69.1	69.1	69.1	69.1	69.1	69.1	69.1
Heat Rejection from LP Turbine	mmBtu/hr	1,465	1,465	1,465	2,183	2,183	2,183	3,074	3,074	3,074
BFP Turbine Drive Steam Flow	lb/hr	0	0	0	0	0	0	329,912	329,912	329,912
BFP Turbine Exhaust Enthalpy	Btu/lb	0	0	0	0	0	0	1,053	1,053	1,053
Heat Rejection from BFP Turbine	Btu/hr	0	0	0	0	0	0	312	312	312
Total Heat Rejected to Condenser	mmBtu/hr	1,465	1,465	1,465	2,183	2,183	2,183	3,386	3,386	3,386
Circulating Water Temp. Rise	°F	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Circulating Water Flow	gpm	155,068	155,068	155,068	230,896	230,896	230,896	358,743	358,743	358,743
Number of Cooling Tower Cells		14	14	14	20	20	20	30	30	30
Total Circ. Water Flow	gpm	155,068	155,068	155,068	230,896	230,896	230,896	358,743	358,743	358,743
Service Water Flow	gpm	7,753	7,753	7,753	11,545	11,545	11,545	17,937	17,937	17,937
Total Cooling Water Requirement	gpm	162,821	162,821	162,821	242,441	242,441	242,441	376,680	376,680	376,680
PLANT AUXILIARY POWER:										
Induced Draft Fan Pressure Rise	"wc	44.0	44.0	41.8	44.0	44.0	41.8	44.0	44.0	41.8
Boiler	"w.c	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Econ Outlet to SCR outlet	"w.c	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
SCR Outlet to AH Outlet	"w.c	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
AH Outlet to ESP Outlet	"w.c	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AH/ESP Outlet to COHPAC or Dry FGD/BH Outlet	"w.c	8.0	8.0	16.0	8.0	8.0	16.0	8.0	8.0	16.0
COHPAC/Dry FGD BH Outlet to stack	"w.c	0.0	0.0	2.0	0.0	0.0	2.0	0.0	0.0	2.0
ID inlet to Wet FGD outlet	"w.c	8.0	8.0	0.0	8.0	8.0	0.0	8.0	8.0	0.0
Wet FGD outlet to stack outlet	"w.c	4.0	4.0	0.0	4.0	4.0	0.0	4.0	4.0	0.0
Total ID fan static pressure	"w.c	40.0	40.0	38.0	40.0	40.0	38.0	40.0	40.0	38.0
Percent Total Air to FD Fan	%	70	70	70	70	70	70	70	70	70
Forced Draft Fan Pressure Rise	"wc	20	20	20	20	20	20	20	20	20
Percent Total Air to PA Fan	%	30	30	30	30	30	30	30	30	30
Primary Air Fan Pressure Rise	"wc	40	40	40	40	40	40	40	40	40
Percent Total Air to SA Fan	%	0	0	0	0	0	0	0	0	0
Secondary Air Fan Pressure Rise	"wc	15	15	15	15	15	15	15	15	15
Condensate P/P	%	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
Circulating Water P/P	%	0.47	0.47	0.47	0.46	0.46	0.46	0.48	0.48	0.48
Cooling Towers	%	0.72	0.72	0.72	0.69	0.69	0.69	0.69	0.69	0.69
Feedwater P/P	%	3.50	3.50	3.50	3.50	3.50	3.50	0.00	0.00	0.00
Subtotal CWS	%	5.05	5.05	5.05	5.01	5.01	5.01	1.53	1.53	1.53
Forced Draft Fan	%	0.34	0.37	0.36	0.34	0.37	0.36	0.36	0.38	0.37
Induced Draft Fan	%	2.00	2.26	1.79	1.99	2.25	1.78	2.06	2.33	1.84
Primary Air Fan	%	0.30	0.32	0.31	0.30	0.32	0.31	0.31	0.33	0.32
Pulverizer	%	0.50	1.02	0.70	0.50	1.02	0.70	0.51	1.06	0.73
Fuel Handling	%	0.12	0.22	0.16	0.12	0.22	0.16	0.12	0.23	0.16
Ash Handling	%	0.19	0.60	0.14	0.19	0.60	0.14	0.19	0.62	0.14
Wet ESP for H2SO4 collection	%	0.15	0.00	0.00	0.15	0.00	0.00	0.15	0.00	0.00
Baghouse	%	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
FGD	%	1.25	0.82	0.45	1.25	0.82	0.38	1.25	0.82	0.38
Transformer Losses	%	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Miscellaneous	.	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

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TOTAL Auxiliary Power	%	11.22	11.99	10.27	11.17	11.93	10.16	7.81	8.62	6.79
Net Unit Heat Rate	Btu/kWh	9,058	9,647	9,128	9,017	9,603	9,080	8,990	9,576	9,057
Plant Efficiency	%	37.7	35.4	37.4	37.8	35.5	37.6	38.0	35.6	37.7
ECONOMIC ANALYSIS INPUT:										
2008 to COD	years	5	5	5	5	5	5	5	5	5
Start of Engineering to COD	months	55	55	55	55	55	55	55	55	55
Operating Life	years	35	35	35	35	35	35	35	35	35
Fixed Labor Costs	$	7,187,292	7,187,292	7,187,292	8,556,300	8,556,300	8,556,300	10,609,812	10,609,812	10,609,812
Fixed Non-Labor O&M Costs	$	5,600,014	5,600,014	5,600,014	7,020,023	7,020,023	7,020,023	8,820,039	8,820,039	8,820,039
Total Fixed O&M Costs	$	12,787,306	12,787,306	12,787,306	15,576,323	15,576,323	15,576,323	19,429,851	19,429,851	19,429,851
Fixed O&M Costs	$/net kW-yr	36.01	36.32	35.63	29.23	29.48	28.90	23.42	23.62	23.16
Property Taxes	$/year	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
FGD Reagent Cost										
$/ton, delivered		15.00	15.00	95.00	15.00	15.00	95.00	15.00	15.00	95.00
Activated Carbon										
$/ton, delivered		2200	2200	2200	2200	2200	2200	2200	2200	2200
SCR Catalyst										
$/M^3		6000	6000	6000	6000	6000	6000	6000	6000	6000
Ammonia (Anhydrous)										
$/ton, delivered		450	450	450	450	450	450	450	450	450
Water Cost										
$/1000 gallons		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Fly Ash Sales	$/ton	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fly Ash Disposal	$/ton	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Bottom Ash Sales	$/ton	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Bottom Ash Disposal	$/ton	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Activated Carbon waste	$/ton	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
FGD Waste Sale	$/ton	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FGD Waste Disposal	$/ton	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Other Variable O&M Costs	$/net-MWh	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
SO2 Allowance Market Cost										
$/ton		$500	$500	$500	$500	$500	$500	$500	$500	$500
NOX Allowance Market Cost										
$/ton		$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000
Sulfur Byproduct										
$/ton		$0	$0	$0	$0	$0	$0	$0	$0	$0
Equivalent Availability Factor	%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
Replacement Power cost	$/gross-kWh	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Fuel Cost Delivered	$/mmBtu	1.70	1.50	1.40	1.70	1.50	1.40	1.70	1.50	1.40
$/ton, delivered		39.55	17.90	23.47	39.55	17.90	23.47	39.55	17.90	23.47
ECONOMIC ANALYSIS OUTPUT:										
Annual Capacity Factor	%/yr	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
Equivalent Full Load Hours	Hr's	7,880	7,880	7,880	7,880	7,880	7,880	7,880	7,880	7,880
Used for Potential to Emit (MW-hours@100%CF & Availability)	Mw-Hr/yr	2,798,226	2,774,021	2,828,225	4,199,782	4,163,729	4,247,807	6,538,232	6,480,833	6,610,262

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Capital costs	$1,000									
Direct & Indirect Costs $1000	$1,000	1,663,873	1,735,779	1,554,896	2,122,143	2,213,853	1,983,150	2,706,635	2,823,605	2,529,357
$/kW Capital Cost based on net summer output	$/net-kw	4,686	4,931	4,332	3,982	4,190	3,679	3,262	3,433	3,015
Capital Costs										
Costs in year 2008 dollars	$1,000	1,663,873	1,735,779	1,554,896	2,122,143	2,213,853	1,983,150	2,706,635	2,823,605	2,529,357
Fixed O&M Costs										
Fixed O&M Costs	$1,000	12,787	12,787	12,787	15,576	15,576	15,576	19,430	19,430	19,430
Variable O&M Costs ($/yr)										
Limestone Reagent	$1,000	1,441	749	0	2,152	1,118	0	3,341	1,736	0
Lime Reagent for Dry-FGD	$1,000	0	0	689	0	0	1,029	0	0	1,597
Activated Carbon	$1,000	0	1,028	935	0	1,535	1,396	0	2,383	2,168
Water	$1,000	238	295	191	386	386	386	581	581	581
Bottom Ash Sale/Disposal	$1,000	423	1,608	277	632	2,402	414	981	3,729	643
Fly ash sale/Disposal	$1,000	1,688	6,428	1,106	2,522	9,603	1,652	3,915	14,907	2,564
Gypsum sale/Disposal	$1,000	2,964	1,546	292	4,429	2,310	541	6,874	3,586	840
AC Waste Disposal	$1,000	0	9	8	0	14	13	0	22	20
Ammonia	$1,000	449	357	345	505	534	515	785	828	799
SCR-Catalyst Replacement	$1,000	673	673	673	1,010	1,010	1,010	1,515	1,515	1,515
Bags for Baghouse	$1,000	202	231	222	322	364	331	500	565	514
SO2 Allowances	$1,000	634	535	517	947	800	772	1,470	1,242	1,198
NOx Allowances	$1,000	1,902	2,008	1,937	2,842	3,000	2,894	4,411	4,657	4,493
Other	$1,000	1,400	1,388	1,415	2,101	2,083	2,125	3,271	3,242	3,307
Sulfur Sale	$1,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	$1,000	11,147	16,856	8,607	17,848	25,160	13,078	27,643	38,993	20,239
Variable O&M Costs	$/MWh	3.98	6.07	3.04	3.74	5.77	3.08	3.72	5.75	3.06
Total Non-Fuel O&M Cost	$1,000	23,934	29,643	21,394	33,424	40,736	28,654	47,073	58,423	39,669
Total Non-Fuel O&M Cost	$/MWh	8.55	10.68	7.56	7.95	9.78	6.74	7.20	9.01	6.00

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Ultra-Supercritical

		Ultra-Supercritical	Ultra-Supercritical	Ultra-Supercritical	Ultra-Supercritical	Ultra-Supercritical	Ultra-Supercritical	Ultra-Supercritical	Ultra-Supercritical	Ultra-Supercritical
Base set-up for meeting Target BACT limits for NOX & SO2	**UNITS**	**400MW - Ultra-Supercritical PC, Bituminous**	**400MW - Ultra-Supercritical PC, Lignite**	**400MW - Ultra-Supercritical PC, PRB**	**600MW - Ultra-Supercritical PC, Bituminous**	**600MW - Ultra-Supercritical PC, Lignite**	**600MW - Ultra-Supercritical PC, PRB**	**900MW - Ultra-Supercritical PC, Bituminous**	**900MW - Ultra-Supercritical PC, Lignite**	**900MW - Ultra-Supercritical PC, PRB**
Number of BFW Heaters		**8 Heaters (HARP)**	**8 (HARP)**	**8 (HARP)**	**8 (HARP)**	**8 (HARP)**	**8 (HARP)**	**8 (HARP)**	**8 (HARP)**	**8 (HARP)**
Number of FGD Absorbers		**1**	**1**	**1**	**1**	**1**	**2**	**1**	**1**	**3**
Number of wet ESPs		**1**	**0**	**0**	**2**	**0**	**0**	**3**	**0**	**0**
Number of Pulverizers		**5**	**6**	**5**	**6**	**7**	**6**	**7**	**8**	**7**
SO2		**Wet FGD**	**Wet FGD**	**Dry FGD**	**Wet FGD**	**Wet FGD**	**Dry FGD**	**Wet FGD**	**Wet FGD**	**Dry FGD**
NOX		**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**
Primary Particulate Control		**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**
Secondary Particulate Control		**Wet ESP**	**None**	**None**	**Wet ESP**	**None**	**None**	**Wet ESP**	**None**	**None**
Mercury Control		**Inherent**	**ACI-w/BGH**	**ACI-w/BGH**	**Inherent**	**ACI-w/BGH**	**ACI-w/BGH**	**Inherent**	**ACI-w/BGH**	**ACI-w/BGH**
PLANT CONFIGURATION: (Gross-MW)		**1x400**	**1x400**	**1x400**	**1x600**	**1x600**	**1x600**	**1x900**	**1x900**	**1x900**
NO. OF STEAM GENERATORS		1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler
Main Steam Pressure	psig	3748	3748	3748	3748	3748	3748	3748	3748	3748
Main Steam Temperature	°F	1100	1100	1100	1100	1100	1100	1100	1100	1100
Hot Reheat Temperature	°F	1100	1100	1100	1100	1100	1100	1100	1100	1100
NO. OF STEAM TURBINES		1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine
SOx CONTROL:		Wet FGD	Wet FGD	Dry FGD	Wet FGD	Wet FGD	Dry FGD	Wet FGD	Wet FGD	Dry FGD
Uncontrolled SO2 Emission Rate	lb/mmBtu	4.32	2.14	0.52	4.32	2.14	0.52	4.32	2.14	0.52
Target "Permit" SO_2 Emission Rate	lb/mmBtu	0.10	0.08	0.08	0.10	0.08	0.08	0.10	0.08	0.08
SULFUR REMOVAL percent required meet Target "Permit" Rate	%	97.68	96.27	84.76	97.68	96.27	84.76	97.68	96.27	84.76
Typical Maximum SO2 Removal Guarantee from Vendor	%	98.15	97.20	84.76	98.15	97.20	84.76	98.15	97.20	84.76
NOx CONTROL:		SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR
Uncontrolled Rate from Furnace	lb/mmBtu	0.25	0.20	0.20	0.25	0.20	0.20	0.25	0.20	0.20
Target "Permit" NOx Emission Rate	lb/mmBtu	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
PARTICULATE CONTROL		Baghouse	Baghouse	Baghouse	Baghouse	Baghouse	Baghouse	Baghouse	Baghouse	Baghouse
Target "Permit" Emission Rate	lb/mmBtu	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Specified Design Guarantee from vendor	lb/mmBtu	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
Mercury Control		Inherent	ACI-w/BGH	ACI-w/BGH	Inherent	ACI-w/BGH	ACI-w/BGH	Inherent	ACI-w/BGH	ACI-w/BGH
Cooling Method		MD-CT	MD-CT	MD-CT	MD-CT	MD-CT	MD-CT	MD-CT	MD-CT	MD-CT
PLANT PERFORMANCE:										
Net Plant Heat Rate, HHV	Btu/net-kWh	8,924	9,502	8,993	8,874	9,449	8,937	8,855	9,430	8,921
Gross Plant Output	**Gross-kW**	**400,004**	**400,004**	**400,004**	**600,001**	**600,001**	**600,001**	**900,001**	**900,001**	**900,001**
Net Plant Output (based on Annual Average Conditions)	Net-kW	354,969	351,979	358,776	532,781	528,336	538,876	830,306	823,201	839,447
Gross Plant Heat Rate, HHV	Btu/gross-kWh	7,919	8,361	8,066	7,880	8,320	8,027	8,170	8,626	8,321
Auxiliary Power	kW	45,035	48,025	41,228	67,220	71,665	61,125	69,695	76,800	60,554
Turbine Heat Rate	Btu/kWh	6,931	6,931	6,931	6,898	6,898	6,898	7,152	7,152	7,152
Primary Fuel Feed Rate per Boiler	lb/hr	272,335	560,418	384,933	406,504	836,508	574,573	632,138	1,300,812	893,494
Primary Fuel Feed Rate per Boiler	Tons/hr	136	280	192	203	418	287	316	650	447
Primary Fuel Feed Rate per Boiler	lb/net-MWh	767	1,592	1,073	763	1,583	1,066	761	1,580	1,064
Full load Heat input to Boiler	mmBtu's/hr	3,168	3,344	3,226	4,728	4,992	4,816	7,353	7,763	7,489
Secondary Fuel Feed Rate	lb/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Secondary Fuel Feed Rate	lb/net-MWh	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lime/Limestone Feed Rate	lb/hr	23,994	12,469	1,811	35,814	18,611	2,704	55,694	28,941	4,204
Lime/Limestone Feed Rate	lb/net-MWh	67.6	35.4	5.0	67.2	35.2	5.0	67.1	35.2	5.0
Ammonia Feed Rate(Anhydrous)	lb/hr	249	198	191	280	296	286	436	460	444
Ammonia Feed Rate	lb/net-MWh	0.702	0.563	0.533	0.526	0.560	0.530	0.525	0.559	0.529
Activated Carbon Injection Rate	lb/hr	0	117	106	0	174	158	0	271	246
Activated Carbon Injection Rate	lb/net-MWh	0.00	0.33	0.30	0.00	0.33	0.29	0.00	0.33	0.29

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Base set-up for meeting Target BACT limits for NOX & SO2	**UNITS**	**400MW - Ultra-Supercritical PC, Bituminous**	**400MW - Ultra-Supercritical PC, Lignite**	**400MW - Ultra-Supercritical PC, PRB**	**600MW - Ultra-Supercritical PC, Bituminous**	**600MW - Ultra-Supercritical PC, Lignite**	**600MW - Ultra-Supercritical PC, PRB**	**900MW - Ultra-Supercritical PC, Bituminous**	**900MW - Ultra-Supercritical PC, Lignite**	**900MW - Ultra-Supercritical PC, PRB**
Water Consumption										
Cycle Make-up & Misc. Services	gpm	506	626	406	819	819	819	1225	1225	1225
Cooling Tower/lake make-up	gpm	4,260	4,224	4,305	6,393	6,340	6,467	9,964	9,878	10,073
Total Water	gpm	4,766	4,850	4,712	7,212	7,159	7,285	11,189	11,104	11,299
Water Consumption	gal/net-MWh	806	827	788	812	813	811	809	809	808
FUEL ANALYSIS:		Bituminous	Lignite	PRB	Bituminous	Lignite	PRB	Bituminous	Lignite	PRB
Ultimate Analysis										
Carbon	%	63.75	36.27	50.25	63.75	36.27	50.25	63.75	36.27	50.25
Sulfur	**%**	**2.51**	**0.64**	**0.22**	**2.51**	**0.64**	**0.22**	**2.51**	**0.64**	**0.22**
Oxygen	%	6.88	10.76	13.55	6.88	10.76	13.55	6.88	10.76	13.55
Hydrogen	%	4.50	2.42	3.41	4.50	2.42	3.41	4.50	2.42	3.41
Nitrogen	%	1.25	0.71	0.65	1.25	0.71	0.65	1.25	0.71	0.65
Chlorine	%	0.29	0.00	0.00	0.29	0.00	0.00	0.29	0.00	0.00
Ash	%	9.70	17.92	4.50	9.70	17.92	4.50	9.70	17.92	4.50
Moisture	%	11.12	31.24	27.40	11.12	31.24	27.40	11.12	31.24	27.40
Gross Higher Heating Value (Dulong)	Btu/lb	11,631	5,968	8,382	11,631	5,968	8,382	11,631	5,968	8,382
SORBENT ANALYSIS:										
CaCO3	%	90	90	0	90	90	0	90	90	0
MgCO3	%	5	5	0	5	5	0	5	5	0
CaO	%	0	0	90	0	0	90	0	0	90
Ash/Inerts	%	5	5	10	5	5	10	5	5	10
Moisture	%	0	0	0	0	0	0	0	0	0
STEAM GENERATOR DATA (Per Boiler):										
Theoretical Air	lb/lb-fuel	8.70	4.57	6.39	8.70	4.57	6.39	8.70	4.57	6.39
Theoretical Dry Gas	lb/lb-fuel	9.09	4.87	6.76	9.09	4.87	6.76	9.09	4.87	6.76
Actual Dry Gas	lb/lb-fuel	10.83	5.78	8.04	10.83	5.78	8.04	10.83	5.78	8.04
Excess Air	%	20	20	20	20	20	20	20	20	20
Total Dry Air Flow	lb/lb-fuel	10.45	5.49	7.67	10.45	5.49	7.67	10.45	5.49	7.67
Ambient Air Moisture	lb/lb-lair	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025
Total Air Flow	lb/lb-fuel	10.71	5.63	7.86	10.71	5.63	7.86	10.71	5.63	7.86
Flue Gas Moisture Flow	lb/lb-fuel	0.774	0.666	0.770	0.774	0.666	0.770	0.774	0.666	0.770
Products of Combustion	lb/lb-fuel	11.61	6.45	8.81	11.61	6.45	8.81	11.61	6.45	8.81
Air Heater Leakage	%	5	5	5	5	5	5	5	5	5
Air Heater Inlet Temperature	°F	100	100	100	100	100	100	100	100	100
Infiltration	%	5	5	5	5	5	5	5	5	5
Exit Flue Gas Temperature	°F	310	305	280	310	305	280	310	305	280
Flue Gas Temp. Uncorrected	°F	319	314	288	319	314	288	319	314	288
Flue Gas Flow Rate (per boiler)	lb/hr	3,428,222	3,902,200	3,669,080	5,117,166	5,824,613	5,476,673	7,957,506	9,057,574	8,516,544
Flue Gas Flow Rate	acfm	1,146,515	1,296,555	1,179,258	1,711,356	1,935,301	1,760,227	2,661,263	3,009,493	2,737,255
Combustion Air Flow	lb/hr	2,915,736	3,153,332	3,024,289	4,352,199	4,706,817	4,514,221	6,767,936	7,319,343	7,019,876
Combustion Air Flow	acfm	695,523	752,200	721,418	1,038,179	1,122,770	1,076,828	1,614,432	1,745,965	1,674,530
Stack Flue Gas Temperature	°F	135	140	170	135	140	170	135	140	170
Stack Flue Gas Flow Rate per Flue	acfm	938,133	1,076,811	1,083,550	1,400,313	1,607,300	1,617,367	2,177,573	2,499,435	2,515,100
Radiation Loss	%	0.196	0.196	0.196	0.185	0.185	0.185	0.176	0.176	0.176
Dry Gas Heat Loss	%	5.89	5.96	5.19	5.89	5.96	5.19	5.89	5.96	5.19
Fuel Moisture Loss	%	1.07	5.84	3.62	1.07	5.84	3.62	1.07	5.84	3.62
Hydrogen in Fuel Loss	%	3.89	4.07	4.06	3.89	4.07	4.06	3.89	4.07	4.06
Air Moisture Heat Loss	%	0.237	0.236	0.206	0.237	0.236	0.206	0.237	0.236	0.206
Carbon Loss	%	0.50	0.10	0.10	0.50	0.10	0.10	0.50	0.10	0.10
Unaccounted Loss	%	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Manufacturer's Margin	%	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50

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Base set-up for meeting Target BACT limits for NOX & SO2	**UNITS**	**400MW - Ultra-Supercritical PC, Bituminous**	**400MW - Ultra-Supercritical PC, Lignite**	**400MW - Ultra-Supercritical PC, PRB**	**600MW - Ultra-Supercritical PC, Bituminous**	**600MW - Ultra-Supercritical PC, Lignite**	**600MW - Ultra-Supercritical PC, PRB**	**900MW - Ultra-Supercritical PC, Bituminous**	**900MW - Ultra-Supercritical PC, Lignite**	**900MW - Ultra-Supercritical PC, PRB**
Total Boiler Loss	%	12.48	17.10	14.07	12.46	17.09	14.06	12.46	17.08	14.05
Boiler Efficiency	%	87.52	82.90	85.93	87.54	82.91	85.94	87.54	82.92	85.95
Total Heat Output from Boiler	mmBtu/hr	2,772.43	2,772.43	2,772.43	4,138.81	4,138.81	4,138.81	6,436.81	6,436.81	6,436.81
Main Steam Flow	lb/hr	2,587,480	2,587,480	2,587,480	3,848,020	3,848,020	3,848,020	5,666,050	5,666,050	5,666,050
STEAM TURBINE/CYCLE DATA (Per Turbine):										
Turbine Back Pressure	in HgA	2	2	2	2	2	2	2	2	2
Steam Turbine Gross Output	kW	400,004	400,004	400,004	600,001	600,001	600,001	900,001	900,001	900,001
LP Turbine Exhaust to Condenser	lb/hr	1,518,346	1,518,346	1,518,346	2,257,395	2,257,395	2,257,395	3,160,394	3,160,394	3,160,394
Exhaust Energy	Btu/lb	1,007.10	1,007.10	1,007.10	1,007.20	1,007.20	1,007.20	1,004.20	1,004.20	1,004.20
Condensate Enthalpy	Btu/lb	69.1	69.1	69.1	69.1	69.1	69.1	69.1	69.1	69.1
Heat Rejection from LP Turbine	mmBtu/hr	1,424	1,424	1,424	2,118	2,118	2,118	2,955	2,955	2,955
BFP Turbine Drive Steam Flow	lb/hr	0	0	0	0	0	0	359,749	359,749	359,749
BFP Turbine Exhaust Enthalpy	Btu/lb	0	0	0	0	0	0	1,040	1,040	1,040
Heat Rejection from BFP Turbine	Btu/hr	0	0	0	0	0	0	336	336	336
Total Heat Rejected to Condenser	mmBtu/hr	1,424	1,424	1,424	2,118	2,118	2,118	3,292	3,292	3,292
Circulating Water Temp. Rise	°F	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Circulating Water Flow	gpm	150,792	150,792	150,792	224,026	224,026	224,026	348,393	348,393	348,393
Number of Cooling Tower Cells		14	14	14	20	20	20	30	30	30
Total Circ. Water Flow	gpm	150,792	150,792	150,792	224,026	224,026	224,026	348,393	348,393	348,393
Service Water Flow	gpm	7,540	7,540	7,540	11,201	11,201	11,201	17,420	17,420	17,420
Total Cooling Water Requirement	gpm	158,332	158,332	158,332	235,227	235,227	235,227	365,813	365,813	365,813
PLANT AUXILIARY POWER:										
Induced Draft Fan Pressure Rise	"wc	44.0	44.0	41.8	44.0	44.0	41.8	44.0	44.0	41.8
Boiler	"w.c	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Econ Outlet to SCR outlet	"w.c	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
SCR Outlet to AH Outlet	"w.c	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
AH Outlet to ESP Outlet	"w.c	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AH/ESP Outlet to COHPAC or Dry FGD/BH Outlet	"w.c	8.0	8.0	16.0	8.0	8.0	16.0	8.0	8.0	16.0
COHPAC/Dry FGD BH Outlet to stack	"w.c	0.0	0.0	2.0	0.0	0.0	2.0	0.0	0.0	2.0
ID inlet to Wet FGD outlet	"w.c	8.0	8.0	0.0	8.0	8.0	0.0	8.0	8.0	0.0
Wet FGD outlet to stack outlet	"w.c	4.0	4.0	0.0	4.0	4.0	0.0	4.0	4.0	0.0
Total ID fan static pressure	"w.c	40.0	40.0	38.0	40.0	40.0	38.0	40.0	40.0	38.0
Percent Total Air to FD Fan	%	70	70	70	70	70	70	70	70	70
Forced Draft Fan Pressure Rise	"wc	20	20	20	20	20	20	20	20	20
Percent Total Air to PA Fan	%	30	30	30	30	30	30	30	30	30
Primary Air Fan Pressure Rise	"wc	40	40	40	40	40	40	40	40	40
Percent Total Air to SA Fan	%	0	0	0	0	0	0	0	0	0
Secondary Air Fan Pressure Rise	"wc	15	15	15	15	15	15	15	15	15
Condensate P/P	%	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
Circulating Water P/P	%	0.45	0.45	0.45	0.45	0.45	0.45	0.47	0.47	0.47
Cooling Towers	%	0.72	0.72	0.72	0.69	0.69	0.69	0.69	0.69	0.69
Feedwater P/P	%	3.60	3.60	3.60	3.60	3.60	3.60	0.00	0.00	0.00
Subtotal CWS	%	5.14	5.14	5.14	5.10	5.10	5.10	1.52	1.52	1.52
Forced Draft Fan	%	0.34	0.37	0.35	0.34	0.37	0.35	0.35	0.38	0.36
Induced Draft Fan	%	1.97	2.23	1.76	1.96	2.22	1.75	2.03	2.30	1.81
Primary Air Fan	%	0.29	0.32	0.31	0.29	0.32	0.30	0.30	0.33	0.31
Pulverizer	%	0.49	1.01	0.69	0.49	1.00	0.69	0.51	1.04	0.72
Fuel Handling	%	0.12	0.22	0.16	0.12	0.22	0.16	0.12	0.22	0.16
Ash Handling	%	0.19	0.59	0.14	0.18	0.59	0.14	0.19	0.61	0.14
Wet ESP for H2SO4 collection	%	0.15	0.00	0.00	0.15	0.00	0.00	0.15	0.00	0.00
Baghouse	%	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
FGD	%	1.25	0.82	0.45	1.25	0.82	0.38	1.25	0.82	0.38
Transformer Losses	%	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Miscellaneous	.	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

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Base set-up for meeting Target BACT limits for NOX & SO2	**UNITS**	**400MW - Ultra-Supercritical PC, Bituminous**	**400MW - Ultra-Supercritical PC, Lignite**	**400MW - Ultra-Supercritical PC, PRB**	**600MW - Ultra-Supercritical PC, Bituminous**	**600MW - Ultra-Supercritical PC, Lignite**	**600MW - Ultra-Supercritical PC, PRB**	**900MW - Ultra-Supercritical PC, Bituminous**	**900MW - Ultra-Supercritical PC, Lignite**	**900MW - Ultra-Supercritical PC, PRB**
TOTAL Auxiliary Power	%	11.26	12.01	10.31	11.20	11.94	10.19	7.74	8.53	6.73
Net Unit Heat Rate	Btu/kWh	8,924	9,502	8,993	8,874	9,449	8,937	8,855	9,430	8,921
Plant Efficiency	%	38.2	35.9	37.9	38.4	36.1	38.2	38.5	36.2	38.2
ECONOMIC ANALYSIS INPUT:										
2008 to COD	years	5	5	5	5	5	5	5	5	5
Start of Engineering to COD	months	55	55	55	55	55	55	55	55	55
Operating Life	years	35	35	35	35	35	35	35	35	35
Fixed Labor Costs	$	7,187,292	7,187,292	7,187,292	8,556,300	8,556,300	8,556,300	10,609,812	10,609,812	10,609,812
Fixed Non-Labor O&M Costs	$	5,760,058	5,760,058	5,760,058	7,200,012	7,200,012	7,200,012	9,000,010	9,000,010	9,000,010
Total Fixed O&M Costs	$	12,947,350	12,947,350	12,947,350	15,756,312	15,756,312	15,756,312	19,609,822	19,609,822	19,609,822
Fixed O&M Costs	$/net kW-yr	36.47	36.78	36.09	29.57	29.82	29.24	23.62	23.82	23.36
Property Taxes	$/year	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
FGD Reagent Cost										
$/ton, delivered		15.00	15.00	95.00	15.00	15.00	95.00	15.00	15.00	95.00
Activated Carbon										
$/ton, delivered		2200	2200	2200	2200	2200	2200	2200	2200	2200
SCR Catalyst										
$/M^3		6000	6000	6000	6000	6000	6000	6000	6000	6000
Ammonia (Anhydrous)										
$/ton, delivered		450	450	450	450	450	450	450	450	450
Water Cost										
$/1000 gallons		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Fly Ash Sales	$/ton	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fly Ash Disposal	$/ton	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Bottom Ash Sales	$/ton	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Bottom Ash Disposal	$/ton	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Activated Carbon waste	$/ton	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
FGD Waste Sale	$/ton	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FGD Waste Disposal	$/ton	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Other Variable O&M Costs	$/net-MWh	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
SO2 Allowance Market Cost										
$/ton		$500	$500	$500	$500	$500	$500	$500	$500	$500
NOX Allowance Market Cost										
$/ton		$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000
Sulfur Byproduct										
$/ton		$0	$0	$0	$0	$0	$0	$0	$0	$0
Equivalent Availability Factor	%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
Replacement Power cost	$/gross-kWh	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Fuel Cost Delivered	$/mmBtu	1.70	1.50	1.40	1.70	1.50	1.40	1.70	1.50	1.40
$/ton, delivered		39.55	17.90	23.47	39.55	17.90	23.47	39.55	17.90	23.47
ECONOMIC ANALYSIS OUTPUT:										
Annual Capacity Factor	%/yr	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
Equivalent Full Load Hours	Hr's	7,880	7,880	7,880	7,880	7,880	7,880	7,880	7,880	7,880
Used for Potential to Emit (MW-hours@100%CF & Availability)	Mw-Hr/yr	2,797,154	2,773,596	2,827,155	4,198,317	4,163,290	4,246,345	6,542,808	6,486,823	6,614,840

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Ultra-Supercritical

		Ultra-Supercritical	Ultra-Supercritical	Ultra-Supercritical	Ultra-Supercritical	Ultra-Supercritical	Ultra-Supercritical	Ultra-Supercritical	Ultra-Supercritical	Ultra-Supercritical
Base set-up for meeting Target BACT limits for NOX & SO2	**UNITS**	**400MW - Ultra-Supercritical PC, Bituminous**	**400MW - Ultra-Supercritical PC, Lignite**	**400MW - Ultra-Supercritical PC, PRB**	**600MW - Ultra-Supercritical PC, Bituminous**	**600MW - Ultra-Supercritical PC, Lignite**	**600MW - Ultra-Supercritical PC, PRB**	**900MW - Ultra-Supercritical PC, Bituminous**	**900MW - Ultra-Supercritical PC, Lignite**	**900MW - Ultra-Supercritical PC, PRB**
Capital costs	$1,000									
Direct & Indirect Costs $1000	$1,000	1,716,256	1,791,529	1,602,263	2,188,954	2,284,959	2,043,564	2,791,846	2,914,296	2,606,412
$/kW Capital Cost based on net summer output	$/net-kw	4,835	5,090	4,466	4,109	4,325	3,792	3,362	3,540	3,105
Capital Costs										
Costs in year 2008 dollars	$1,000	1,716,256	1,791,529	1,602,263	2,188,954	2,284,959	2,043,564	2,791,846	2,914,296	2,606,412
Fixed O&M Costs										
Fixed O&M Costs	$1,000	12,947	12,947	12,947	15,756	15,756	15,756	19,610	19,610	19,610
Variable O&M Costs ($/yr)										
Limestone Reagent	$1,000	1,419	737	0	2,118	1,100	0	3,293	1,711	0
Lime Reagent for Dry-FGD	$1,000	0	0	678	0	0	1,013	0	0	1,575
Activated Carbon	$1,000	0	1,012	920	0	1,511	1,374	0	2,349	2,136
Water	$1,000	240	296	192	387	387	387	580	580	580
Bottom Ash Sale/Disposal	$1,000	417	1,584	273	622	2,364	408	967	3,676	634
Fly ash sale/Disposal	$1,000	1,662	6,330	1,089	2,481	9,449	1,625	3,859	14,693	2,527
Gypsum sale/Disposal	$1,000	2,919	1,523	288	4,357	2,273	533	6,776	3,534	828
AC Waste Disposal	$1,000	0	9	8	0	14	12	0	21	19
Ammonia	$1,000	442	352	339	497	525	507	773	817	788
SCR-Catalyst Replacement	$1,000	673	673	673	1,010	1,010	1,010	1,515	1,515	1,515
Bags for Baghouse	$1,000	199	228	218	317	358	326	493	557	507
SO2 Allowances	$1,000	624	527	509	932	787	759	1,449	1,224	1,181
NOx Allowances	$1,000	1,873	1,978	1,908	2,796	2,952	2,848	4,348	4,590	4,428
Other	$1,000	1,399	1,388	1,414	2,100	2,083	2,124	3,273	3,245	3,309
Sulfur Sale	$1,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	$1,000	11,013	16,636	8,511	17,617	24,813	12,925	27,325	38,512	20,026
Variable O&M Costs	$/MWh	3.94	6.00	3.01	3.69	5.69	3.04	3.67	5.67	3.03
Total Non-Fuel O&M Cost	$1,000	23,960	29,583	21,458	33,373	40,569	28,681	46,935	58,122	39,636
Total Non-Fuel O&M Cost	$/MWh	8.56	10.66	7.59	7.95	9.74	6.75	7.17	8.96	5.99

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Number of BFW Heaters		**8 (HARP)**	**8 (HARP)**	**8 (HARP)**	**8 (HARP)**	**8 (HARP)**	**8 (HARP)**	**8 (HARP)**	**8 (HARP)**	**8 (HARP)**
Number of FGD Absorbers		**1**	**1**	**1**	**1**	**1**	**2**	**1**	**1**	**3**
Number of wet ESPs		**1**	**0**	**0**	**2**	**0**	**0**	**3**	**0**	**0**
Number of Pulverizers		**5**	**6**	**5**	**6**	**7**	**6**	**7**	**8**	**7**
SO2		**Wet FGD**	**Wet FGD**	**Dry FGD**	**Wet FGD**	**Wet FGD**	**Dry FGD**	**Wet FGD**	**Wet FGD**	**Dry FGD**
NOX		**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**High Dust SCR**
Primary Particulate Control		**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**	**Baghouse**
Secondary Particulate Control		**Wet ESP**	**None**	**None**	**Wet ESP**	**None**	**None**	**Wet ESP**	**None**	**None**
Mercury Control		**Inherent**	**ACI-w/BGH**	**ACI-w/BGH**	**Inherent**	**ACI-w/BGH**	**ACI-w/BGH**	**Inherent**	**ACI-w/BGH**	**ACI-w/BGH**
PLANT CONFIGURATION: (Gross-MW)		**1x400**	**1x400**	**1x400**	**1x600**	**1x600**	**1x600**	**1x900**	**1x900**	**1x900**
NO. OF STEAM GENERATORS		1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler	1 Boiler
Main Steam Pressure	psig	4515	4515	4515	4515	4515	4515	4515	4515	4515
Main Steam Temperature	°F	1300	1300	1300	1300	1300	1300	1300	1300	1300
Hot Reheat Temperature	°F	1300	1300	1300	1300	1300	1300	1300	1300	1300
NO. OF STEAM TURBINES		1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine	1 Turbine
SOx CONTROL:		Wet FGD	Wet FGD	Dry FGD	Wet FGD	Wet FGD	Dry FGD	Wet FGD	Wet FGD	Dry FGD
Uncontrolled SO2 Emission Rate	lb/mmBtu	4.32	2.14	0.52	4.32	2.14	0.52	4.32	2.14	0.52
Target "Permit" SO_2 Emission Rate	lb/mmBtu	0.10	0.08	0.08	0.10	0.08	0.08	0.10	0.08	0.08
SULFUR REMOVAL percent required meet Target "Permit" Rate	%	97.68	96.27	84.76	97.68	96.27	84.76	97.68	96.27	84.76
Typical Maximum SO2 Removal Guarantee from Vendor	%	98.15	97.20	84.76	98.15	97.20	84.76	98.15	97.20	84.76
NOx CONTROL:		SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR
Uncontrolled Rate from Furnace	lb/mmBtu	0.25	0.20	0.20	0.25	0.20	0.20	0.25	0.20	0.20
Target "Permit" NOx Emission Rate	lb/mmBtu	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
PARTICULATE CONTROL		Baghouse	Baghouse	Baghouse	Baghouse	Baghouse	Baghouse	Baghouse	Baghouse	Baghouse
Target "Permit" Emission Rate	lb/mmBtu	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Specified Design Guarantee from vendor	lb/mmBtu	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
Mercury Control		Inherent	ACI-w/BGH	ACI-w/BGH	Inherent	ACI-w/BGH	ACI-w/BGH	Inherent	ACI-w/BGH	ACI-w/BGH
Cooling Method		MD-CT	MD-CT	MD-CT	MD-CT	MD-CT	MD-CT	MD-CT	MD-CT	MD-CT
PLANT PERFORMANCE:										
Net Plant Heat Rate, HHV	Btu/net-kWh	8,349	8,882	8,414	8,305	8,834	8,363	8,279	8,808	8,341
Gross Plant Output	**Gross-kW**	**400,003**	**400,003**	**400,003**	**600,004**	**600,004**	**600,004**	**900,000**	**900,000**	**900,000**
Net Plant Output (based on Annual Average Conditions)	Net-kW	356,023	353,361	359,831	534,356	530,399	540,452	832,772	826,437	841,915
Gross Plant Heat Rate, HHV	Btu/gross-kWh	7,431	7,846	7,569	7,396	7,809	7,533	7,660	8,088	7,802
Auxiliary Power	kW	43,980	46,642	40,172	65,648	69,605	59,552	67,228	73,563	58,085
Turbine Heat Rate	Btu/kWh	6,504	6,504	6,504	6,474	6,474	6,474	6,706	6,706	6,706
Primary Fuel Feed Rate per Boiler	lb/hr	255,563	525,904	361,226	381,526	785,109	539,268	592,726	1,219,711	837,787
Primary Fuel Feed Rate per Boiler	Tons/hr	128	263	181	191	393	270	296	610	419
Primary Fuel Feed Rate per Boiler	lb/net-MWh	718	1,488	1,004	714	1,480	998	712	1,476	995
Full load Heat input to Boiler	mmBtu's/hr	2,973	3,139	3,028	4,438	4,685	4,520	6,894	7,279	7,022
Secondary Fuel Feed Rate	lb/hr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Secondary Fuel Feed Rate	lb/net-MWh	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lime/Limestone Feed Rate	lb/hr	22,516	11,701	1,700	33,614	17,468	2,538	52,221	27,137	3,942
Lime/Limestone Feed Rate	lb/net-MWh	63.2	33.1	4.7	62.9	32.9	4.7	62.7	32.8	4.7
Ammonia Feed Rate(Anhydrous)	lb/hr	234	186	180	263	278	268	409	432	416
Ammonia Feed Rate	lb/net-MWh	0.657	0.527	0.499	0.492	0.524	0.496	0.491	0.522	0.495
Activated Carbon Injection Rate	lb/hr	0	110	100	0	163	149	0	254	231
Activated Carbon Injection Rate	lb/net-MWh	0.00	0.31	0.28	0.00	0.31	0.28	0.00	0.31	0.27

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Water Consumption										
Cycle Make-up & Misc. Services	gpm	494	614	394	800	800	800	1204	1204	1204
Cooling Tower/lake make-up	gpm	4,272	4,240	4,318	6,412	6,365	6,485	9,993	9,917	10,103
Total Water	gpm	4,766	4,854	4,712	7,213	7,165	7,286	11,197	11,121	11,307
Water Consumption	gal/net-MWh	803	824	786	810	811	809	807	807	806
FUEL ANALYSIS:		Bituminous	Lignite	PRB	Bituminous	Lignite	PRB	Bituminous	Lignite	PRB
Ultimate Analysis										
Carbon	%	63.75	36.27	50.25	63.75	36.27	50.25	63.75	36.27	50.25
Sulfur	**%**	**2.51**	**0.64**	**0.22**	**2.51**	**0.64**	**0.22**	**2.51**	**0.64**	**0.22**
Oxygen	%	6.88	10.76	13.55	6.88	10.76	13.55	6.88	10.76	13.55
Hydrogen	%	4.50	2.42	3.41	4.50	2.42	3.41	4.50	2.42	3.41
Nitrogen	%	1.25	0.71	0.65	1.25	0.71	0.65	1.25	0.71	0.65
Chlorine	%	0.29	0.00	0.00	0.29	0.00	0.00	0.29	0.00	0.00
Ash	%	9.70	17.92	4.50	9.70	17.92	4.50	9.70	17.92	4.50
Moisture	%	11.12	31.24	27.40	11.12	31.24	27.40	11.12	31.24	27.40
Gross Higher Heating Value (Dulong)	Btu/lb	11,631	5,968	8,382	11,631	5,968	8,382	11,631	5,968	8,382
SORBENT ANALYSIS:										
CaCO3	%	90	90	0	90	90	0	90	90	0
MgCO3	%	5	5	0	5	5	0	5	5	0
CaO	%	0	0	90	0	0	90	0	0	90
Ash/Inerts	%	5	5	10	5	5	10	5	5	10
Moisture	%	0	0	0	0	0	0	0	0	0
STEAM GENERATOR DATA (Per Boiler):										
Theoretical Air	lb/lb-fuel	8.70	4.57	6.39	8.70	4.57	6.39	8.70	4.57	6.39
Theoretical Dry Gas	lb/lb-fuel	9.09	4.87	6.76	9.09	4.87	6.76	9.09	4.87	6.76
Actual Dry Gas	lb/lb-fuel	10.83	5.78	8.04	10.83	5.78	8.04	10.83	5.78	8.04
Excess Air	%	20	20	20	20	20	20	20	20	20
Total Dry Air Flow	lb/lb-fuel	10.45	5.49	7.67	10.45	5.49	7.67	10.45	5.49	7.67
Ambient Air Moisture	lb/lb-lair	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025
Total Air Flow	lb/lb-fuel	10.71	5.63	7.86	10.71	5.63	7.86	10.71	5.63	7.86
Flue Gas Moisture Flow	lb/lb-fuel	0.774	0.666	0.770	0.774	0.666	0.770	0.774	0.666	0.770
Products of Combustion	lb/lb-fuel	11.61	6.45	8.81	11.61	6.45	8.81	11.61	6.45	8.81
Air Heater Leakage	%	5	5	5	5	5	5	5	5	5
Air Heater Inlet Temperature	°F	100	100	100	100	100	100	100	100	100
Infiltration	%	5	5	5	5	5	5	5	5	5
Exit Flue Gas Temperature	°F	310	305	280	310	305	280	310	305	280
Flue Gas Temp. Uncorrected	°F	319	314	288	319	314	288	319	314	288
Flue Gas Flow Rate (per boiler)	lb/hr	3,217,082	3,661,874	3,443,108	4,802,739	5,466,723	5,140,158	7,461,374	8,492,863	7,985,560
Flue Gas Flow Rate	acfm	1,075,903	1,216,704	1,106,630	1,606,201	1,816,388	1,652,069	2,495,339	2,821,861	2,566,594
Combustion Air Flow	lb/hr	2,736,160	2,959,127	2,838,028	4,084,776	4,417,609	4,236,844	6,345,971	6,863,005	6,582,205
Combustion Air Flow	acfm	652,687	705,874	676,987	974,388	1,053,782	1,010,662	1,513,776	1,637,110	1,570,127
Stack Flue Gas Temperature	°F	135	140	170	135	140	170	135	140	170
Stack Flue Gas Flow Rate per Flue	acfm	880,355	1,010,493	1,016,816	1,314,270	1,508,541	1,517,988	2,041,806	2,343,603	2,358,290
Radiation Loss	%	0.198	0.198	0.198	0.187	0.187	0.187	0.177	0.177	0.177
Dry Gas Heat Loss	%	5.89	5.96	5.19	5.89	5.96	5.19	5.89	5.96	5.19
Fuel Moisture Loss	%	1.07	5.84	3.62	1.07	5.84	3.62	1.07	5.84	3.62
Hydrogen in Fuel Loss	%	3.89	4.07	4.06	3.89	4.07	4.06	3.89	4.07	4.06
Air Moisture Heat Loss	%	0.237	0.236	0.206	0.237	0.236	0.206	0.237	0.236	0.206
Carbon Loss	%	0.50	0.10	0.10	0.50	0.10	0.10	0.50	0.10	0.10
Unaccounted Loss	%	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Manufacturer's Margin	%	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50

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Total Boiler Loss	%	12.48	17.11	14.07	12.47	17.10	14.06	12.46	17.09	14.05
Boiler Efficiency	%	87.52	82.89	85.93	87.53	82.90	85.94	87.54	82.91	85.95
Total Heat Output from Boiler	mmBtu/hr	2,601.62	2,601.62	2,601.62	3,884.43	3,884.43	3,884.43	6,035.40	6,035.40	6,035.40
Main Steam Flow	lb/hr	2,110,500	2,110,500	2,110,500	3,136,701	3,136,701	3,136,701	4,848,440	4,848,440	4,848,440
STEAM TURBINE/CYCLE DATA (Per Turbine):										
Turbine Back Pressure	in HgA	2	2	2	2	2	2	2	2	2
Steam Turbine Gross Output	kW	400,003	400,003	400,003	600,004	600,004	600,004	900,000	900,000	900,000
LP Turbine Exhaust to Condenser	lb/hr	1,289,272	1,289,272	1,289,272	1,915,626	1,915,626	1,915,626	2,641,475	2,641,475	2,641,475
Exhaust Energy	Btu/lb	1,040.80	1,040.80	1,040.80	1,041.30	1,041.30	1,041.30	1,040.10	1,040.10	1,040.10
Condensate Enthalpy	Btu/lb	69.1	69.1	69.1	69.1	69.1	69.1	69.1	69.1	69.1
Heat Rejection from LP Turbine	mmBtu/hr	1,253	1,253	1,253	1,862	1,862	1,862	2,565	2,565	2,565
BFP Turbine Drive Steam Flow	lb/hr	0	0	0	0	0	0	333,700	333,700	333,700
BFP Turbine Exhaust Enthalpy	Btu/lb	0	0	0	0	0	0	1,085	1,085	1,085
Heat Rejection from BFP Turbine	Btu/hr	0	0	0	0	0	0	324	324	324
Total Heat Rejected to Condenser	mmBtu/hr	1,253	1,253	1,253	1,862	1,862	1,862	2,889	2,889	2,889
Circulating Water Temp. Rise	°F	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Circulating Water Flow	gpm	132,688	132,688	132,688	197,046	197,046	197,046	306,902	306,902	306,902
Number of Cooling Tower Cells		14	14	14	20	20	20	30	30	30
Total Circ. Water Flow	gpm	132,688	132,688	132,688	197,046	197,046	197,046	306,902	306,902	306,902
Service Water Flow	gpm	6,634	6,634	6,634	9,852	9,852	9,852	15,345	15,345	15,345
Total Cooling Water Requirement	gpm	139,322	139,322	139,322	206,898	206,898	206,898	322,247	322,247	322,247
PLANT AUXILIARY POWER:										
Induced Draft Fan Pressure Rise	"wc	44.0	44.0	41.8	44.0	44.0	41.8	44.0	44.0	41.8
Boiler	"w.c	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Econ Outlet to SCR outlet	"w.c	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
SCR Outlet to AH Outlet	"w.c	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
AH Outlet to ESP Outlet	"w.c	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AH/ESP Outlet to COHPAC or Dry FGD/BH Outlet	"w.c	8.0	8.0	16.0	8.0	8.0	16.0	8.0	8.0	16.0
COHPAC/Dry FGD BH Outlet to stack	"w.c	0.0	0.0	2.0	0.0	0.0	2.0	0.0	0.0	2.0
ID inlet to Wet FGD outlet	"w.c	8.0	8.0	0.0	8.0	8.0	0.0	8.0	8.0	0.0
Wet FGD outlet to stack outlet	"w.c	4.0	4.0	0.0	4.0	4.0	0.0	4.0	4.0	0.0
Total ID fan static pressure	"w.c	40.0	40.0	38.0	40.0	40.0	38.0	40.0	40.0	38.0
Percent Total Air to FD Fan	%	70	70	70	70	70	70	70	70	70
Forced Draft Fan Pressure Rise	"wc	20	20	20	20	20	20	20	20	20
Percent Total Air to PA Fan	%	30	30	30	30	30	30	30	30	30
Primary Air Fan Pressure Rise	"wc	40	40	40	40	40	40	40	40	40
Percent Total Air to SA Fan	%	0	0	0	0	0	0	0	0	0
Secondary Air Fan Pressure Rise	"wc	15	15	15	15	15	15	15	15	15
Condensate P/P	%	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
Circulating Water P/P	%	0.40	0.40	0.40	0.40	0.40	0.40	0.41	0.41	0.41
Cooling Towers	%	0.72	0.72	0.72	0.69	0.69	0.69	0.69	0.69	0.69
Feedwater P/P	%	3.60	3.60	3.60	3.60	3.60	3.60	0.00	0.00	0.00
Subtotal CWS	%	5.08	5.08	5.08	5.04	5.04	5.04	1.46	1.46	1.46
Forced Draft Fan	%	0.32	0.34	0.33	0.32	0.34	0.33	0.33	0.35	0.34
Induced Draft Fan	%	1.85	2.09	1.65	1.84	2.08	1.64	1.91	2.16	1.70
Primary Air Fan	%	0.28	0.30	0.29	0.27	0.30	0.28	0.28	0.31	0.30
Pulverizer	%	0.46	0.95	0.65	0.46	0.94	0.65	0.47	0.98	0.67
Fuel Handling	%	0.11	0.20	0.15	0.11	0.20	0.15	0.11	0.21	0.15
Ash Handling	%	0.17	0.55	0.13	0.17	0.55	0.13	0.18	0.57	0.13
Wet ESP for H2SO4 collection	%	0.15	0.00	0.00	0.15	0.00	0.00	0.15	0.00	0.00
Baghouse	%	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
FGD	%	1.25	0.82	0.45	1.25	0.82	0.38	1.25	0.82	0.38
Transformer Losses	%	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Miscellaneous	.	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

PQA Study
Technology Spreadsheet
Efficiency/Heat Rate for New Coal-Fired Power Plants
Advanced Ultra-Supercritical

		Adv. USC	Adv. USC	Adv. USC	Adv. USC	Adv. USC	Adv. USC	Adv. USC	Adv. USC	Adv. USC
Base set-up for meeting Target BACT limits for NOX & SO2	**UNITS**	**400MW - Adv. Ultra Supercritical PC, Bituminous**	**400MW - Adv. Ultra Supercritical PC, Lignite**	**400MW - Adv. Ultra Supercritical PC, PRB**	**600MW - Adv. Ultra Supercritical PC, Bituminous**	**600MW - Adv. Ultra Supercritical PC, Lignite**	**600MW - Adv. Ultra Supercritical PC, PRB**	**900MW - Adv. Ultra Supercritical PC, Bituminous**	**900MW - Adv. Ultra Supercritical PC, Lignite**	**900MW - Adv. Ultra Supercritical PC, PRB**
TOTAL Auxiliary Power	%	10.99	11.66	10.04	10.94	11.60	9.93	7.47	8.17	6.45
Net Unit Heat Rate	Btu/kWh	8,349	8,882	8,414	8,305	8,834	8,363	8,279	8,808	8,341
Plant Efficiency	%	40.9	38.4	40.6	41.1	38.6	40.8	41.2	38.7	40.9
ECONOMIC ANALYSIS INPUT:										
2008 to COD	years	5	5	5	5	5	5	5	5	5
Start of Engineering to COD	months	55	55	55	55	55	55	55	55	55
Operating Life	years	35	35	35	35	35	35	35	35	35
Fixed Labor Costs	$	7,187,292	7,187,292	7,187,292	8,556,300	8,556,300	8,556,300	10,609,812	10,609,812	10,609,812
Fixed Non-Labor O&M Costs	$	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Fixed O&M Costs	$	7,187,292	7,187,292	7,187,292	8,556,300	8,556,300	8,556,300	10,609,812	10,609,812	10,609,812
Fixed O&M Costs	$/net kW-yr	20.19	20.34	19.97	16.01	16.13	15.83	12.74	12.84	12.60
Property Taxes	$/year	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
FGD Reagent Cost										
$/ton, delivered		15.00	15.00	95.00	15.00	15.00	95.00	15.00	15.00	95.00
Activated Carbon										
$/ton, delivered		2200	2200	2200	2200	2200	2200	2200	2200	2200
SCR Catalyst										
$/M^3		6000	6000	6000	6000	6000	6000	6000	6000	6000
Ammonia (Anhydrous)										
$/ton, delivered		450	450	450	450	450	450	450	450	450
Water Cost										
$/1000 gallons		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Fly Ash Sales	$/ton	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fly Ash Disposal	$/ton	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Bottom Ash Sales	$/ton	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Bottom Ash Disposal	$/ton	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Activated Carbon waste	$/ton	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
FGD Waste Sale	$/ton	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FGD Waste Disposal	$/ton	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Other Variable O&M Costs	$/net-MWh	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
SO2 Allowance Market Cost										
$/ton		$500	$500	$500	$500	$500	$500	$500	$500	$500
NOX Allowance Market Cost										
$/ton		$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000
Sulfur Byproduct										
$/ton		$0	$0	$0	$0	$0	$0	$0	$0	$0
Equivalent Availability Factor	%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
Replacement Power cost	$/gross-kWh	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Fuel Cost Delivered	$/mmBtu	1.70	1.50	1.40	1.70	1.50	1.40	1.70	1.50	1.40
$/ton, delivered		39.55	17.90	23.47	39.55	17.90	23.47	39.55	17.90	23.47
ECONOMIC ANALYSIS OUTPUT:										
Annual Capacity Factor	%/yr	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
Equivalent Full Load Hours	Hr's	7,880	7,880	7,880	7,880	7,880	7,880	7,880	7,880	7,880
Used for Potential to Emit (MW-hours@100%CF & Availability)	Mw-Hr/yr	2,805,462	2,784,486	2,835,469	4,210,725	4,179,542	4,258,762	6,562,241	6,512,322	6,634,288

PQA Study
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Efficiency/Heat Rate for New Coal-Fired Power Plants
Advanced Ultra-Supercritical

		Adv. USC	Adv. USC	Adv. USC	Adv. USC	Adv. USC	Adv. USC	Adv. USC	Adv. USC	Adv. USC
Base set-up for meeting Target BACT limits for NOX & SO2	**UNITS**	**400MW - Adv. Ultra Supercritical PC, Bituminous**	**400MW - Adv. Ultra Supercritical PC, Lignite**	**400MW - Adv. Ultra Supercritical PC, PRB**	**600MW - Adv. Ultra Supercritical PC, Bituminous**	**600MW - Adv. Ultra Supercritical PC, Lignite**	**600MW - Adv. Ultra Supercritical PC, PRB**	**900MW - Adv. Ultra Supercritical PC, Bituminous**	**900MW - Adv. Ultra Supercritical PC, Lignite**	**900MW - Adv. Ultra Supercritical PC, PRB**
Capital costs	$1,000									
Direct & Indirect Costs $1000	$1,000	NA	NA	NA	NA	NA	NA	NA	NA	NA
$/kW Capital Cost based on net output	$/net-kw	NA	NA	NA	NA	NA	NA	NA	NA	NA
Capital Costs										
Costs in year 2008 dollars	$1,000	NA	NA	NA	NA	NA	NA	NA	NA	NA
Fixed O&M Costs										
Fixed O&M Costs	$1,000	NA	NA	NA	NA	NA	NA	NA	NA	NA
Variable O&M Costs ($/yr)										
Limestone Reagent	$1,000	1,331	692	0	1,988	1,033	0	3,088	1,605	0
Lime Reagent for Dry-FGD	$1,000	0	0	637	0	0	950	0	0	1,476
Activated Carbon	$1,000	0	950	864	0	1,418	1,289	0	2,203	2,003
Water	$1,000	234	290	186	379	379	379	570	570	570
Bottom Ash Disposal/Sale	$1,000	391	1,486	256	584	2,218	383	907	3,446	594
Fly ash sale/Disposal	$1,000	1,560	5,940	1,022	2,329	8,868	1,525	3,618	13,777	2,370
Gypsum sale/Disposal	$1,000	2,739	1,429	270	4,090	2,133	500	6,353	3,314	777
AC Waste Disposal	$1,000	0	9	8	0	13	12	0	20	18
Ammonia	$1,000	415	330	318	467	493	475	725	766	739
SCR-Catalyst Replacement	$1,000	673	673	673	1,010	1,010	1,010	1,515	1,515	1,515
Bags for Baghouse	$1,000	186	214	205	297	336	306	462	523	475
SO2 Allowances	$1,000	586	495	477	875	739	713	1,359	1,148	1,107
NOx Allowances	$1,000	1,758	1,856	1,790	2,624	2,770	2,673	4,077	4,304	4,152
Other	$1,000	1,403	1,393	1,418	2,106	2,091	2,130	3,283	3,258	3,319
Sulfur Sale	$1,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	$1,000	45,576	15,757	8,126	16,747	23,501	12,344	25,956	36,447	19,115
Variable O&M Costs	$/MWh	15.76	5.41	2.86	3.50	5.37	2.90	3.48	5.35	2.88
Total Non-Fuel O&M Cost	$1,000	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Non-Fuel O&M Cost	$/MWh	NA	NA	NA	NA	NA	NA	NA	NA	NA

APPENDIX B

PC POWER PLANT COST ESTIMATE DETAILS

Sargent & Lundy

12301-003
BJD - 12/10/2008
PAG - 12/10/2008

PQA
Greenfield Coal Fired PC Plants
Order of Magnitude Cost Study
Summary of Estimated Project Costs
Based on Bituminous Coal

Unit Size, MW Gross	400	600	900	400	600	900	400	600	900
Unit Size, MW Net	359	539	828	355	533	830	355	533	830
Configuration	Subcritical PC	Subcritical PC	Subcritical PC	Supercritical PC	Supercritical PC	Supercritical PC	Ultra- Supercritical PC	Ultra- Supercritical PC	Ultra- Supercritical PC
Land and Land Rights	not included	not included	not included	not included	not included	not included	not included	not included	not included
Structures and Improvements	109,923,000	140,198,000	178,812,000	109,923,000	140,198,000	178,812,000	109,923,000	140,198,000	178,812,000
Boiler Plant	579,411,000	738,995,000	942,532,000	603,553,000	769,786,000	981,804,000	635,319,000	810,301,000	1,033,478,000
Turbine Plant	107,723,000	137,393,000	175,234,000	108,264,000	138,083,000	176,115,000	109,358,000	139,478,000	177,894,000
Misc. Power Plant Equipment	11,540,000	14,719,000	18,773,000	11,540,000	14,719,000	18,773,000	11,540,000	14,719,000	18,773,000
Main Power System	10,059,000	12,829,000	16,363,000	10,059,000	12,829,000	16,363,000	10,059,000	12,829,000	16,363,000
Auxiliary Power System	13,652,000	17,412,000	22,208,000	13,652,000	17,412,000	22,208,000	13,652,000	17,412,000	22,208,000
Emergency Power System	784,000	1,000,000	1,275,000	784,000	1,000,000	1,275,000	784,000	1,000,000	1,275,000
Electrical BOP.	62,835,000	80,141,000	102,214,000	62,835,000	80,141,000	102,214,000	62,835,000	80,141,000	102,214,000
Substation and Switchyard Structures and Facilities	957,000	1,220,000	1,556,000	957,000	1,220,000	1,556,000	957,000	1,220,000	1,556,000
Substation and Switchyard Equipment	9,050,000	11,543,000	14,722,000	9,050,000	11,543,000	14,722,000	9,050,000	11,543,000	14,722,000
Initial Fills	466,000	594,000	758,000	466,000	594,000	758,000	466,000	594,000	758,000
Startup Personnel & Craft Startup Support	4,609,000	5,879,000	7,498,000	4,609,000	5,879,000	7,498,000	4,609,000	5,879,000	7,498,000
Consumables	2,882,000	3,676,000	4,689,000	2,882,000	3,676,000	4,689,000	2,882,000	3,676,000	4,689,000
Overtime Inefficiency & Overtime Premium Pay	49,658,000	63,335,000	80,779,000	49,658,000	63,335,000	80,779,000	49,658,000	63,335,000	80,779,000
Per Diem (Subsistence)	55,537,000	70,833,000	90,342,000	55,537,000	70,833,000	90,342,000	55,537,000	70,833,000	90,342,000
EPC Fees (0%)	-	-	-	-	-	-	-	-	-
Subtotal Direct Project Costs	**1,019,086,000**	**1,299,767,000**	**1,657,755,000**	**1,043,769,000**	**1,331,248,000**	**1,697,908,000**	**1,076,629,000**	**1,373,158,000**	**1,751,361,000**
	-								
Indirect Project Costs.	76,066,000	97,016,000	123,737,000	77,908,000	99,366,000	126,734,000	80,361,000	102,495,000	130,724,000
Contingency (15%)	164,273,000	209,517,000	267,224,000	168,252,000	214,592,000	273,696,000	173,549,000	221,348,000	282,313,000
Owner's Costs (3%)	32,855,000	41,903,000	53,445,000	33,650,000	42,918,000	54,739,000	34,710,000	44,270,000	56,463,000
Operating Spare Parts (1%)	10,952,000	13,968,000	17,815,000	11,217,000	14,306,000	18,246,000	11,570,000	14,757,000	18,821,000
Escalation (4% Annual Rate)	198,399,000	253,043,000	322,737,000	203,204,000	259,171,000	330,553,000	209,601,000	267,330,000	340,959,000
Interest During Construction (6% Annual Rate)	122,896,000	156,745,000	199,916,000	125,873,000	160,542,000	204,759,000	129,836,000	165,596,000	211,205,000
Subtotal Project Costs	**1,624,527,000**	**2,071,959,000**	**2,642,629,000**	**1,663,873,000**	**2,122,143,000**	**2,706,635,000**	**1,716,256,000**	**2,188,954,000**	**2,791,846,000**
$/kW Net	**4,523**	**3,844**	**3,190**	**4,686**	**3,982**	**3,262**	**4,835**	**4,109**	**3,362**

Notes:

1. The contracting scheme is based on multiple lump sum contracts. An EPC contract could add an additional 10-15% to the cost of the plant.
2. Total Project Cost represents cost at completion for a project started 01/2009 and completed 12/2013, a 5 year overall schedule.
3. Indirect Project Costs include engineering and construction management.
4. The labor cost is based on Gulf region of the U.S. Adjustments will be required for other regions of the country.
5. The costs provided are within a +/-30% range.
6. Adjustments for Bituminous coal fired plant from PRB coal fired plant:
   Smaller Boiler and smaller Boiler Building
   Wet FGD with Wet ESP in place of Dry FGD and no Wet ESP
   Lined Chimney
   Greater Auxiliary Power requirement
   Greater Electrical BOP

PQA
Greenfield Coal Fired PC Plants
Order of Magnitude Cost Study
Summary of Estimated Project Costs
Based on PRB Coal

Unit Size, MW Gross	400	600	900	400	600	900	400	600	900
Unit Size, MW Net	363	545	838	359	539	839	359	539	839
Configuration	Subcritical PC	Subcritical PC	Subcritical PC	Supercritical PC	Supercritical PC	Supercritical PC	Ultra- Supercritical PC	Ultra- Supercritical PC	Ultra- Supercritical PC
Land and Land Rights	not included	not included	not included	not included	not included	not included	not included	not included	not included
Structures and Improvements	109,923,000	140,198,000	178,812,000	109,923,000	140,198,000	178,812,000	109,923,000	140,198,000	178,812,000
Boiler Plant	522,039,000	665,821,000	849,204,000	543,790,000	693,563,000	884,587,000	572,410,000	730,066,000	931,144,000
Turbine Plant	107,723,000	137,393,000	175,234,000	108,264,000	138,083,000	176,115,000	109,358,000	139,478,000	177,894,000
Misc. Power Plant Equipment	11,540,000	14,719,000	18,773,000	11,540,000	14,719,000	18,773,000	11,540,000	14,719,000	18,773,000
Main Power System	10,059,000	12,829,000	16,363,000	10,059,000	12,829,000	16,363,000	10,059,000	12,829,000	16,363,000
Auxiliary Power System	13,600,000	17,346,000	22,123,000	13,600,000	17,346,000	22,123,000	13,600,000	17,346,000	22,123,000
Emergency Power System	784,000	1,000,000	1,275,000	784,000	1,000,000	1,275,000	784,000	1,000,000	1,275,000
Electrical BOP.	61,770,000	78,783,000	100,482,000	61,770,000	78,783,000	100,482,000	61,770,000	78,783,000	100,482,000
Substation and Switchyard Structures and Facilities	957,000	1,220,000	1,556,000	957,000	1,220,000	1,556,000	957,000	1,220,000	1,556,000
Substation and Switchyard Equipment	9,050,000	11,543,000	14,722,000	9,050,000	11,543,000	14,722,000	9,050,000	11,543,000	14,722,000
Initial Fills	466,000	594,000	758,000	466,000	594,000	758,000	466,000	594,000	758,000
Startup Personnel & Craft Startup Support	4,303,000	5,488,000	7,000,000	4,303,000	5,488,000	7,000,000	4,303,000	5,488,000	7,000,000
Consumables	2,692,000	3,433,000	4,378,000	2,692,000	3,433,000	4,378,000	2,692,000	3,433,000	4,378,000
Overtime Inefficiency & Overtime Premium Pay	46,360,000	59,129,000	75,414,000	46,360,000	59,129,000	75,414,000	46,360,000	59,129,000	75,414,000
Per Diem (Subsistence)	51,849,000	66,129,000	84,342,000	51,849,000	66,129,000	84,342,000	51,849,000	66,129,000	84,342,000
EPC Fees (0%)	-	-	-	-	-	-	-	-	-
Subtotal Direct Project Costs	**953,115,000**	**1,215,625,000**	**1,550,436,000**	**975,407,000**	**1,244,057,000**	**1,586,700,000**	**1,005,121,000**	**1,281,955,000**	**1,635,036,000**
	-								
Indirect Project Costs.	71,141,000	90,735,000	115,726,000	72,806,000	92,858,000	118,433,000	75,024,000	95,687,000	122,041,000
Contingency (15%)	153,638,000	195,954,000	249,924,000	157,232,000	200,537,000	255,770,000	162,022,000	206,646,000	263,562,000
Owner's Costs (3%)	30,728,000	39,191,000	49,985,000	31,446,000	40,107,000	51,154,000	32,404,000	41,329,000	52,712,000
Operating Spare Parts (1%)	10,243,000	13,064,000	16,662,000	10,482,000	13,369,000	17,051,000	10,801,000	13,776,000	17,571,000
Escalation (4% Annual Rate)	185,555,000	236,661,000	301,843,000	189,895,000	242,196,000	308,902,000	195,679,000	249,574,000	318,313,000
Interest During Construction (6% Annual Rate)	114,940,000	146,597,000	186,973,000	117,628,000	150,026,000	191,347,000	121,212,000	154,597,000	197,177,000
Subtotal Project Costs	**1,519,360,000**	**1,937,827,000**	**2,471,549,000**	**1,554,896,000**	**1,983,150,000**	**2,529,357,000**	**1,602,263,000**	**2,043,564,000**	**2,606,412,000**
$/kW Net	**4,186**	**3,555**	**2,951**	**4,332**	**3,679**	**3,015**	**4,466**	**3,792**	**3,105**

Notes:

1. The contracting scheme is based on multiple lump sum contracts. An EPC contract could add an additional 10-15% to the cost of the plant.
2. Total Project Cost represents cost at completion for a project started 01/2009 and completed 12/2013, a 5 year overall schedule.
3. Indirect Project Costs include engineering and construction management.
4. The labor cost is based on Gulf region of the U.S. Adjustments will be required for other regions of the country.
5. The costs provided are within a +/-30% range.

Sargent & Lundy

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MNO - 10/24/2008
PFE - 10/27/2008
Revised 11/7/2008

PQA
Greenfield Coal Fired PC Plants
Order of Magnitude Cost Study
Summary of Estimated Project Costs
Based on Lignite Coal

Unit Size, MW Gross	400	600	900	400	600	900	400	600	900
Unit Size, MW Net	356	534	821	352	528	822	352	528	823
Configuration	Subcritical PC	Subcritical PC	Subcritical PC	Supercritical PC	Supercritical PC	Supercritical PC	Ultra- Supercritical PC	Ultra- Supercritical PC	Ultra- Supercritical PC
Land and Land Rights	not included	not included	not included	not included	not included	not included	not included	not included	not included
Structures and Improvements	109,923,000	140,198,000	178,812,000	109,923,000	140,198,000	178,812,000	109,923,000	140,198,000	178,812,000
Boiler Plant	617,968,000	788,172,000	1,005,254,000	643,717,000	821,013,000	1,047,140,000	677,597,000	864,224,000	1,102,253,000
Turbine Plant	107,723,000	137,393,000	175,234,000	108,264,000	138,083,000	176,115,000	109,358,000	139,478,000	177,894,000
Misc. Power Plant Equipment	11,540,000	14,719,000	18,773,000	11,540,000	14,719,000	18,773,000	11,540,000	14,719,000	18,773,000
Main Power System	10,059,000	12,829,000	16,363,000	10,059,000	12,829,000	16,363,000	10,059,000	12,829,000	16,363,000
Auxiliary Power System	13,652,000	17,412,000	22,208,000	13,652,000	17,412,000	22,208,000	13,652,000	17,412,000	22,208,000
Emergency Power System	784,000	1,000,000	1,275,000	784,000	1,000,000	1,275,000	784,000	1,000,000	1,275,000
Electrical BOP.	62,835,000	80,141,000	102,214,000	62,835,000	80,141,000	102,214,000	62,835,000	80,141,000	102,214,000
Substation and Switchyard Structures and Facilities	957,000	1,220,000	1,556,000	957,000	1,220,000	1,556,000	957,000	1,220,000	1,556,000
Substation and Switchyard Equipment	9,050,000	11,543,000	14,722,000	9,050,000	11,543,000	14,722,000	9,050,000	11,543,000	14,722,000
Initial Fills	466,000	594,000	758,000	466,000	594,000	758,000	466,000	594,000	758,000
Startup Personnel & Craft Startup Support	4,811,000	6,136,000	7,826,000	4,811,000	6,136,000	7,826,000	4,811,000	6,136,000	7,826,000
Consumables	3,009,000	3,838,000	4,895,000	3,009,000	3,838,000	4,895,000	3,009,000	3,838,000	4,895,000
Overtime Inefficiency & Overtime Premium Pay	51,836,000	66,113,000	84,322,000	51,836,000	66,113,000	84,322,000	51,836,000	66,113,000	84,322,000
Per Diem (Subsistence)	57,973,000	73,940,000	94,305,000	57,973,000	73,940,000	94,305,000	57,973,000	73,940,000	94,305,000
EPC Fees (0%)	-	-	-	-	-	-	-	-	-
Subtotal Direct Project Costs	**1,062,586,000**	**1,355,248,000**	**1,728,517,000**	**1,088,876,000**	**1,388,779,000**	**1,771,284,000**	**1,123,850,000**	**1,433,385,000**	**1,828,176,000**
	-								
Indirect Project Costs.	79,313,000	101,158,000	129,019,000	81,275,000	103,660,000	132,211,000	83,885,000	106,989,000	136,457,000
Contingency (15%)	171,285,000	218,461,000	278,630,000	175,523,000	223,866,000	285,524,000	181,160,000	231,056,000	294,695,000
Owner's Costs (3%)	34,257,000	43,692,000	55,726,000	35,105,000	44,773,000	57,105,000	36,232,000	46,211,000	58,939,000
Operating Spare Parts (1%)	11,419,000	14,564,000	18,575,000	11,702,000	14,924,000	19,035,000	12,077,000	15,404,000	19,646,000
Escalation (4% Annual Rate)	206,867,000	263,843,000	336,512,000	211,985,000	270,371,000	344,838,000	218,794,000	279,055,000	355,914,000
Interest During Construction (6% Annual Rate)	128,143,000	163,437,000	208,451,000	131,313,000	167,480,000	213,608,000	135,531,000	172,859,000	220,469,000
Subtotal Project Costs	**1,693,870,000**	**2,160,403,000**	**2,755,430,000**	**1,735,779,000**	**2,213,853,000**	**2,823,605,000**	**1,791,529,000**	**2,284,959,000**	**2,914,296,000**
$/kW Net	**4,760**	**4,045**	**3,357**	**4,931**	**4,190**	**3,433**	**5,090**	**4,325**	**3,540**

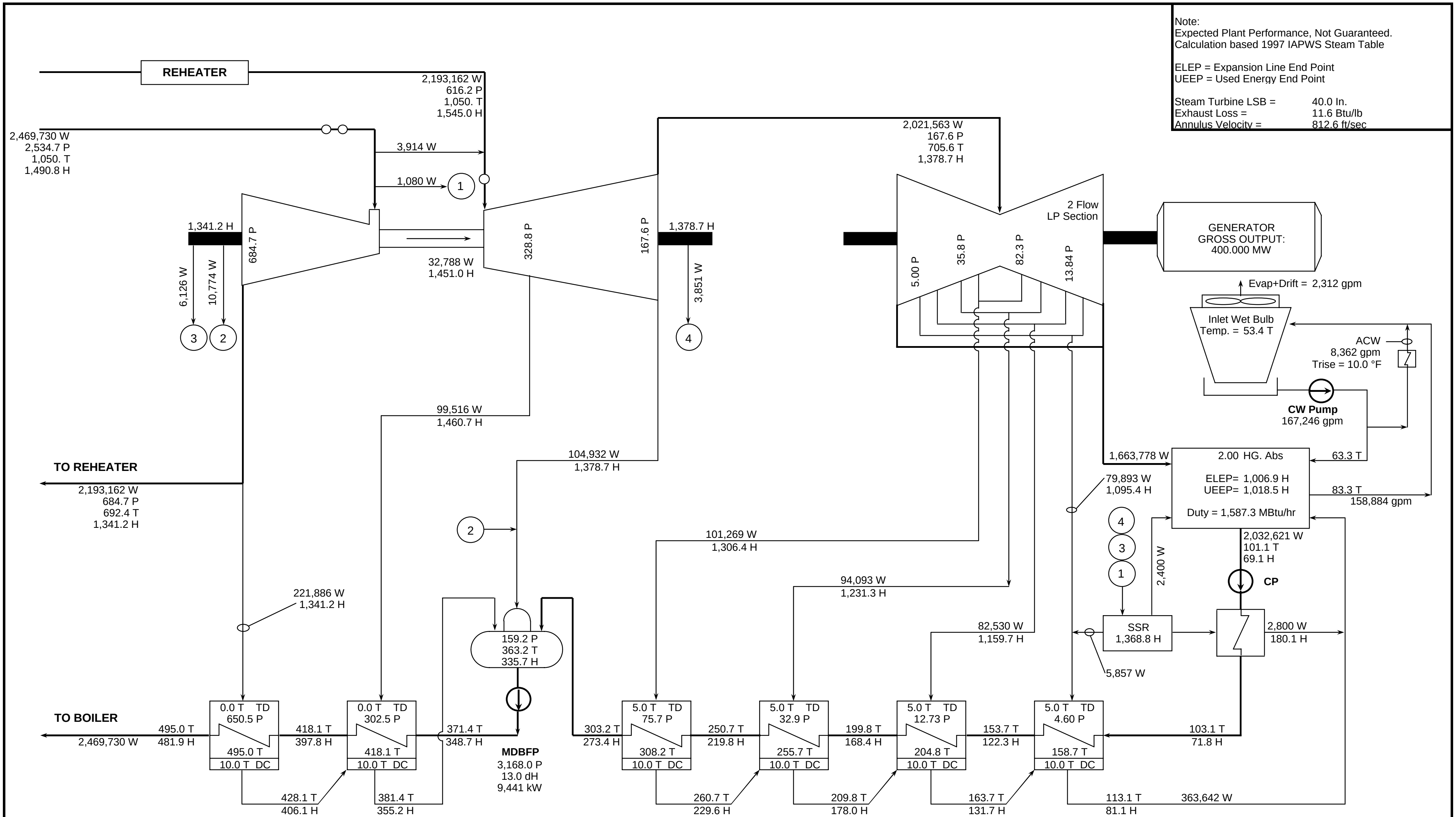
Notes:

1. The contracting scheme is based on multiple lump sum contracts. An EPC contract could add an additional 10-15% to the cost of the plant.
2. Total Project Cost represents cost at completion for a project started 01/2009 and completed 12/2013, a 5 year overall schedule.
3. Indirect Project Costs include engineering and construction management.
4. The labor cost is based on Gulf region of the U.S. Adjustments will be required for other regions of the country.
5. The costs provided are within a +/-30% range.
6. Adjustments for Lignite fired plant from Bituminous coal fired plant:

Larger Boiler and larger Boiler Building
No Wet ESP
Larger diameter Chimney
Smaller Limestone Handling & Gypsum Handling
Larger Bottom Ash & Fly Ash Handling
No Car Dumper and no Loop Track
Larger Coal Handling

APPENDIX C

PC POWER PLANT HEAT BALANCES



Ambient Dry Bulb =	59.0 T
Ambient Wet Bulb =	51.4 T
Relative Humidity =	60.0%
Site Elevation (AMSL) =	1 ft
Steam Turbine Gross =	400.0 MW

Gross Turbine Heat Rate = Heat Input / Generator Output **= 7,347 Btu/kWh**

Net Turbine Heat Rate = Heat Input / (Generator Output - Power to BFP Motor) **= 7,524 Btu/kWh**

PRELIMINARY
For Information Only

Legend:
W= Flow, lb/hr
P= Pressure, Psia
T= Temperature, °F
H= Enthalpy, Btu/lb

Drawing Release Record

Rev.	Date	Prepared	Reviewed	Approved	Purpose	Project No.:
0	11/19/2008	L.Papadopoulos			Original Issue	12301-003
						GateCycle Model/Case

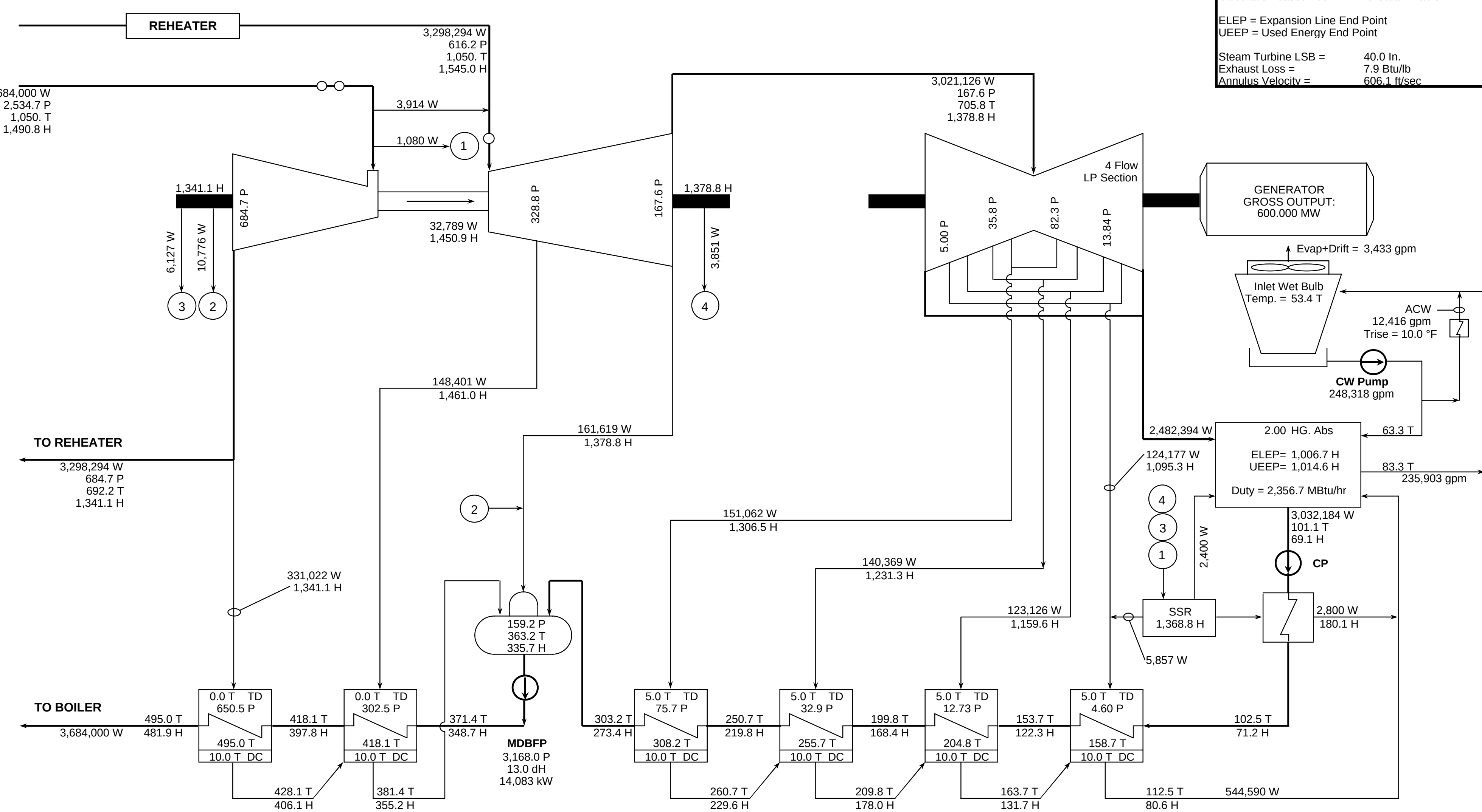
PQA STUDY
SUBCRITICAL
400 MW
2534.7 P / 1050 T / 1050 T

Sargent & Lundy LLC

Note:
Expected Plant Performance, Not Guaranteed.
Calculation based 1997 IAPWS Steam Table

ELEP = Expansion Line End Point
UEEP = Used Energy End Point

Steam Turbine LSB =	40.0 In.
Exhaust Loss =	7.9 Btu/lb
Annulus Velocity =	606.1 ft/sec



Ambient Dry Bulb =	59.0 T
Ambient Wet Bulb =	51.4 T
Relative Humidity =	60.0%
Site Elevation (AMSL) =	1 ft
Steam Turbine Gross =	600.0 MW

Gross Turbine Heat Rate = Heat Input / Generator Output **= 7,316 Btu/kWh**

Net Turbine Heat Rate = Heat Input / (Generator Output - Power to BFP Motor) **= 7,491 Btu/kWh**

PRELIMINARY
For Information Only

Legend:

W=	Flow, lb/hr
P=	Pressure, Psia
T=	Temperature, °F
H=	Enthalpy, Btu/lb

Drawing Release Record

Rev.	Date	Prepared	Reviewed	Approved	Purpose	Project No.:
0	11/19/2008	L.Papadopoulos			Original Issue	12301-003
						GateCycle Model/Case

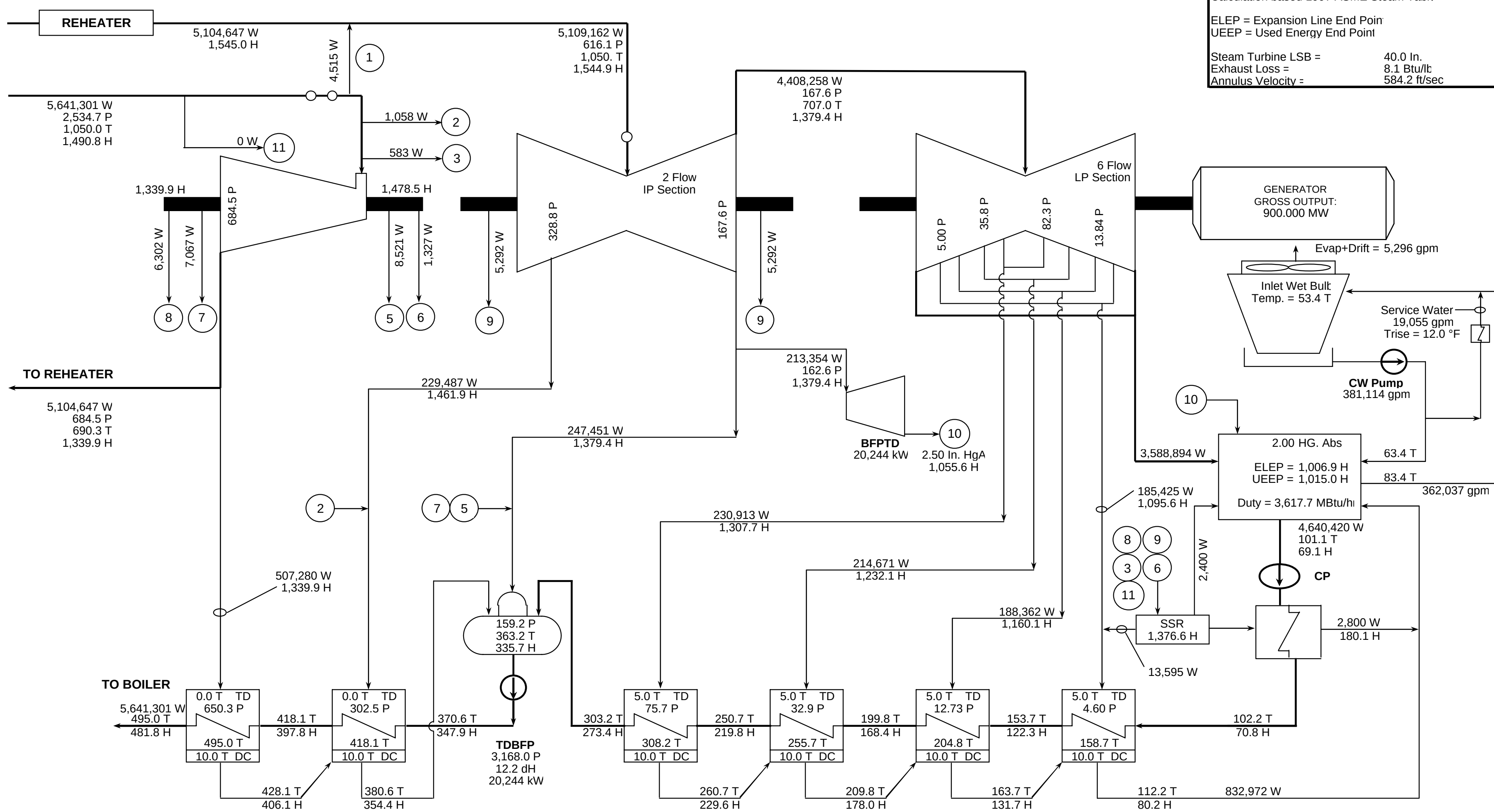
PQA STUDY
SUBCRITICAL
600 MW
2534.7 P / 1050 T / 1050 T

Sargent & Lundy LLC

Note:
Expected Plant Performance, Not Guaranteed
Calculation based 1997 ASME Steam Table

ELEP = Expansion Line End Point
UEEP = Used Energy End Point

Steam Turbine LSB =	40.0 In.
Exhaust Loss =	8.1 Btu/lb
Annulus Velocity =	584.2 ft/sec



Ambient Dry Bulb =	59.0 T
Ambient Wet Bulb =	51.4 T
Relative Humidity =	60.1%
Site Elevation (AMSL) =	1 ft
Steam Turbine Gross =	900.0 MW

Gross Turbine Heat Rate = Heat Input / (Generator Output + Aux. Turbine Outpu = 7,323 Btu/kWh

Net Turbine Heat Rate = Heat Input / Generator Outpu = 7,487 Btu/kWh

Legend:		
W=	Flow	Lb/h
P=	Pressure	Psia
T=	Temp.	°F
H=	Enthalpy	Btu/Lb

Drawing Release Record

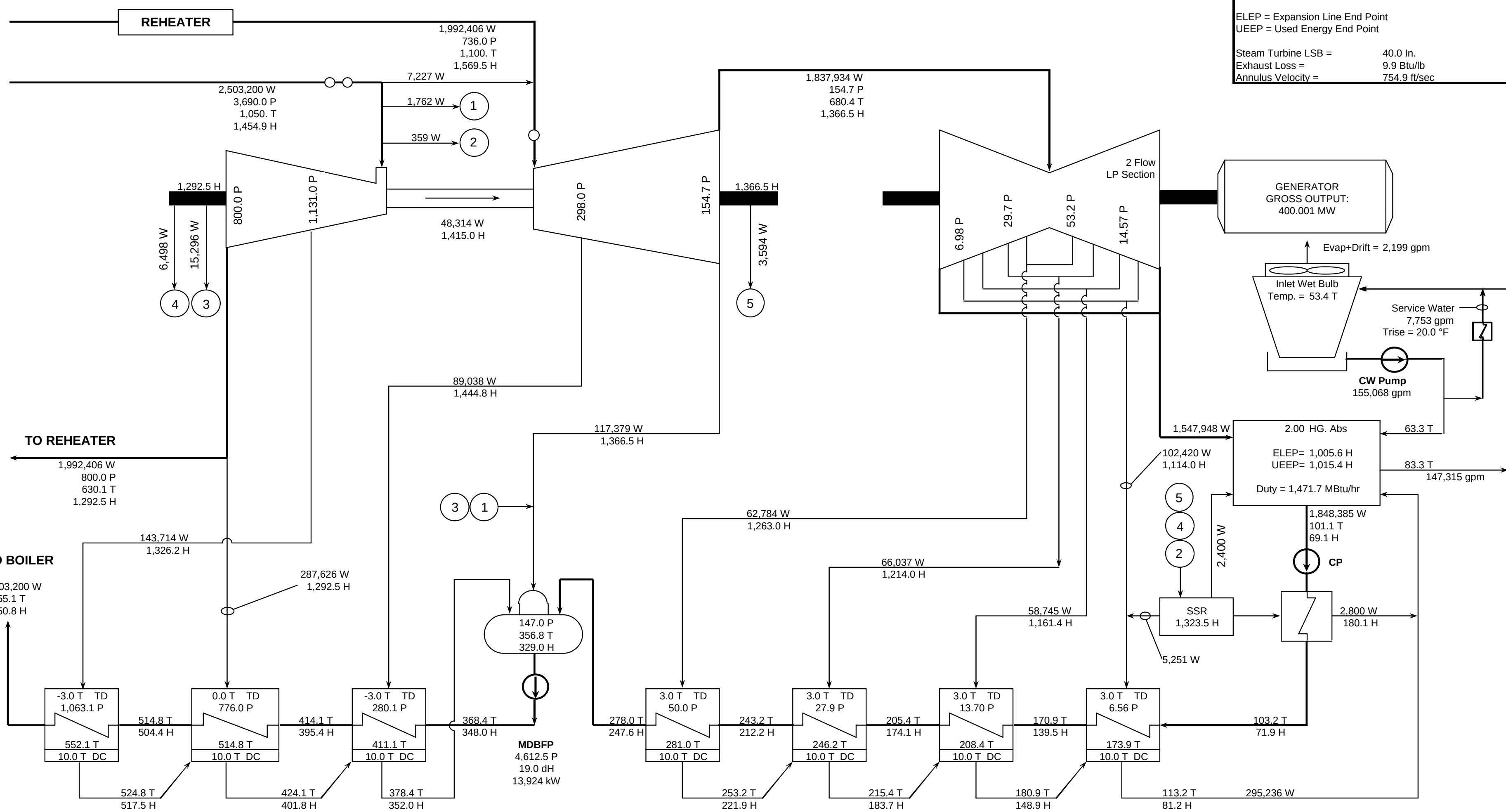
Rev.	Date	Prepared	Reviewed	Approved	Purpose	Project No.:
0	19-Nov-08	L.Papadopoulos			Original Issue	12301-003
						GateCycle Model/Case

PQA STUDY
Subcritical
900 MW
2534.7 P / 1050 T / 1050 T

Note:
Expected Plant Performance, Not Guaranteed.
Calculation based 1997 ASME Steam Table

ELEP = Expansion Line End Point
UEEP = Used Energy End Point

Steam Turbine LSB =	40.0 In.
Exhaust Loss =	9.9 Btu/lb
Annulus Velocity =	754.9 ft/sec



Ambient Dry Bulb =	59.0 T
Ambient Wet Bulb =	51.4 T
Relative Humidity =	60.0%
Site Elevation (AMSL) =	1 ft
Steam Turbine Gross =	400.0 MW

Gross Turbine Heat Rate = Heat Input / Generator Output **= 7,038 Btu/kWh**

Net Turbine Heat Rate = Heat Input / (Generator Output - Power to Motor) **= 7,291 Btu/kWh**

PRELIMINARY
For Information Only

Legend:
W= Flow, lb/hr
P= Pressure, Psia
T= Temperature, °F
H= Enthalpy, Btu/lb

Drawing Release Record

Rev.	Date	Prepared	Reviewed	Approved	Purpose	Project No.:
0	11/19/2008	L.Papadopoulos			Feasibility Study	12301-003
						GateCycle Model/Case

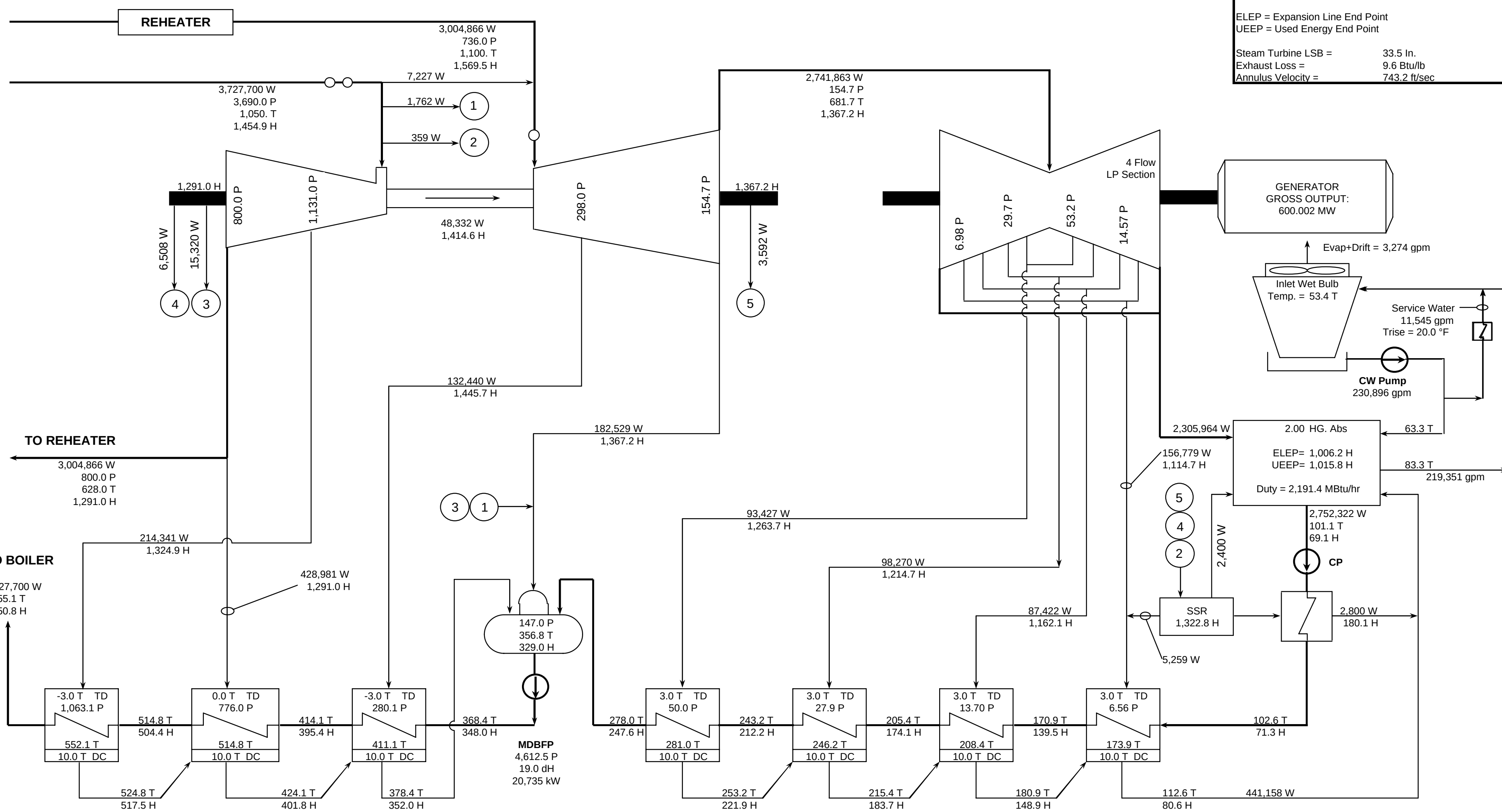
PQA STUDY
SUPERCRITICAL
400 MW
3690 P / 1050 T / 1100 T

Sargent & Lundy LLC

Note:
Expected Plant Performance, Not Guaranteed.
Calculation based 1997 ASME Steam Table

ELEP = Expansion Line End Point
UEEP = Used Energy End Point

Steam Turbine LSB =	33.5 In.
Exhaust Loss =	9.6 Btu/lb
Annulus Velocity =	743.2 ft/sec



Ambient Dry Bulb =	59.0 T
Ambient Wet Bulb =	51.4 T
Relative Humidity =	60.0%
Site Elevation (AMSL) =	1 ft
Steam Turbine Gross =	600.0 MW

Gross Turbine Heat Rate = Heat Input / Generator Output **= 7,011 Btu/kWh**

Net Turbine Heat Rate = Heat Input / (Generator Output - Power to Motor) **= 7,262 Btu/kWh**

PRELIMINARY
For Information Only

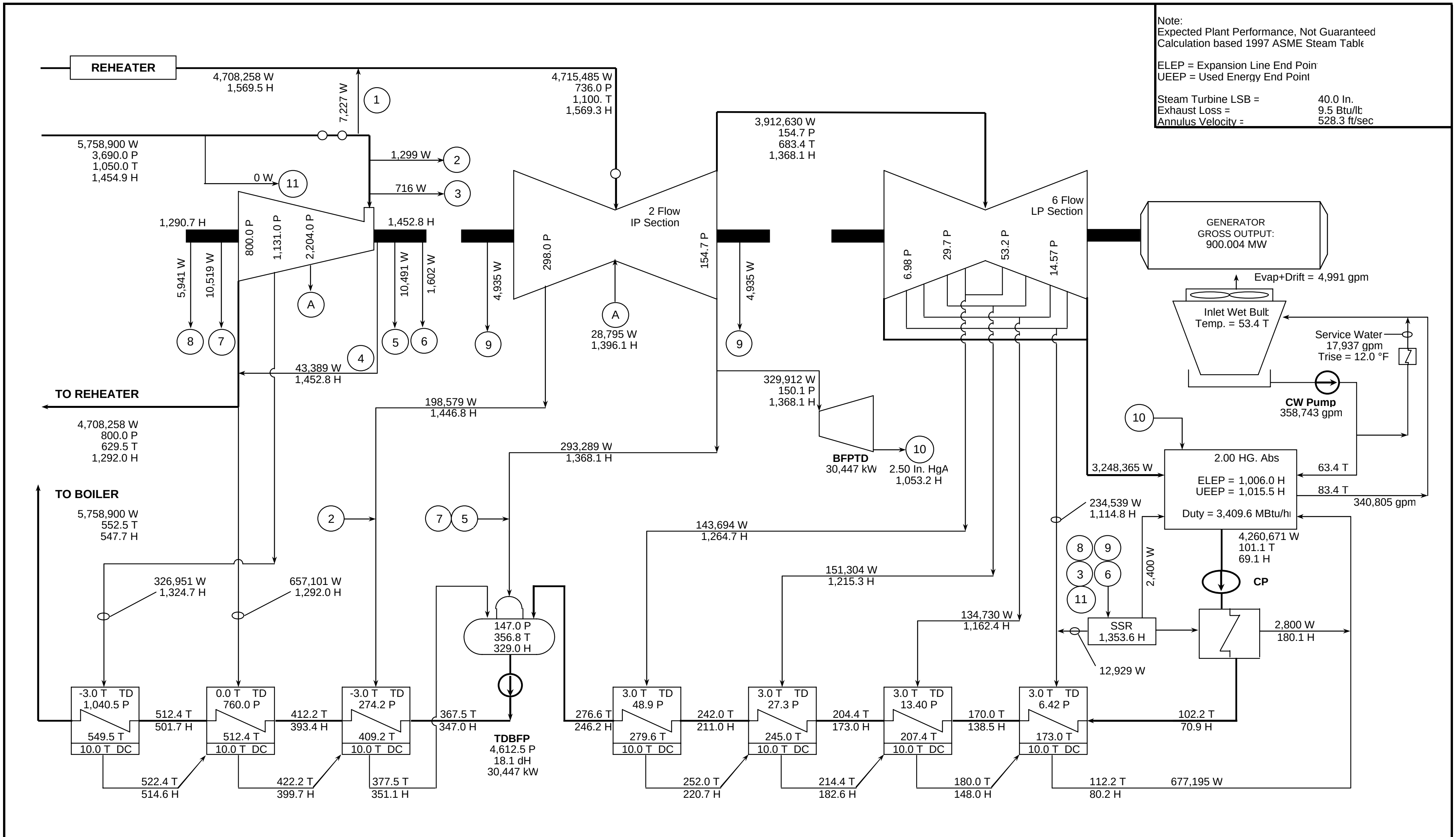
Legend:
W= Flow, lb/hr
P= Pressure, Psia
T= Temperature, °F
H= Enthalpy, Btu/lb

Drawing Release Record

Rev.	Date	Prepared	Reviewed	Approved	Purpose	Project No.:
0	11/19/2008	L.Papadopoulos			Feasibility Study	12301-003
						GateCycle Model/Case

POA STUDY
SUPERCRITICAL
600 MW
3690 P / 1050 T / 1100 T

Sargent & Lundy LLC



Ambient Dry Bulb =	59.0 T
Ambient Wet Bulb =	51.4 T
Relative Humidity =	60.1%
Site Elevation (AMSL) =	1 ft
Steam Turbine Gross =	900.0 MW

Gross Turbine Heat Rate = Heat Input / (Generator Output + Aux. Turbine Outpu = 7,019 Btu/kWh

Net Turbine Heat Rate = Heat Input / Generator Outpu = 7,256 Btu/kWh

Legend:		
W=	Flow	Lb/h
P=	Pressure	Psia
T=	Temp.	°F
H=	Enthalpy	Btu/Lb

Drawing Release Record

Rev.	Date	Prepared	Reviewed	Approved	Purpose	Project No.:
0	19-Nov-08	L.Papadopoulos			Original Issue	12301-003
						GateCycle Model/Case

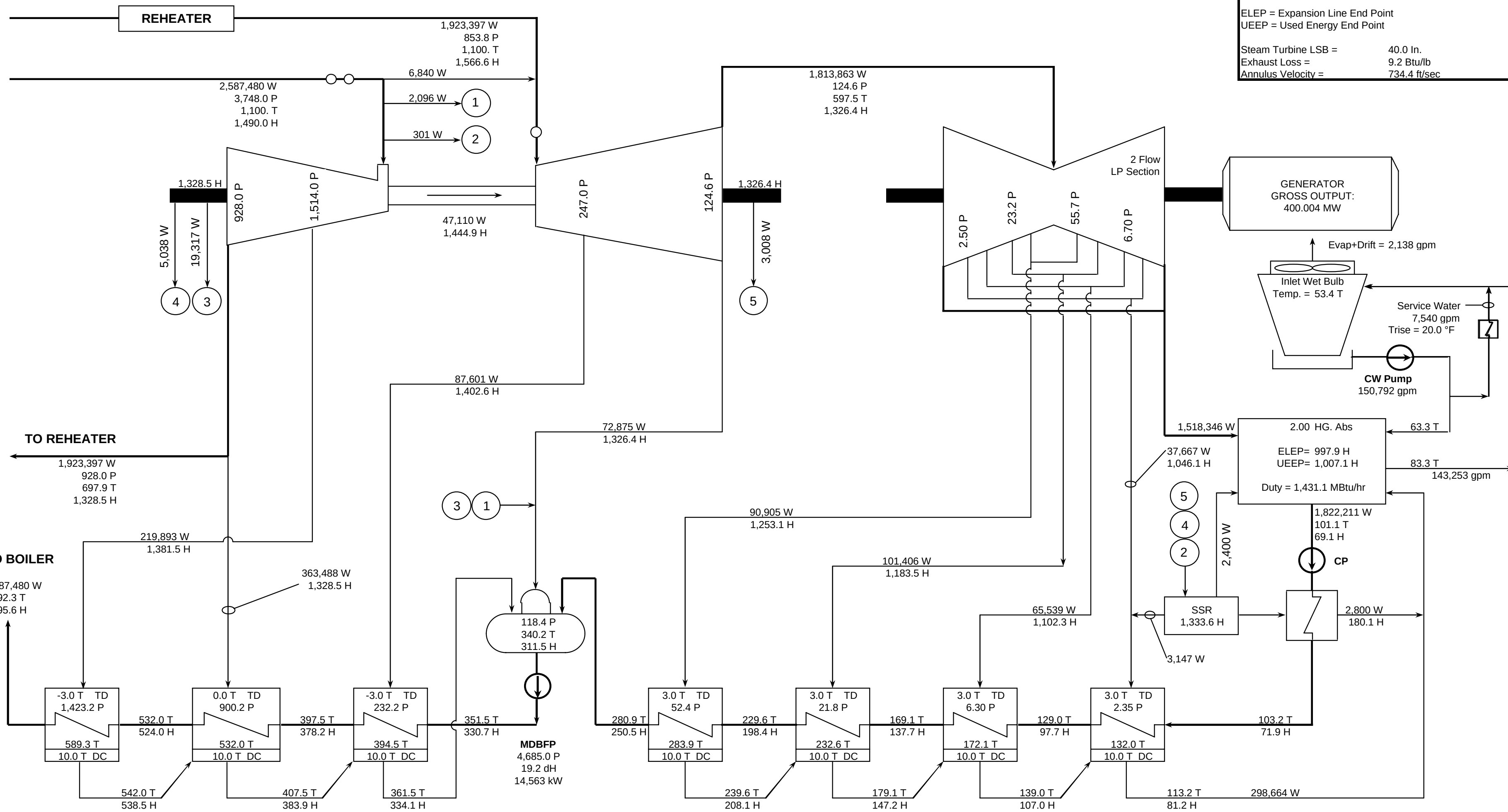
PQA STUDY
Supercritical
900 MW
3690 P / 1050 T / 1100 T

Sargent & Lundy LLC

Note:
Expected Plant Performance, Not Guaranteed.
Calculation based 1997 ASME Steam Table

ELEP = Expansion Line End Point
UEEP = Used Energy End Point

Steam Turbine LSB =	40.0 In.
Exhaust Loss =	9.2 Btu/lb
Annulus Velocity =	734.4 ft/sec



Gross Turbine Heat Rate = Heat Input / Generator Output **= 6,931 Btu/kWh**

Net Turbine Heat Rate = Heat Input / (Generator Output - Power to Motor) **= 7,193 Btu/kWh**

PRELIMINARY
For Information Only

Ambient Dry Bulb =	59.0 T
Ambient Wet Bulb =	51.4 T
Relative Humidity =	60.0%
Site Elevation (AMSL) =	1 ft
Steam Turbine Gross =	400.0 MW

Legend:

W=	Flow, lb/hr
P=	Pressure, Psia
T=	Temperature, °F
H=	Enthalpy, Btu/lb

Drawing Release Record

Rev.	Date	Prepared	Reviewed	Approved	Purpose	Project No.:
0	11/18/2008	L.Papadopoulos			Feasibility Study	12301-003
						GateCycle Model/Case

POA STUDY
ULTRA SUPERCRITICAL
400 MW

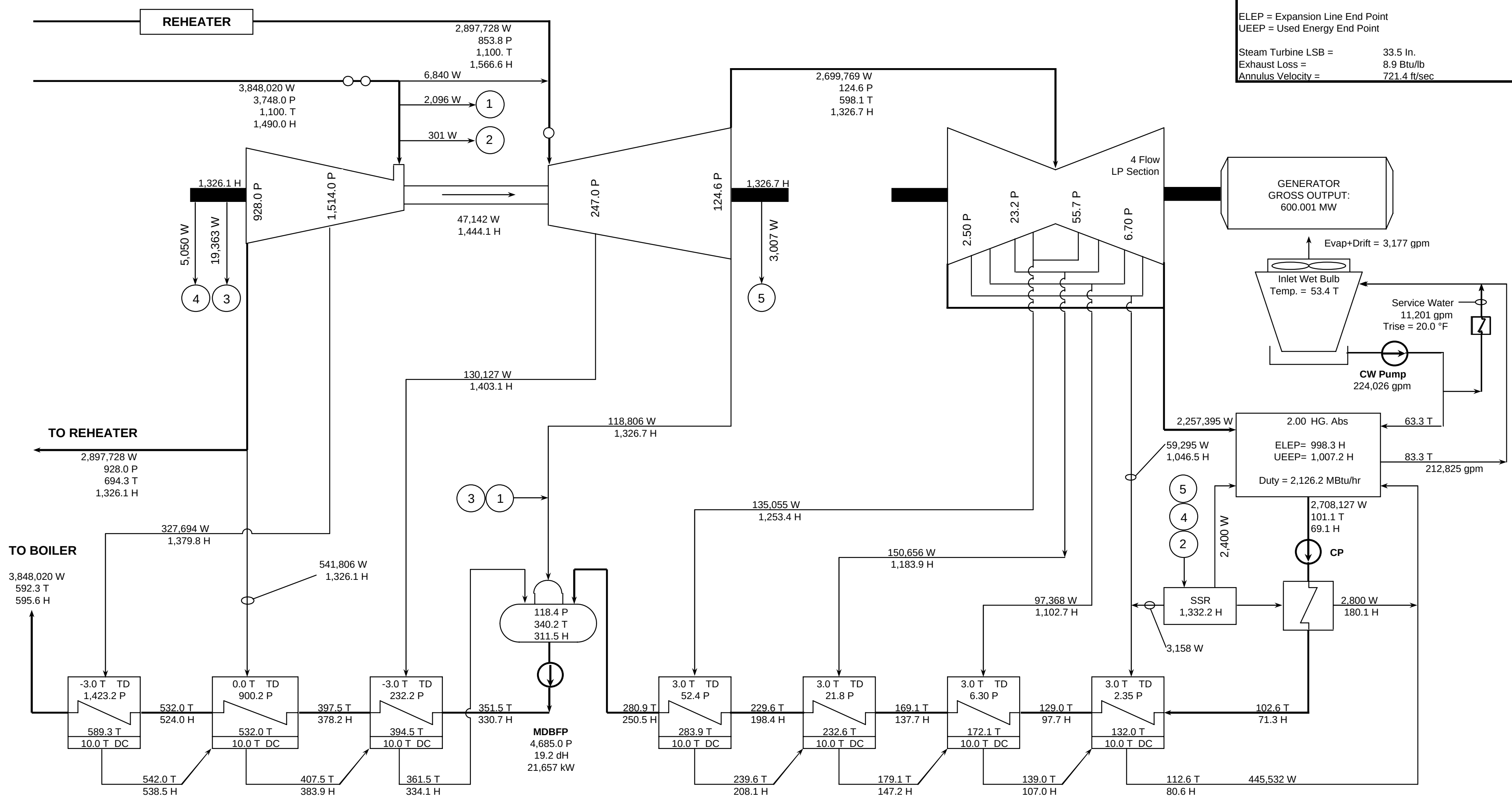
3748 P / 1100 T / 1100 T

Sargent & Lundy LLC

Note:
Expected Plant Performance, Not Guaranteed.
Calculation based 1997 ASME Steam Table

ELEP = Expansion Line End Point
UEEP = Used Energy End Point

Steam Turbine LSB =	33.5 In.
Exhaust Loss =	8.9 Btu/lb
Annulus Velocity =	721.4 ft/sec



Ambient Dry Bulb =	59.0 T
Ambient Wet Bulb =	51.4 T
Relative Humidity =	60.0%
Site Elevation (AMSL) =	1 ft
Steam Turbine Gross =	600.0 MW

Gross Turbine Heat Rate = Heat Input / Generator Output **= 6,898 Btu/kWh**

Net Turbine Heat Rate = Heat Input / (Generator Output - Power to Motor) **= 7,156 Btu/kWh**

PRELIMINARY
For Information Only

Legend:
- W= Flow, lb/hr
- P= Pressure, Psia
- T= Temperature, °F
- H= Enthalpy, Btu/lb

Drawing Release Record

Rev.	Date	Prepared	Reviewed	Approved	Purpose	Project No.:
0	11/18/2008	L.Papadopoulos			Feasibility Study	12301-003
						GateCycle Model/Case

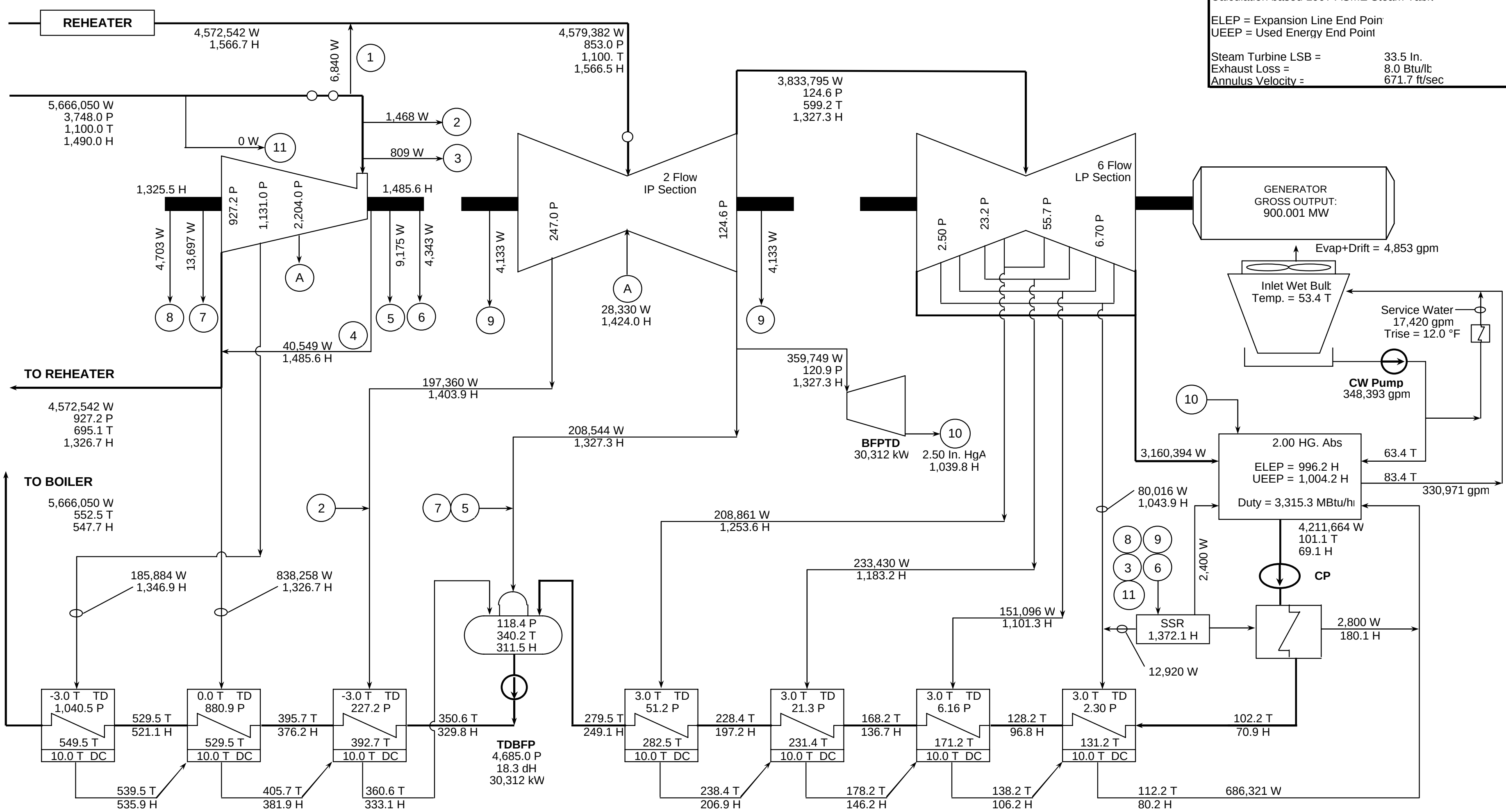
PQA STUDY
ULTRA SUPERCRITICAL
600 MW
3748 P / 1100 T / 1100 T

Sargent & Lundy LLC

Note:
Expected Plant Performance, Not Guaranteed
Calculation based 1997 ASME Steam Table

ELEP = Expansion Line End Point
UEEP = Used Energy End Point

Steam Turbine LSB =	33.5 In.
Exhaust Loss =	8.0 Btu/lb
Annulus Velocity =	671.7 ft/sec



Gross Turbine Heat Rate = Heat Input / (Generator Output + Aux. Turbine Outpu = 6,919 Btu/kWh

Net Turbine Heat Rate = Heat Input / Generator Outpu = 7,152 Btu/kWh

Ambient Dry Bulb =	59.0 T
Ambient Wet Bulb =	51.4 T
Relative Humidity =	60.1%
Site Elevation (AMSL) =	1 ft
Steam Turbine Gross =	900.0 MW

Legend:

W=	Flow	Lb/h
P=	Pressure	Psia
T=	Temp.	°F
H=	Enthalpy	Btu/Lb

Drawing Release Record

Rev.	Date	Prepared	Reviewed	Approved	Purpose	Project No.:
0	19-Nov-08	L.Papadopoulos			Original Issue	12301-003
						GateCycle Model/Case

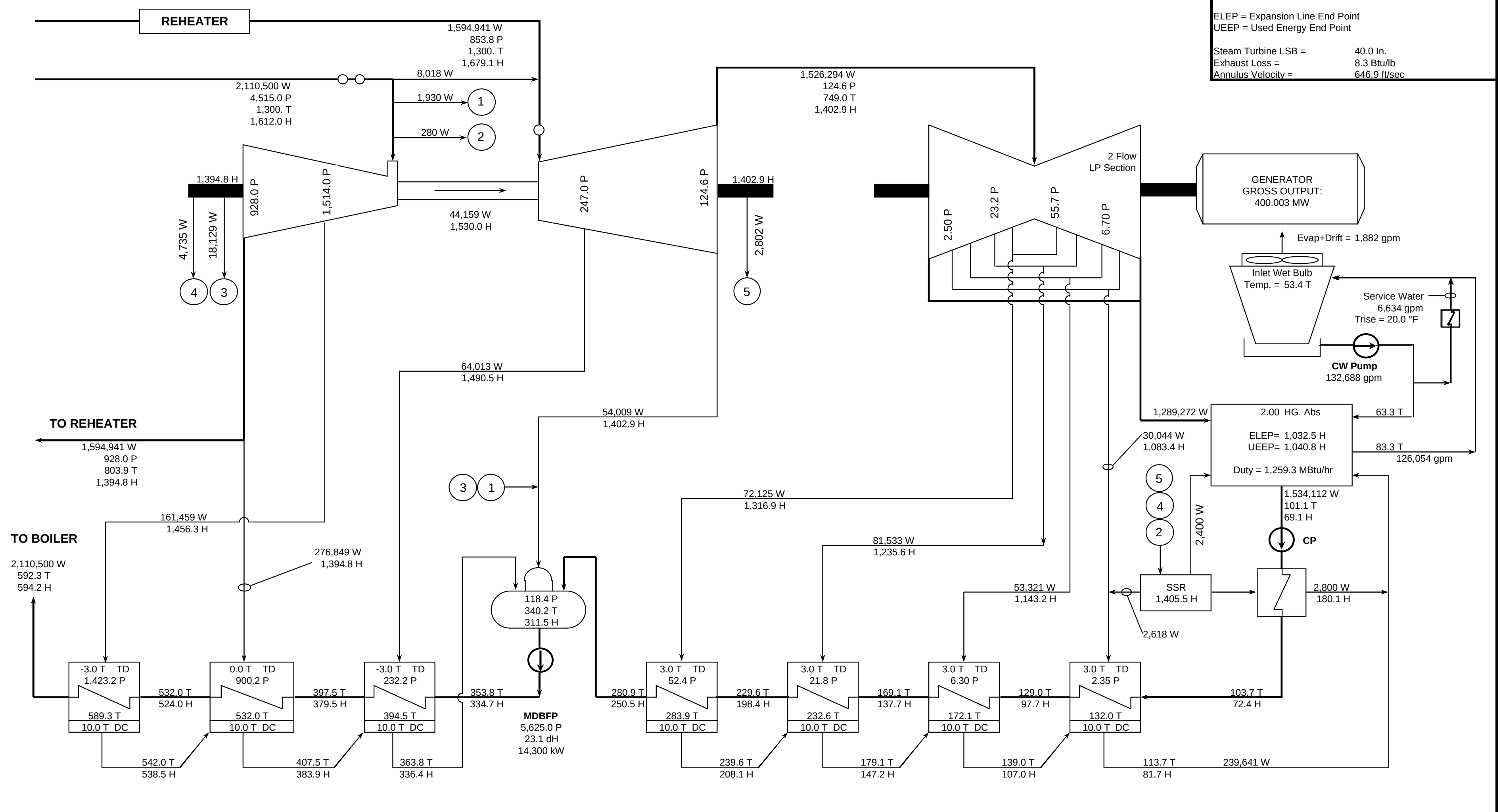
PQA STUDY
Ultra-Supercritical
900 MW
3748 P / 1100 T / 1100 T

Sargent & Lundy LLC

Note:
Expected Plant Performance, Not Guaranteed.
Calculation based 1997 ASME Steam Table

ELEP = Expansion Line End Point
UEEP = Used Energy End Point

Steam Turbine LSB =	40.0 In.
Exhaust Loss =	8.3 Btu/lb
Annulus Velocity =	646.9 ft/sec



Ambient Dry Bulb =	59.0 T
Ambient Wet Bulb =	51.4 T
Relative Humidity =	60.0%
Site Elevation (AMSL) =	1 ft
Steam Turbine Gross =	400.0 MW

Gross Turbine Heat Rate = Heat Input / Generator Output **= 6,504 Btu/kWh**

Net Turbine Heat Rate = Heat Input / (Generator Output - Power to Motor) **= 6,745 Btu/kWh**

PRELIMINARY
For Information Only

Legend:
W= Flow, lb/hr
P= Pressure, Psia
T= Temperature, °F
H= Enthalpy, Btu/lb

Drawing Release Record

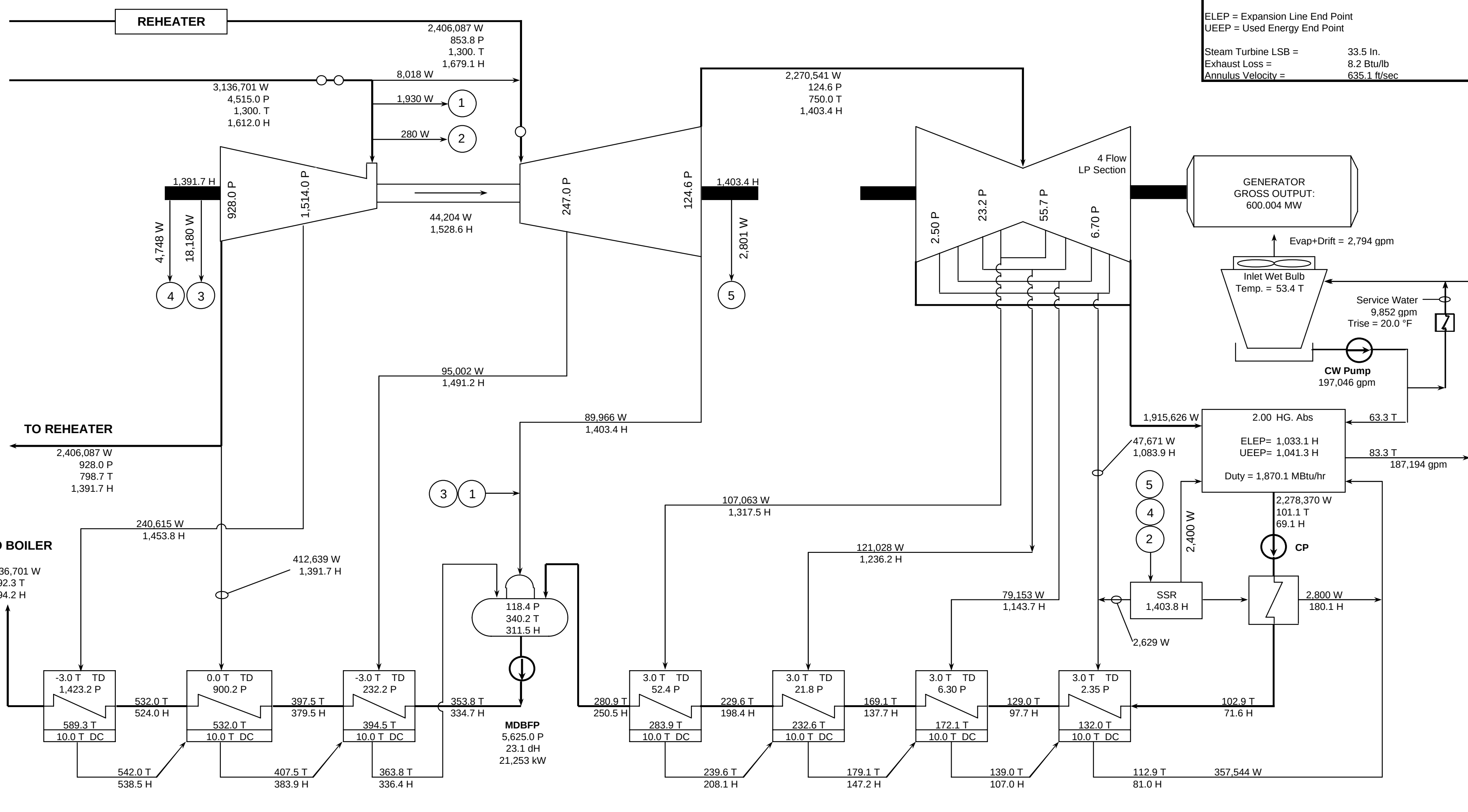
Rev.	Date	Prepared	Reviewed	Approved	Purpose	Project No.:
0	11/19/2008	L.Papadopoulos			Feasibility Study	12301-003
						GateCycle Model/Case

POA STUDY
ADVANCED SUPERCRITICAL
400 MW
4515 P / 1300 T / 1300 T

Note:
Expected Plant Performance, Not Guaranteed.
Calculation based 1997 ASME Steam Table

ELEP = Expansion Line End Point
UEEP = Used Energy End Point

Steam Turbine LSB =	33.5 In.
Exhaust Loss =	8.2 Btu/lb
Annulus Velocity =	635.1 ft/sec



Gross Turbine Heat Rate = Heat Input / Generator Output = 6,474 Btu/kWh

Net Turbine Heat Rate = Heat Input / (Generator Output - Power to Motor) = 6,712 Btu/kWh

PRELIMINARY
For Information Only

Ambient Dry Bulb =	59.0 T
Ambient Wet Bulb =	51.4 T
Relative Humidity =	60.0%
Site Elevation (AMSL) =	1 ft
Steam Turbine Gross =	600.0 MW

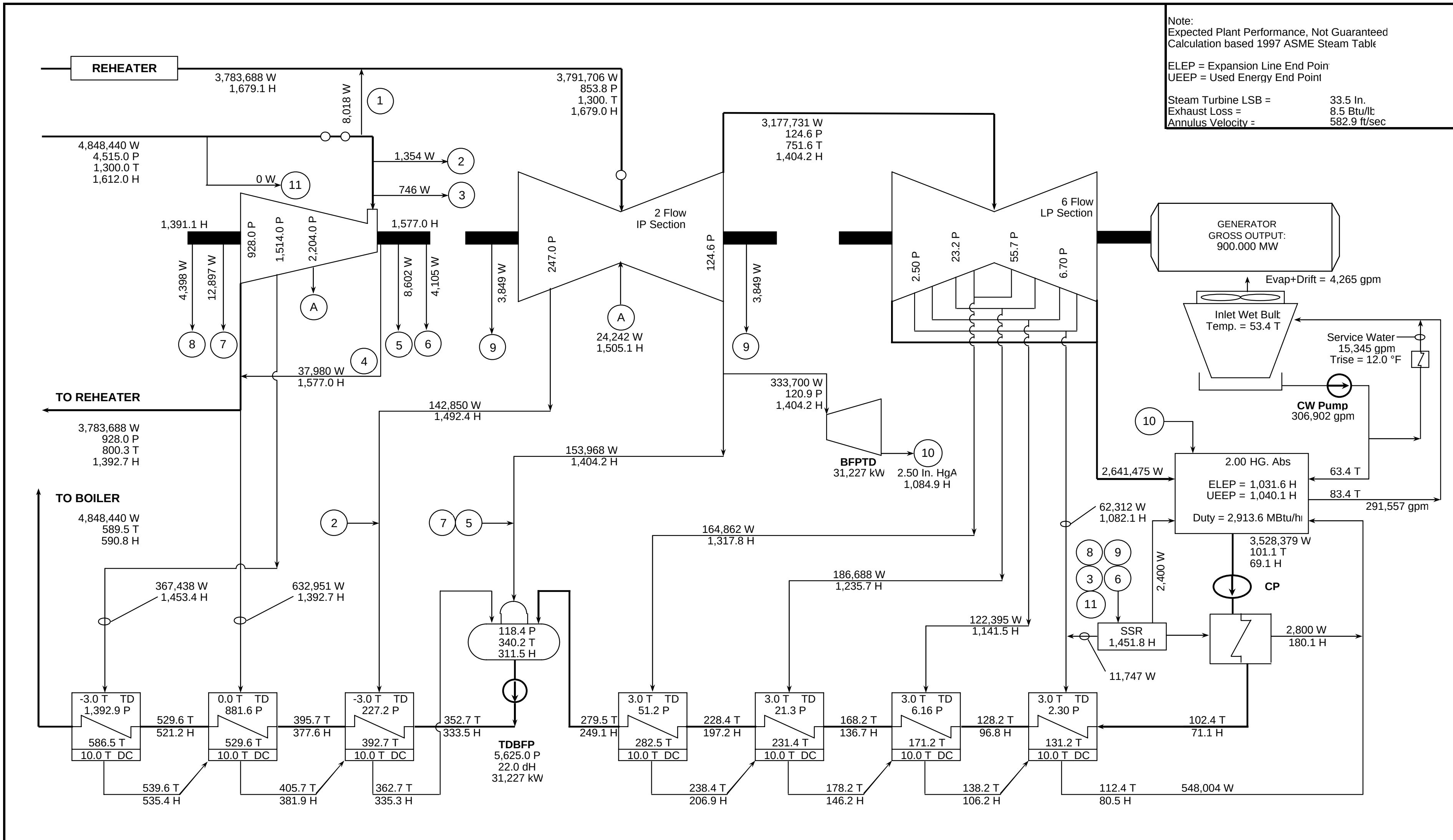
Legend:
W= Flow, lb/hr
P= Pressure, Psia
T= Temperature, °F
H= Enthalpy, Btu/lb

Drawing Release Record

Rev.	Date	Prepared	Reviewed	Approved	Purpose	Project No.:
0	11/19/2008	L.Papadopoulos			Feasibility Study	12301-003
						GateCycle Model/Case

PQA STUDY
ADVANCED SUPERCRITICAL
600 MW
4515 P / 1300 T / 1300 T

Sargent & Lundy LLC



Ambient Dry Bulb =	59.0 T
Ambient Wet Bulb =	51.4 T
Relative Humidity =	60.1%
Site Elevation (AMSL) =	1 ft
Steam Turbine Gross =	900.0 MW

Gross Turbine Heat Rate = Heat Input / (Generator Output + Aux. Turbine Outpu = 6,481 Btu/kWh

Net Turbine Heat Rate = Heat Input / Generator Outpu = 6,706 Btu/kWh

Legend:		
W=	Flow	Lb/h
P=	Pressure	Psia
T=	Temp.	°F
H=	Enthalpy	Btu/Lb

Drawing Release Record

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0	19-Nov-08	L.Papadopoulos			Original Issue	12301-003
						GateCycle Model/Case

PQA STUDY
Advanced-Supercritical
900 MW
4515 P / 1300 T / 1300 T

Sargent & Lundy LLC

APPENDIX D

PC POWER PLANT HEAT BALANCE CALCULATION DETAILS

NET TURBINE HEAT RATE

Estimating net turbine heat rate was based on the assumptions described below.

1. Steam Turbine Predicted Performance

Steam turbine performance is reported as heat rate (Btu/kWh). This is a measure of the thermal heat energy provided to the steam cycle and the generated electrical output. Heat rate is related to the overall steam cycle efficiency.

The most common method of predicting steam turbine performance is the Spencer Cotton Cannon (SCC) method. This method, developed by General Electric and published in the 1960s, is used in most commercially available heat balance programs. However, due to modern steam turbine improvements in blade design and configurations for intermediate-pressure (IP) and low-pressure (LP) sections, the turbine section efficiencies are about 2% better than what would be predicted by SCC. This has been confirmed by comparing predicted performance to performance received from steam turbine manufacturers.

The high-pressure (HP) steam turbine design condition is at the operating condition corresponding to the maximum inlet steam flow rate with the maximum pressure and temperature. At this condition, it is assumed that the control valve is in the valve-wide-open position, thus establishing a throttle flow ratio of 1.0.

A 2.0% pressure drop is accounted for across the control valve at the inlet to the turbine. For opposed-flow HP-IP turbine sections, the heat balance calculation accounts for the shaft/seal leakage that occurs from the HP to the IP steam turbine. This leakage is approximated at 2.2% of the main steam flow rate into the turbine. It is assumed that it exits the HP section just before the governing stage and mixes with the hot reheat steam flow entering the IP steam turbine. The HP steam turbine discharge pressure generally is 20-25% of the steam pressure entering the turbine.

For the LP section, additional losses must be accounted for due to steam exhausting from the turbine into the condenser. These losses are primarily due to turbulent flow and directional changes when exiting the turbine. These losses are calculated using the "exhaust loss curve," which is unique for different last-stage blade lengths and LP frame sizes.

Using manufacturer-developed exhaust loss curves, the LP section last-stage blade length and related annulus area are analyzed with the purpose of minimizing the exhaust losses. The SCC method provides the predicted exhaust loss for a given blade length as a function of the exhaust steam velocity. The blade length used in performance analyses is selected to minimize exhaust losses (Btu/lb) and still maintain a reasonable exhaust velocity.

Because the LP turbine exhaust pressure can significantly affect exhaust losses, the condenser pressure is held constant at 2" HgA to provide comparable results between all cases.

2. Generator

The steam turbine generator is modeled with a 0.85 power factor, and a coolant pressure of 74.7 psia. The mechanical and electrical loss is approximated by 1.5-2.0% of the gross generator output.

3. Condensate Pump

The condensate pump discharge pressure is assumed to be 250 psia, with an overall pump efficiency of 85%.

4. Feedwater Heaters

When extraction steam from the steam turbines is used to heat the feedwater, this method of heating the boiler feedwater is known as regenerative feedwater heating. For a typical subcritical design, the cycle is designed with four LP and two HP feedwater heaters, with a direct-contact deaerating feedwater heater for seven stages of feedwater heating. For a supercritical and ultra-supercritical cycle, a HARP (heater above reheat point) feedwater heater is added to the cycle. These are established feedwater heater arrangements that have proven to be economically beneficial.

5. Boiler Feedwater Pump

For units operating below 650 MW, motor-driven boiler feed pumps are preferred. The boiler feedwater pump discharge pressure typically is designed as 125% of the main steam pressure into the HP turbine, and with a pump efficiency of 85%. For motor-driven feedwater pumps the motor efficiency of 95% is also included.

6. Boiler Feed Pump Turbine Drive

For units operating above 650 MW, a boiler feed pump turbine drive is normally selected. The usual steam source for these turbine drives is from IP extraction steam at normal unit loads, and main steam at low-unit loads and bypass cases. The boiler feed pump turbine drive exhaust pressure is assumed as 0.5 in.Hg Abs. greater than the condenser operating pressure. The turbine drive efficiency is calculated using the SCC method.

7. System Pressure Drops

The pressure drop characteristics of each pipeline, at the design condition, are listed in the following table:

	Pressure Drop
Reheat system	8.0% ultra-supercritical 8.0% supercritical 10.0% subcritical
Extraction line	5.0%
Turbine flange	3.0%
BFP turbine drive	3.0%

8. Turbine Heat Rates

Turbine heat rate is a measure of steam turbine efficiency as defined by the following equation:

(Note that the definition of gross turbine heat rate and net turbine heat rate depends on whether the boiler feed pump is motor driven or turbine driven.)

$$\text{Heat Rate [Btu/kWh]} = \frac{\text{Heat added to turbine cycle [Btu / hr]}}{\text{Generator Output[kW]}}$$

$$\text{Heat Input} = Q_T(H_T - H_{FW}) + Q_{Rhtr}(H_{HRH} - H_{CRH})$$

Where: Q_T = Throttle flow [lb/hr]

Q_{Rhtr} = Reheater flow [lb/hr]

H_T = Throttle enthalpy [BTU/lb]

H_{FW} = Final feedwater enthalpy [BTU/lb]

H_{HRH} = Enthalpy leaving reheater [BTU/lb]

H_{CRH} = Enthalpy entering reheater [BTU/lb]

For cycles with motor driven boiler feed pump:

$$\text{Gross turbine heat rate [Btu/kWh]} = \frac{\text{Heat Input [Btu / hr]}}{\text{Generator Output[kW]}}$$

$$\text{Net turbine heat rate [Btu/kWh]} = \frac{\text{Heat Input [Btu / hr]}}{\text{Generator Output[kW]} - \text{Power to Motor [kW]}}$$

For cycles with steam driven boiler feed pump:

$$\text{Gross turbine heat rate [Btu/kWh]} = \frac{\text{Heat Input [Btu / hr]}}{\text{Generator Output[kW]} + \text{Auxiliary Turbine Output[kW]}}$$

$$\text{Net turbine heat rate [Btu/kWh]} = \frac{\text{Heat Input [Btu / hr]}}{\text{Generator Output[kW]}}$$

The net turbine heat rate is used to estimate the net unit heat rate by correcting it for boiler efficiency and auxiliary power.

BOILER EFFICIENCY

The boiler efficiency is estimated according to ASME guidelines. The inputs required for the boiler efficiency estimation include the following:

- Coal composition
- Ambient air temperature, humidity
- Excess air
- Uncorrected air heater outlet temperature

This information is used to calculate the following losses associated with un-recovered heat from the burned fuel:

- Radiation losses
- Sensible heat with dry flue gas
- Latent and sensible heat with water vapor from the fuel, moisture in combustion air, and the combustion of hydrogen in fuel
- Carbon loss, assumed as 0.5% for bituminous coal and 0.1% for PRB and lignite
- Unaccounted losses, 0.5% for all fuels
- Manufacturer's margin, 0.2% for all fuels

The air heater outlet temperature was estimated based on the sulfuric acid dew point. The sulfuric acid dew point was calculated for all three coals with estimated SO_3 concentrations at the air heater outlet. A 20°F margin was added to the acid dew point, which is a typical practice in the industry to eliminate the possibility of sulfuric acid condensation at the cold end of air heater and the downstream equipment.

AUXILIARY POWER ESTIMATION

The auxiliary power included the following categories:

- Condensate pumps
- Circulating water pumps
- Cooling towers
- Forced draft (FD) fan
- Induced draft (ID) fan
- Primary air (PA) fan
- Pulverizers
- Fuel handling
- Ash handling
- Baghouse
- Wet FGD for bituminous coal and lignite, dry FGD for PRB, wet ESP for bituminous coal
- Transformer losses
- Miscellaneous, 1% margin for all fuels

The pressure drop for the total system was estimated for FD and ID fans.

NET UNIT HEAT RATE

Net unit heat rate (NUHR) is a measure of overall plant efficiency and accounts for steam turbine efficiency, boiler efficiency, and auxiliary power demands.

$$\text{NUHR [Btu/kWh]} = \frac{\text{Net Turbine Heat Rate [Btu/kW h]}}{\text{Boiler Efficiency[\%]} / 100 \times (1 - (\text{Auxiliary Power} / 100[\%]))}$$

Plant Efficiency:

$$\text{Plant Efficiency [\%]} = \frac{3412 \text{ [Btu/kWh]}}{\text{NUHR [Btu/kWh]}} \times 100$$

APPENDIX E

SC AND IGCC POWER PLANT PERFORMANCE AND COST ESTIMATE SPREADSHEETS

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Number of BFW Heaters		**8 (HARP)**	**8 (HARP)**	**8 (HARP)**	**NA**	**NA**	**NA**
Number of FGD Absorbers		**1**	**1**	**2**	**2 AGR**	**2 AGR**	**2 AGR**
Number of wet ESPs		**2**	**0**	**0**	**2 CYC/CFLT/SCRB**	**2 CYC/CFLT/SCRB**	**2 CYC/CFLT/SCRB**
Number of Pulverizers		**6**	**7**	**6**	**5**	**9**	**6**
SO2		**Wet FGD**	**Wet FGD**	**Dry FGD**	**Sulfinol**	**Sulfinol**	**Sulfinol**
NOX		**High Dust SCR**	**High Dust SCR**	**High Dust SCR**	**SCR**	**SCR**	**SCR**
Primary Particulate Control		**Baghouse**	**Baghouse**	**Baghouse**	**Cyclone/Candle Filter**	**Cyclone/Candle Filter**	**Cyclone/Candle Filter**
Secondary Particulate Control		**Wet ESP**	**None**	**None**	**Wet Scrubber**	**Wet Scrubber**	**Wet Scrubber**
Mercury Control		**Inherent**	**ACI-w/BGH**	**ACI-w/BGH**	**Carbon - Packed Bed**	**Carbon - Packed Bed**	**Carbon - Packed Bed**
PLANT CONFIGURATION: (Gross-MW)		**1x685**	**1x685**	**1x685**	**1x728**	**1x711**	**1x727**
NO. OF STEAM GENERATORS		1 Boiler	1 Boiler	1 Boiler	2 SGC/HRSG	2 SGC/HRSG	2 SGC/HRSG
Main Steam Pressure	psig	3690	3690	3690	1800	1800	1800
Main Steam Temperature	°F	1050	1050	1050	1000	1000	1000
Hot Reheat Temperature	°F	1100	1100	1100	1000	1000	1000
NO. OF STEAM TURBINES		1 STG	1 STG	1 STG	1 STG	1 STG	1 STG
NO. OF COMBUSTION TURBINES		N/A	N/A	N/A	2 CTG	2 CTG	2 CTG
SOx CONTROL:		Wet FGD	Wet FGD	Dry FGD	Sulfinol	Sulfinol	Sulfinol
Uncontrolled SO2 Emission Rate	lb/mmBtu	4.32	2.14	0.52	4.32	2.14	0.52
Target "Permit" SO_2 Emission Rate	lb/mmBtu	0.10	0.08	0.08	0.02	0.02	0.02
SULFUR REMOVAL percent required meet Target "Permit" Rate	%	97.68	96.27	84.76	99.54	99.07	96.19
Typical Maximum SO2 Removal Guarantee from Vendor	%	98.15	97.20	88.57	99.77	99.53	98.10
NOx CONTROL:		SCR	SCR	SCR	SCR	SCR	SCR
Uncontrolled Rate from Boiler/CTG	lb/mmBtu	0.25	0.20	0.20	0.048	0.050	0.048
Target "Permit" NOx Emission Rate	lb/mmBtu	0.07	0.07	0.07	0.022	0.022	0.022
PARTICULATE CONTROL		Baghouse	Baghouse	Baghouse	2 CYC/CFLT/SCRB	2 CYC/CFLT/SCRB	2 CYC/CFLT/SCRB
Target "Permit" Emission Rate	lb/mmBtu	0.015	0.015	0.015	0.015	0.015	0.015
Specified Design Guarantee from vendor	lb/mmBtu	0.012	0.012	0.012	0.007	0.007	0.007
Mercury Control		Inherent	ACI-w/BGH	ACI-w/BGH	Carbon - Packed Bed	Carbon - Packed Bed	Carbon - Packed Bed
Cooling Method		MD-CT	MD-CT	MD-CT	MD-CT	MD-CT	MD-CT
PLANT PERFORMANCE:						0.162418206	
Net Plant Heat Rate, HHV	Btu/net-kWh	9,000	9,584	9,063	8,425	8,515	8,062
Gross Plant Output	**Gross-kW**	**685,000**	**685,000**	**685,000**	**726,061**	**711,238**	**726,824**
Net Plant Output (based on Annual Average Conditions)	Net-kW	609,083	603,868	616,041	610,232	595,720	612,365
Gross Plant Heat Rate, HHV	Btu/gross-kWh	8,002	8,449	8,151	7,081	7,132	6,792
Auxiliary Power	kW	75,917	81,132	68,959	115,829	115,518	114,459
Turbine Heat Rate	Btu/kWh	7,005	7,005	7,005	NA	NA	NA
Primary Fuel Feed Rate per Boiler/Gasifi	lb/hr	471,271	969,784	666,118	221,000	425,000	294,500
Primary Fuel Feed Rate per Boiler/Gasifie	Tons/hr	236	485	333	111	213	147
Primary Fuel Feed Rate per Boiler/Gasifi	lb/net-MWh	774	1,606	1,081	362	713	481
Full load Heat input to Boiler/Gasifier	mmBtu's/hr	5,481	5,788	5,583	2,571	2,536	2,468
Secondary Fuel Feed Rate	lb/hr	N/A	N/A	N/A	N/A	N/A	N/A
Limestone Feed Rate	lb/net-MWh				N/A	N/A	N/A
Lime/Limestone Feed Rate	lb/hr	41,521	21,576	3,134	N/A	N/A	N/A
Lime/Limestone Feed Rate	lb/net-MWh	68.2	35.7	5.1	N/A	N/A	N/A
Ammonia Feed Rate(Anhydrous)	lb/hr	325	343	331	111	111	111
Ammonia Feed Rate	lb/net-MWh	0.534	0.568	0.537	0.182	0.186	0.181
Activated Carbon Injection Rate	lb/hr	0	202	184	NA	NA	NA
Activated Carbon Injection Rate	lb/net-MWh	0.00	0.33	0.30	NA	NA	NA

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Water Consumption							
Cycle Make-up & Misc. Services	gpm	931	931	931	1,010	910	984
Cooling Tower/lake make-up	gpm	7,309	7,246	7,392	3,866	3,716	3,745
Total Water	gpm	8,240	8,177	8,323	4,876	4,626	4,729
Water Consumption	gal/net-MWh	812	812	811	479	466	463
FUEL ANALYSIS:		Bituminous	Lignite	PRB	Bituminous	Lignite	PRB
Ultimate Analysis							
Carbon	%	63.75	36.27	50.25	63.75	36.27	50.25
Sulfur	**%**	**2.51**	**0.64**	**0.22**	**2.51**	**0.64**	**0.22**
Oxygen	%	6.88	10.76	13.55	6.88	10.76	13.55
Hydrogen	%	4.50	2.42	3.41	4.50	2.42	3.41
Nitrogen	%	1.25	0.71	0.65	1.25	0.71	0.65
Chlorine	%	0.29	0.00	0.00	0.29	0.00	0.00
Ash	%	9.70	17.92	4.50	9.70	17.92	4.50
Moisture	%	11.12	31.24	27.40	11.12	31.24	27.40
Proximate Analysis							
Moisture	%	11.12	31.24	27.40	11.12	31.24	27.40
Volatile matter	%	34.99			34.99		
Fixed Carbon	%	44.19			44.19		
Ash	%	9.70	17.92	4.50	9.70	17.92	4.50
Gross Higher Heating Value (Dulong)	Btu/lb	11,631	5,968	8,382	11,631	5,968	8,382
SORBENT ANALYSIS:							
CaCO3	%	90	90	0	NA	NA	NA
MgCO3	%	5	5	0	NA	NA	NA
CaO	%	0	0	90	NA	NA	NA
Ash/Inerts	%	5	5	10	NA	NA	NA
Moisture	%	0	0	0	NA	NA	NA
STEAM GENERATOR DATA (Per Boiler):							
Theoretical Air	lb/lb-fuel	8.70	4.57	6.39	NA	NA	NA
Theoretical Dry Gas	lb/lb-fuel	9.09	4.87	6.76	NA	NA	NA
Actual Dry Gas	lb/lb-fuel	10.83	5.78	8.04	NA	NA	NA
Excess Air	%	20	20	20	NA	NA	NA
Total Dry Air Flow	lb/lb-fuel	10.45	5.49	7.67	NA	NA	NA
Ambient Air Moisture	lb/lb-lair	0.025	0.025	0.025	NA	NA	NA
Total Air Flow	lb/lb-fuel	10.71	5.63	7.86	NA	NA	NA
Flue Gas Moisture Flow	lb/lb-fuel	0.774	0.666	0.770	NA	NA	NA
Products of Combustion	lb/lb-fuel	11.61	6.45	8.81	NA	NA	NA
Air Heater Leakage	%	5	5	5	NA	NA	NA
Air Heater Inlet Temperature	°F	100	100	100	NA	NA	NA
Infiltration	%	5	5	5	NA	NA	NA
Exit Flue Gas Temperature	°F	310	305	280	NA	NA	NA
Flue Gas Temp. Uncorrected	°F	319	314	288	NA	NA	NA
Flue Gas Flow Rate (per boiler)	lb/hr	5,932,472	6,752,621	6,349,254	NA	NA	NA
Flue Gas Flow Rate (IGCC coal dry air)	acfm	1,984,022	2,243,644	2,040,678	178,631	329,505	228,328
Combustion Air Flow	lb/hr	5,045,625	5,456,731	5,233,458	NA	NA	NA
Combustion Air Flow	acfm	1,203,590	1,301,655	1,248,396	NA	NA	NA
Stack Flue Gas Temperature	°F	135	140	170	210	210	210
Stack Flue Gas Flow Rate per Flue	acfm	1,623,422	1,863,384	1,875,057	1,214,183	1,214,790	1,214,487
Radiation Loss	%	0.182	0.182	0.182	N/A	N/A	N/A
Dry Gas Heat Loss	%	5.89	5.96	5.19	N/A	N/A	N/A
Fuel Moisture Loss	%	1.07	5.84	3.62	N/A	N/A	N/A
Hydrogen in Fuel Loss	%	3.89	4.07	4.06	N/A	N/A	N/A
Air Moisture Heat Loss	%	0.237	0.236	0.206	N/A	N/A	N/A
Carbon Loss	%	0.50	0.10	0.10	N/A	N/A	N/A
Unaccounted Loss	%	0.20	0.20	0.20	N/A	N/A	N/A
Manufacturer's Margin	%	0.50	0.50	0.50	N/A	N/A	N/A

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Total Boiler Loss	%	12.46	17.09	14.06	NA	NA	NA
Boiler Efficiency	%	87.54	82.91	85.94	N/A	N/A	N/A
Total Heat Output from Boiler	mmBtu/hr	4,798.43	4,798.43	4,798.43	NA	NA	NA
Main Steam Flow	lb/hr	4,248,925	4,248,925	4,248,925	1,491,728	1,410,067	1,508,954
STEAM TURBINE/CYCLE DATA (Per Turbine):							
Turbine Back Pressure	in HgA	2	2	2	2	2	2
Steam Turbine Gross Output	kW	685,000	685,000	685,000	262,031	247,208	262,794
LP Turbine Exhaust to Condenser	lb/hr	2,627,921	2,627,921	2,627,921	2,305,964	1,483,005	2,305,964
Exhaust Energy	Btu/lb	1,015.90	1,015.90	1,015.90	1,015.80	1,021.40	1,015.80
Condensate Enthalpy	Btu/lb	69.1	69.1	69.1	69.1	69.1	69.1
Heat Rejection from LP Turbine	mmBtu/hr	2,488	2,488	2,488	2,183	1,412	2,183
BFP Turbine Drive Steam Flow	lb/hr	0	0	0	0	0	0
BFP Turbine Exhaust Enthalpy	Btu/lb	0.00	0.00	0.00	0.00	0.00	0.00
Heat Rejection from BFP Turbine	Btu/hr	0	0	0	0	0	0
Total Heat Rejected to Condenser	mmBtu/hr	2,488	2,488	2,488	2,183	1,412	2,183
Circulating Water Temp. Rise	°F	20.0	20.0	20.0	20.0	20.0	20.0
Circulating Water Flow	gpm	263,104	263,104	263,104	225,244	191,580	230,896
Number of Cooling Tower Cells		20	20	20	20	20	20
Total Circ. Water Flow	gpm	263,104	263,104	263,104	225,244	212,864	230,896
Service Water Flow	gpm	13,155	13,155	13,155	11,545	11,545	11,545
Total Cooling Water Requirement	gpm	276,259	276,259	276,259	236,789	224,409	242,441
GAS TURBINE DATA (Per Turbine):							
Gas Turbine Power	Gross-kW	N/A	N/A	N/A	232,015	232,015	232,015
	Btu/kWh						
PLANT AUXILIARY POWER:							
Induced Draft Fan Pressure Rise	"wc	44.0	44.0	41.8	NA	NA	NA
Boiler	"w.c	8.0	8.0	8.0	NA	NA	NA
Econ Outlet to SCR outlet	"w.c	6.0	6.0	6.0	NA	NA	NA
SCR Outlet to AH Outlet	"w.c	6.0	6.0	6.0	NA	NA	NA
AH Outlet to ESP Outlet	"w.c	0.0	0.0	0.0	NA	NA	NA
AH/ESP Outlet to COHPAC or Dry FGD/BH Outlet	"w.c	8.0	8.0	16.0	NA	NA	NA
COHPAC/Dry FGD BH Outlet to stack	"w.c	0.0	0.0	2.0	NA	NA	NA
ID inlet to Wet FGD outlet	"w.c	8.0	8.0	0.0	NA	NA	NA
Wet FGD outlet to stack outlet	"w.c	4.0	4.0	0.0	NA	NA	NA
Total ID fan static pressure	"w.c	40.0	40.0	38.0	NA	NA	NA
Percent Total Air to FD Fan	%	70	70	70	NA	NA	NA
Forced Draft Fan Pressure Rise	"wc	20	20	20	NA	NA	NA
Percent Total Air to PA Fan	%	30	30	30	NA	NA	NA
Primary Air Fan Pressure Rise	"wc	40	40	40	NA	NA	NA
Percent Total Air to SA Fan	%	0	0	0	NA	NA	NA
Secondary Air Fan Pressure Rise	"wc	15	15	15	NA	NA	NA
Condensate P/P	%	0.36	0.36	0.36	NA	NA	NA
Circulating Water P/P	%	0.46	0.46	0.46	NA	NA	NA
Cooling Towers	%	0.60	0.60	0.60	NA	NA	NA
Feedwater P/P	%	3.50	3.50	3.50	NA	NA	NA
Subtotal CWS	%	4.93	4.93	4.93	NA	NA	NA
Forced Draft Fan	%	0.34	0.37	0.36	NA	NA	NA
Induced Draft Fan	%	1.99	2.25	1.78	NA	NA	NA
Primary Air Fan	%	0.30	0.32	0.31	NA	NA	NA
Pulverizer	%	0.50	1.02	0.70	NA	NA	NA
Fuel Handling	%	0.12	0.22	0.16	NA	NA	NA
Ash Handling	%	0.19	0.60	0.14	NA	NA	NA
Wet ESP for H2SO4 collection	%	0.15	0.00	0.00	NA	NA	NA
Baghouse	%	0.12	0.12	0.12	NA	NA	NA
FGD	%	1.25	0.82	0.38	NA	NA	NA
Transformer Losses	%	0.20	0.20	0.20	0.20	0.20	0.20
Miscellaneous	.	1.00	1.00	1.00	0.80	0.80	0.80

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TOTAL Auxiliary Power	%	11.08	11.84	10.07	15.95	16.24	15.75
Net Unit Heat Rate	Btu/kWh	9,000	9,584	9,063	8,425	8,515	8,062
Plant Efficiency	%	37.9	35.6	37.6	40.5	40.1	42.3
ECONOMIC ANALYSIS INPUT:							
2008 to COD	years	5	5	5	7	7	7
Start of Engineering to COD	months	55	55	55	79	79	79
Operating Life	years	35	35	35	35	35	35
Levelized Fixed Charge Rate							
%/yr over operating life	%/yr	17.32%	17.32%	17.32%	17.32%	17.32%	17.32%
Total Staffing		100	100	100	120	120	120
Average Salary	$	85,563	85,563	85,563	85,563	85,563	85,563
Fixed Labor Costs	$	8,556,300	8,556,300	8,556,300	10,267,560	10,267,560	10,267,560
Fixed Non-Labor O&M Costs	$	8,014,500	8,014,500	8,014,500	19,603,437	24,031,042	19,942,349
Total Fixed O&M Costs	$	16,570,800	16,570,800	16,570,800	29,870,997	34,298,602	30,209,909
Fixed O&M Costs	$/net kW-yr	27.21	27.44	26.90	48.95	57.58	49.33
Property Taxes	$/year	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
FGD Reagent Cost							
$/ton, delivered		15.00	15.00	95.00	0.00	0.00	0.00
Activated Carbon							
$/ton, delivered		2200	2200	2200	10000	10000	10000
SCR Catalyst							
$/M^3		6000	6000	6000	6000	6000	6000
Ammonia (Anhydrous)							
$/ton, delivered		450	450	450	450	450	450
Water Cost							
$/1000 gallons		1.00	1.00	1.00	1.00	1.00	1.00
Fly Ash Sales	$/ton	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fly Ash Disposal	$/ton	$20.00	$20.00	$20.00	$0.00	$0.00	$0.00
Bottom Ash Sales	$/ton	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Bottom Ash Disposal	$/ton	$20.00	$20.00	$20.00	$0.00	$0.00	$0.00
Activated Carbon waste	$/ton	$20.00	$20.00	$20.00	$800.00	$800.00	$800.00
FGD Waste Sale	$/ton	$0.00	$0.00	$0.00	$100.00 sulfur	$100.00 sulfur	$100.00 sulfur
FGD Waste Disposal	$/ton	$20.00	$20.00	$20.00	$0.00	$0.00	$0.00
Other Variable O&M Costs	$/net-MWh	0.5	0.5	0.5	0.5	0.5	0.5
SO2 Allowance Market Cost							
$/ton		$500	$500	$500	$500	$500	$500
NOX Allowance Market Cost							
$/ton		$3,000	$3,000	$3,000	$3,000	$3,000	$3,000
Sulfur Byproduct							
$/ton		$0	$0	$0	$100	$100	$100
Equivalent Availability Factor	%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
Replacement Power cost	$/gross-kWh	0.065	0.065	0.065	0.065	0.065	0.065
Fuel Cost Delivered	$/mmBtu	1.70	1.50	1.40	1.70	1.50	1.40
$/ton, delivered		39.55	17.90	23.47	39.55	17.90	23.47
ECONOMIC ANALYSIS OUTPUT:							
Annual Capacity Factor	%/yr	90.00%	90.00%	90.00%	85.00%	85.00%	85.00%
Equivalent Full Load Hours	Hr's	7,880	7,880	7,880	7,450	7,450	7,450
Used for Potential to Emit (MW-hours@100%CF & Availability)	Mw-Hr/yr	4,799,572	4,758,478	4,854,401	4,546,232	4,438,115	4,562,121

PQA Study
Technology Spreadsheet
Efficiency/Heat Rate for New Coal-Fired Power Plants
Supercritical and IGCC

		Supercritical	Supercritical	Supercritical	subCritical	subCritical	subCritical
Base set-up for meeting Target BACT limits for NOX & SO2	**UNITS**	**685MW - Supercritical PC, Bituminous**	**685MW - Supercritical PC, Lignite**	**685MW - Supercritical PC, PRB**	**726 MW - IGCC, Bituminous**	**711MW - IGCC, Lignite**	**727MW - IGCC, PRB**
Capital costs	$1,000						
Direct & Indirect Costs $1000	$1,000	2,217,840	2,461,143	2,090,180	2,800,491	3,433,006	2,848,907
$/kW Capital Cost based on net	$/net-kw	3,641	4,076	3,393	4,589	5,763	4,652
Capital Costs							
Costs in year 2008 dollars	$1,000	2,217,840	2,461,143	2,090,180	2,800,491	3,433,006	2,848,907
Fixed O&M Costs							
Fixed O&M Costs	$1,000	16,571	16,571	16,571	29,871	34,299	30,210
Variable O&M Costs ($/yr)							
Limestone Reagent	$1,000	2,455	1,276	0	0	0	0
Lime Reagent, dryFGD, MDEA,Catalysts	$1,000	0	0	1,174	1,593	1,415	1,340
Activated Carbon	$1,000	0	1,751	1,593	296	1,068	296
Water	$1,000	440	440	440	451	407	440
Bottom Ash Sale/Disposal	$1,000	721	2,740	473	0	0	0
Fly ash sale/Disposal	$1,000	2,877	10,954	1,884	0	0	0
Gypsum sale/Disposal	$1,000	5,051	2,635	617	0	0	0
AC Waste Disposal	$1,000	0	16	14	24	85	24
Ammonia	$1,000	577	609	587	186	186	186
SCR-Catalyst Replacement	$1,000	1,153	1,153	1,153	399	399	399
Bags for Baghouse	$1,000	367	415	378	33	61	42
SO2 Allowances	$1,000	1,080	913	880	191	189	184
NOx Allowances	$1,000	3,241	3,422	3,301	431	425	414
Other	$1,000	2,401	2,380	2,428	2,272	2,218	2,280
Sulfur Sale	$1,000	N/A	N/A	N/A	555	272	65
Total	$1,000	20,364	28,705	14,924	6,430	6,725	5,668
Variable O&M Costs	$/MWh	3.73	5.76	3.07	1.42	1.52	1.24
Total Non-Fuel O&M Cost	$1,000	36,935	45,276	31,495	36,301	41,023	35,878
Total Non-Fuel O&M Cost	$/MWh	7.69	9.51	6.48	7.99	9.25	7.87

APPENDIX F

IGCC POWER PLANT COST ESTIMATE DETAILS

PQA
Greenfield IGCC Plant Study
Order of Magnitude Cost Study
Summary of Estimated Project Costs

Unit Size, MW Net	610	612	596
Configuration	Greenfield Shell Design with Illinois Bituminous # 6	Greenfield Shell Design with PRB	Greenfield Shell Design with Texas Lignite
Coal & Sorbent Handling	36,007,000	42,023,000	34,171,000
Coal & Sorbent Prep & Feed	159,390,000	173,908,000	252,127,000
Feedwater & Misc. BOP Systems	48,779,000	48,865,000	47,104,000
Gasifier & Accessories			
Gasifier, Syngas Cooler, & Auxiliaries	378,962,000	450,206,000	581,514,000
ASU / Oxidant Compression	170,396,000	168,704,000	154,933,000
Other Gasification Equipment	65,182,000	70,114,000	78,962,000
Subtotal Gasifier & Accessories	614,540,000	689,024,000	815,409,000
Gas Cleanup & Piping	145,163,000	87,368,000	130,083,000
Combustion Turbine & Accessories			
Combustion Turbine & Generator	124,519,000	124,519,000	124,519,000
Combustion Turbine, Other	2,648,000	2,648,000	2,648,000
Subtotal Combustion Turbine & Accessories	127,167,000	127,167,000	127,167,000
HRSG, Ducting, & Stack			
Heat Recovery Steam Generator	52,218,000	52,218,000	52,218,000
Ductwork & Stack	15,850,000	15,850,000	15,850,000
Subtotal HRSG, Ducting, & Stack	68,068,000	68,068,000	68,068,000
Steam Turbine Generator			
Steam Turbine Generator & Accessories	50,783,000	50,796,000	50,515,000
Turbine Plant Auxiliaries & Steam Piping	32,575,000	32,632,000	31,457,000
Subtotal Steam Turbine Generator	83,358,000	83,428,000	81,972,000
Cooling Water System	36,331,000	36,395,000	35,084,000
ASH / Spent Sorbent Handling System	48,704,000	37,794,000	119,767,000
Accessory Electric Plant	67,228,000	67,099,000	66,389,000
Instrumentation & Controls	33,073,000	33,073,000	33,073,000
Improvements to Site	23,287,000	23,287,000	23,287,000
Buildings & Structures	24,743,000	24,743,000	24,743,000
Subtotal Direct Project Costs	**1,515,838,000**	**1,542,242,000**	**1,858,444,000**
Indirect Project Costs.	$125,972,000	$127,871,000	$154,084,000
Contingency @ 20%	328,362,000	334,023,000	402,506,000
Owner's Costs @ 3%	49,254,000	50,103,000	60,376,000
Operating Spare Parts @ 1%	16,418,000	16,701,000	20,125,000
Escalation (4% Annual Rate)	346,098,000	352,127,000	424,322,000
Interest During Construction (6% Annual Rate)	418,549,000	425,840,000	513,149,000
Total Project Costs	**2,800,491,000**	**2,848,907,000**	**3,433,006,000**
$/kW Net	**4,589**	**4,652**	**5,763**

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Notes:
1. The contracting scheme is assumed to be multiple lump sum. EPC contracting, if obtainable, would warrant additional fees.
2. Total Project Cost represents cost at completion for a project started 01/09 and completing 12/15, a 7 year overall schedule.
3. Labor costs are based on the Gulf Coast region of the U.S. Adjustments will be required for other regions of the country.
4. Owner's Costs are highly variable. Included here as an allowance at 3% of Subtotal Project Costs.
5. Escalation calculated at 4% annual rate, compounded annually and based on projected 7-year cash flow.
6. IDC calculated at 6% annual rate, compounded annually and based on projected 7-year cash flow.

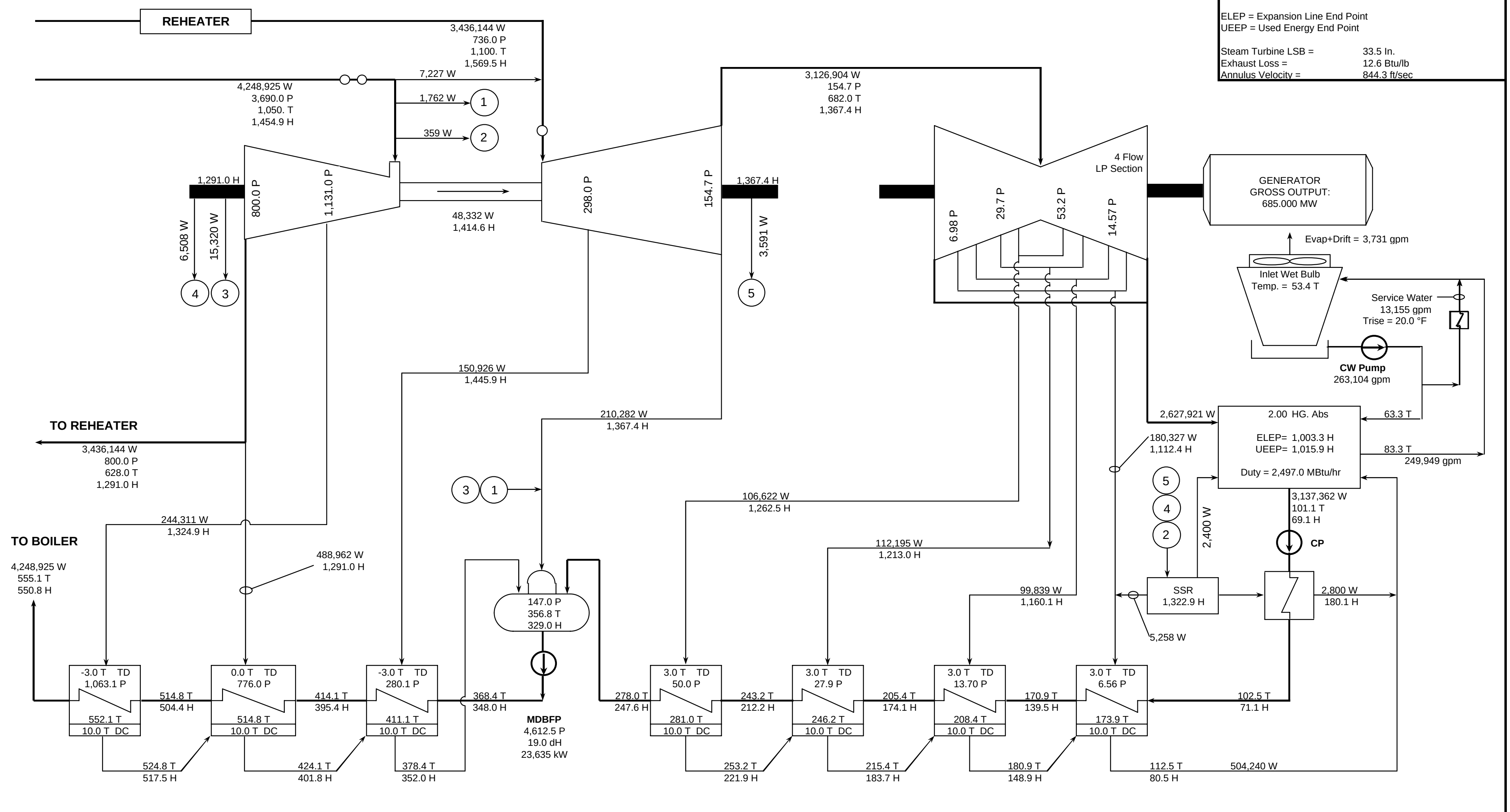
APPENDIX G

SC AND IGCC POWER PLANT HEAT BALANCES

Note:
Expected Plant Performance, Not Guaranteed.
Calculation based 1997 ASME Steam Table

ELEP = Expansion Line End Point
UEEP = Used Energy End Point

Steam Turbine LSB =	33.5 In.
Exhaust Loss =	12.6 Btu/lb
Annulus Velocity =	844.3 ft/sec



Ambient Dry Bulb =	59.0 T
Ambient Wet Bulb =	51.4 T
Relative Humidity =	60.0%
Site Elevation (AMSL) =	1 ft
Steam Turbine Gross =	685.0 MW

Gross Turbine Heat Rate = Heat Input / Generator Output **= 7,005 Btu/kWh**

Net Turbine Heat Rate = Heat Input / (Generator Output - Power to Motor) **= 7,255 Btu/kWh**

PRELIMINARY
For Information Only

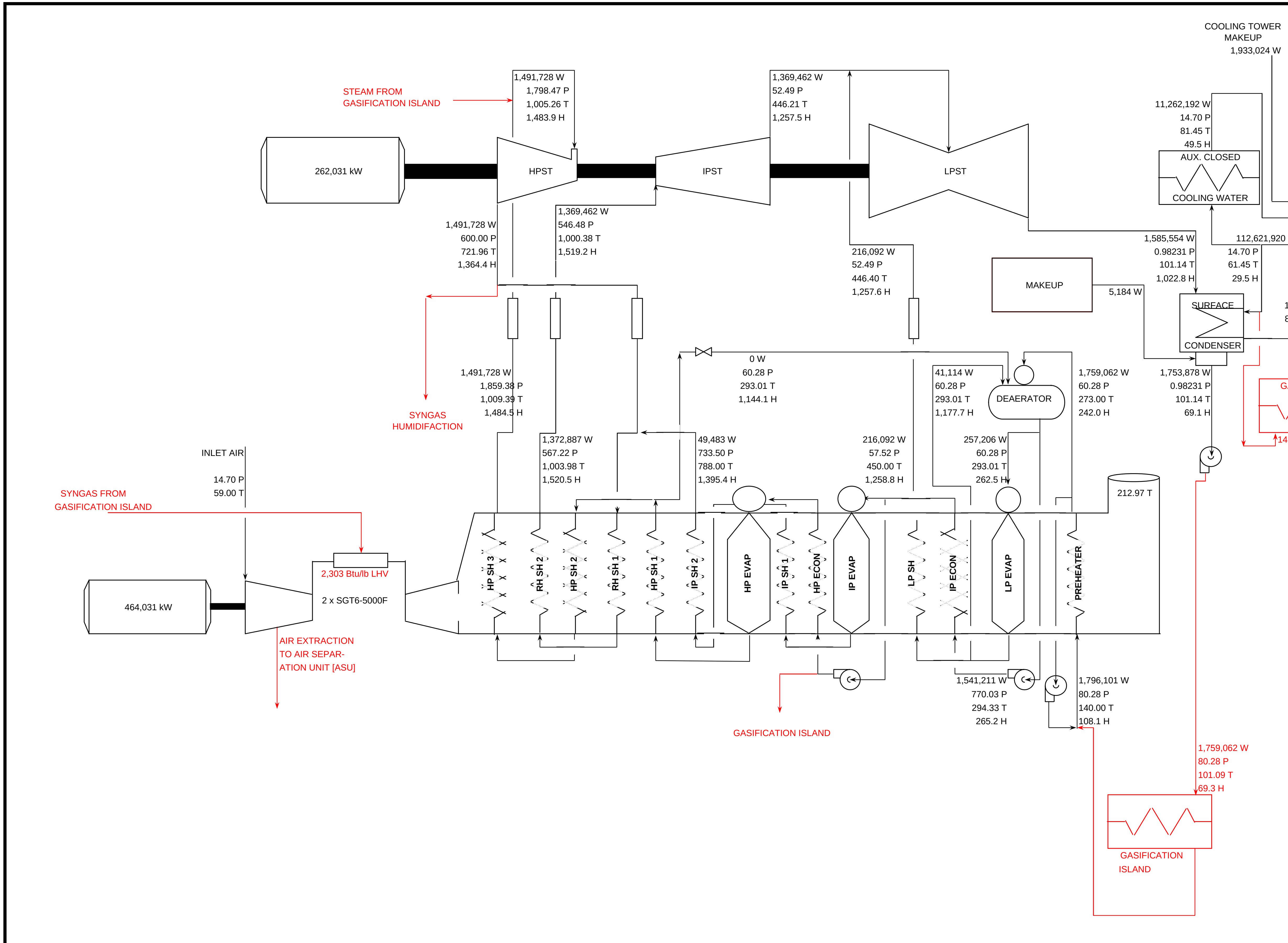
Legend:
W= Flow, lb/hr
P= Pressure, Psia
T= Temperature, °F
H= Enthalpy, Btu/lb

Drawing Release Record

Rev.	Date	Prepared	Reviewed	Approved	Purpose	Project No.:
0	12/10/2008	L.Papadopoulos			Feasibility Study	12301-003
						GateCycle Model/Case

POA STUDY
SUPERCRITICAL
685 MW
3690 P / 1050 T / 1100 T

Sargent & Lundy LLC



#	Notes
1	All flows are water/steam unless otherwise indicated.
2	LP ST is a 2-flow end unit with 40" last stage blades.
3	Heat rate is calculated on basis of HHV.
4	Both CTs and HRSGs are currently modeled as a single unit.
5	ST generator efficiency is 98.4%
6	Cooling tower drift rate is set at 0.0005%
7	Gasification plant components and flows printed in red.
8	All flows for SGT6-5000F are for two turbines, corrected for alt. and temp.
9	Cooling tower operates at 6 cycles of concentration.
10	Steam / Feedwater to SRS returned to cycle through makeup system.
11	Maximizing CT Power Output, Adjusting Air Extraction

W [Flow] in lb/hr	1 lb/hr = 0.000126 kg/sec = 0.001997 US gpm (water)
P [Pressure] in psi(a)	1 psi = 0.068947 bar 1 psi = 2.036 in Hg
T [Temperature] in °F	(°F - 32) * 5/9 = °C (°C * 9/5) + 32 = °F
H [Enthalpy] in Btu/lb	1 Btu/lb = 2.326122 kJ/kg

PLANT PERFORMANCE SUMMARY

Ambient Dry Bulb Temperature	59.00 F 15.00 C
Ambient Wet Bulb Temperature	51.47 F 10.82 C
Ambient Relative Humidity	60.00%
Ambient Site Pressure	14.70 psia 1.013 bar
Site Equivalent Elevation, AMSL	0 ft 0 m
Gas Turbine Gross Output	464,030 kW
Steam Turbine Gross Output	262,031 kW
Plant Auxiliary Loads	115,829 kW
Net Plant Electrical Output	610,232 kW
IGCC Plant Heat Input(5,220 t/day Coal AR@11,631 BTU/lb HHV)	5,140,902,000 Btu/hr 5,423,939,431 kJ/hr
GROSS IGCC Plant Heat Rate, HHV	7,080.5 Btu/kWhr 7,470.4 kJ/kWhr
NET IGCC Plant Heat Rate, HHV	8,424.5 Btu/kWhr 8,888.3 kJ/kWhr

DRAWING RELEASE RECORD

REV.	DATE	PREPARED BY	REVIEWED BY	APPROVED BY
0	11/26/2008	L.Papadopoulos	D. Hasler	R. Gaikwad
1	5/8/2009	L.Papadopoulos	D. Hasler	R. Gaikwad

REV.	Purpose

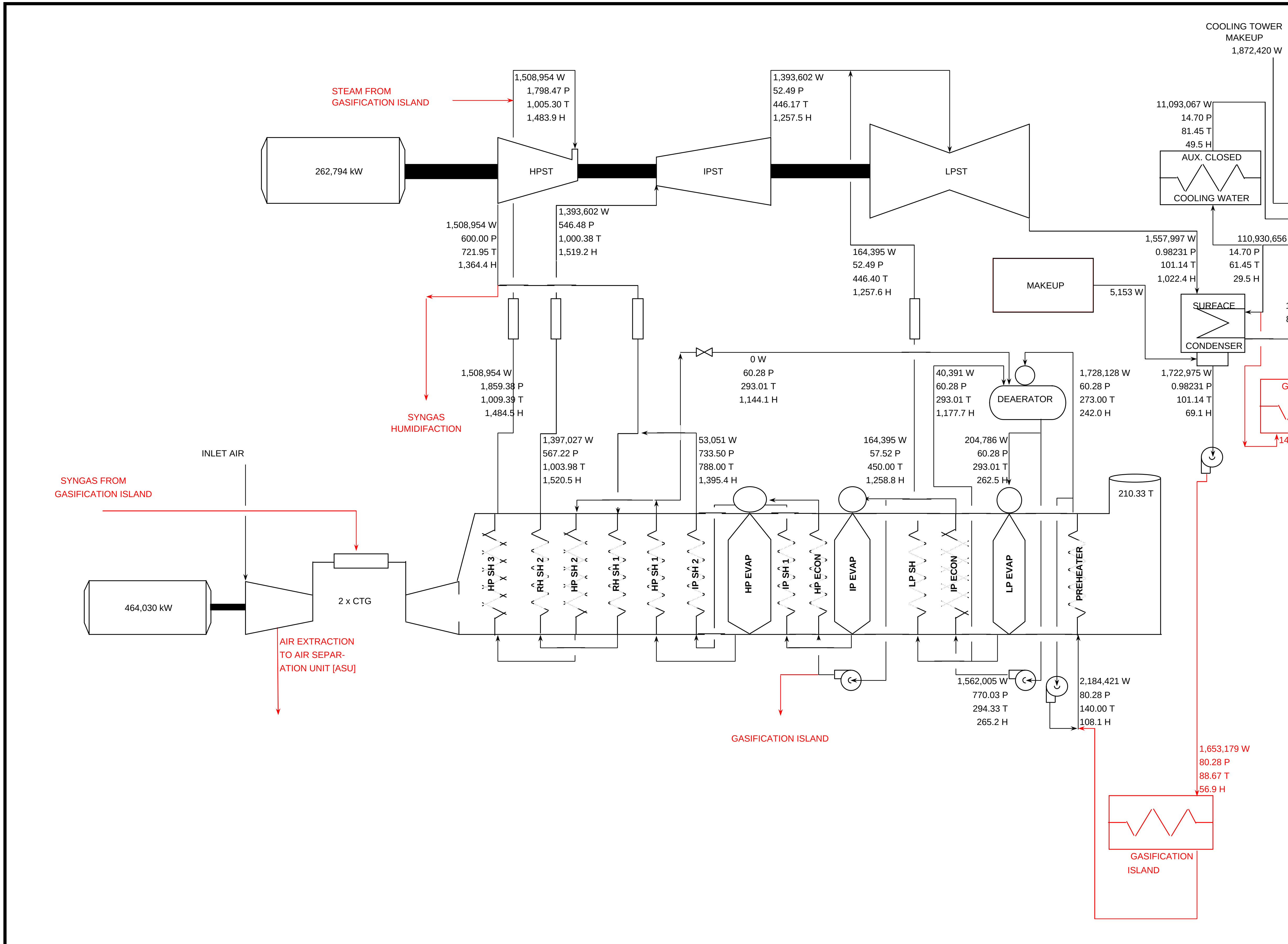
Unit System	GateCycle Model/Case		Project - Part
US CUSTOMARY	NWCARL	EX	12301-003

Sargent & Lundy LLC

PQA STUDY

PERFORMANCE HEAT BALANCE

Fuel: Illinois #6 Bituminous Coal Dried to 2% wt.



#	Notes
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PLANT PERFORMANCE SUMMARY

Ambient Dry Bulb Temperature	59.00 F 15.00 C
Ambient Wet Bulb Temperature	51.47 F 10.82 C
Ambient Relative Humidity	60.00%
Ambient Site Pressure	14.70 psia 1.013 bar
Site Equivalent Elevation, AMSL	0 ft 0 m
Gas Turbine Gross Output	464,030 kW
Steam Turbine Gross Output	262,794 kW
Plant Auxiliary Loads	114,459 kW
Net Plant Electrical Output	612,365 kW
IGCC Plant Heat Input(7,068 t/day Coal AR@8,382 BTU/lb HHV)	4,936,998,000 Btu/hr 5,208,809,295 kJ/hr
GROSS IGCC Plant Heat Rate, HHV	6,792.6 Btu/kWhr 7,166.5 kJ/kWhr
NET IGCC Plant Heat Rate, HHV	8,062.2 Btu/kWhr 8,506.1 kJ/kWhr

DRAWING RELEASE RECORD

REV.	DATE	PREPARED BY	REVIEWED BY	APPROVED BY
0	11/26/2008	L.Papadopoulos	D. Hasler	R. Gaikwad

REV.	Purpose

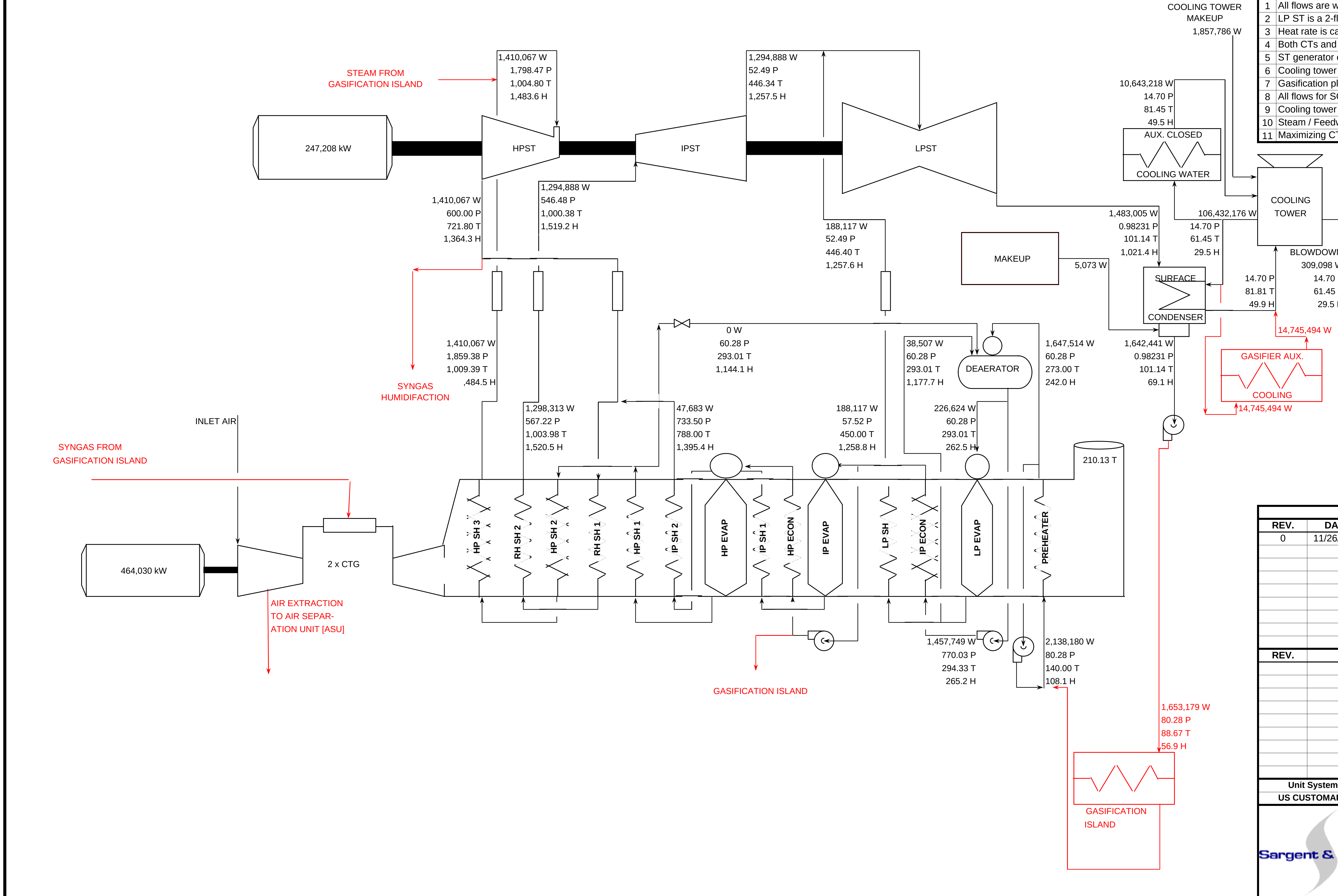
Unit System	GateCycle Model/Case		Project - Part
US CUSTOMARY	NWCARL	EX	12301-003

Sargent & Lundy LLC

PQA STUDY

PERFORMANCE HEAT BALANCE

Fuel: PRB
Dried to 6% wt.



#	Notes
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2	LP ST is a 2-flow end unit with 40" last stage blades.
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Ambient Relative Humidity	60.00%
Ambient Site Pressure	14.70 psia 1.013 bar
Site Equivalent Elevation, AMSL	0 ft 0 m
Gas Turbine Gross Output	464,030 kW
Steam Turbine Gross Output	247,208 kW
Plant Auxiliary Loads	115,518 kW
Net Plant Electrical Output	595,720 kW
IGCC Plant Heat Input(10,200 t/day Coal AR@5,968 BTU/lb HHV)	5,072,800,000 Btu/hr 5,352,088,009 kJ/hr
GROSS IGCC Plant Heat Rate, HHV	7,132.3 Btu/kWhr 7,525.0 kJ/kWhr
NET IGCC Plant Heat Rate, HHV	8,515.4 Btu/kWhr 8,984.2 kJ/kWhr

DRAWING RELEASE RECORD

REV.	DATE	PREPARED BY	REVIEWED BY	APPROVED BY
0	11/26/2008	L.Papadopoulos	D. Hasler	R. Gaikwad

REV.	Purpose

Unit System	GateCycle Model/Case		Project - Part
US CUSTOMARY	NWCARL	EX	12301-003

Sargent & Lundy LLC

PQA STUDY

PERFORMANCE HEAT BALANCE

Fuel: Texas Lignite
Low Moisture
Dried to 7% wt.