CONCEPTUAL DESIGN AND ECONOMICS OF
A NOMINAL 500 MWe
SECOND-GENERATION PFB COMBUSTION PLANT

FINAL TECHNICAL REPORT

By:

A. Robertson   Foster Wheeler Development Corporation

H. Goldstein   Parsons Infrastructure and Technology Group Incorporated

D. Horazak   Siemens Westinghouse Power Corporation

R. Newby   Siemens Westinghouse Power Corporation

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ABSTRACT

Research has been conducted under United States Department of Energy Contract DE-AC21-86MC21023 to develop a new type of coal-fired plant for electric power generation. This new type of plant, called a Second Generation Pressurized Fluidized Bed Combustion Plant (2^{nd} Gen PFB), offers the promise of efficiencies greater than 48 percent, with both emissions and a cost of electricity that are significantly lower than those of conventional pulverized coal-fired (PC) plants with wet flue gas desulfurization.

The 2^{nd} Gen PFB plant incorporates the partial gasification of coal in a carbonizer, the combustion of carbonizer char in a pressurized circulating fluidized bed boiler, and the combustion of carbonizer syngas in a gas turbine combustor to achieve gas turbine inlet temperatures of 2300°F and higher.

A conceptual design and an economic analysis was previously prepared for this plant. When operating with a Siemens Westinghouse W501F gas turbine, a 2400psig/1000ºF/1000ºF/2-1/2 in. Hg. steam turbine, and projected carbonizer, PCFB, and topping combustor performance data, the plant generated 496 MWe of power with an efficiency of 44.9 percent (coal higher heating value basis) and a cost of electricity 22 percent less than a comparable PC plant. The key components of this new type of plant have been successfully tested at the pilot plant stage and their performance has been found to be better than previously assumed. As a result, the referenced conceptual design has been updated herein to reflect more accurate performance predictions together with the use of the more advanced Siemens Westinghouse W501G gas turbine. The use of this advanced gas turbine, together with a conventional 2400 psig/1050°F/1050°F/2-½ in. Hg. steam turbine increases the plant efficiency to 48.2 percent and yields a total plant cost of $1,079/KW (January 2002 dollars). The cost of electricity is 40.7 mills/kWh, a value 12 percent less than a comparable PC plant.

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Executive Summary

Introduction

The electric utility industry needs a new generation of coal fueled plants that can operate with substantially improved efficiencies, accept lower quality fuels, and easily meet present and future New Source Performance Standards (NSPS). Experimental tests have shown that pressurized fluidized beds (PFB) can be excellent vehicles for combusting or gasifying coal. Since they operate at elevated temperatures and pressures, their exhaust gases can be used to fuel/power gas turbines as well as generate steam for steam turbines. By integrating PFB gasification with PFB combustion, electricity producing, combined cycle, gas turbine-steam turbine plants can be designed with efficiencies greater than 48 percent based on the coal higher heating value (HHV). The cost of electricity generated by this new type of plant is calculated to be 12 percent less than that of a pulverized coal fired (PC) plant with wet flue gas desulfurization and its emissions are well below NSPS limits. Since this plant incorporates the best features of gasification and combustion technologies, it is considered a technology hybrid; the plant is named a Second Generation (2nd Gen) PFB Combustion Plant.

A team of companies led by Foster Wheeler Development Corporation (FWDC) and consisting of:

1.) Foster Wheeler Power Group Inc.
2.) Foster Wheeler USA Inc.
3.) Institute of Gas Technology
4.) Parsons Infrastructure and Technology Group Inc.
5.) Siemens Westinghouse Power Corporation (SWPC)

has conducted R&D for the development of the technologies required by this new plant. The work was conducted in three phases under United States Department of Energy (DOE) Contract No. DE-AC21-86MC21023. In the first phase, the proposed plant was conceptually designed and its performance, economics, and emissions were determined at a nominal 500 MWe size [ES-1][*]. The R&D needs of the plant were also identified and, in the second phase of the project, its key components e.g. the PFB gasifier, PFB combustor, and gas turbine combustor were tested separately at a pilot plant scale. The separate tests were all successful and in the third phase the PFB gasifier, PFB combustor, and the ceramic candle filters that stripped their gases of entrained particulate were tested successfully as an integrated subsystem, again at a pilot plant scale. The key component tests yielded performance levels that were higher than originally projected. As a result the Phase 1 conceptual plant design, called the baseline plant, has been updated herein to reflect that pilot plant experience and the use of newer, commercially available gas turbines and steam turbines. In addition the effects of alternative operating conditions on plant performance and economics were investigated in a sensitivity study.

Study Results

The updated 2nd Gen PFB plant design incorporates a Siemens Westinghouse W501G gas turbine and a 2400psig/1050F/1050F/2-½ in. Hg. steam turbine. Table ES-1 summarizes 2nd Gen PFB

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[*] brackets designate references listed in Section 9

plant performance and economics and compares it to a comparable PC plant designed for the same high sulfur Pittsburgh No 8 coal, limestone, sulfur capture efficiency, NOx emission rate, and steam cycle conditions. The comparison, which is based on 2nd Gen PFB Sensitivity Study Case 4, continues to show the attractiveness of this new type of plant. The 2nd Gen PFB Combustion Plant has:

1. a 24 percent higher efficiency.........................48.2 versus 38.9 percent (HHV)
2. a 10 percent lower total plant cost.................$1,079 versus $1,202/KW
3. a 12 percent lower cost of electricity..............40.7 versus 46.4 mills/kWh
4. a 41 percent lower water consumption...........359 versus 606 gal/MWe
5. a 19 percent lower SO_2 emission ....0.99 versus 1.22 lb/hr/MWe
6. a 19 percent lower CO_2 emissions.................1,458 versus 1,819 lb/hr/MWe
7. a 92 percent lower particulate emission..........0.021 versus 0.263 lb/hr/MWe

The 2nd Gen PFB and PC plants have been designed to operate with 97 percent sulfur capture efficiency. Since the PC plant scrubber operates with a higher sorbent utilization factor, the 2nd Gen PFB plant requires a 35 percent higher limestone feed rate. Despite this, the plant waste flow rates are essentially the same because of the efficiency advantage (less coal and coal ash) of the 2nd Gen PFB plant.

Table ES-1 Comparison of Nominal 500 MWe 2nd Gen PFB and PC Plants

	2nd Gen PFB*	PC with FGD	2nd Gen Advantage
Plant Performance			
HHV Efficiency, %	48.2	38.9	24%
Net Power, MWe	469.5	506	
Gross Power, MWe			
Gas Turbine (W501G)	239.5		
Steam Turbine (2400/1050/1050/2-1/2Hg)	250	547.4	
Emissions			
SO2, lb/hr/MWe (After 97% Sulfur Capture)	0.99	1.22	19%
NOx, lb/hr/MWe	1.22	1.22**	
CO2	1,468	1,819	19%
Particulate	0.021	0.263	92%
Plant Economics			
Total Plant Cost, $/KW	1,079	1,202	10%
Cost of Electricity, mills/kWh	40.7	46.4	12%
Other			
Pittsburgh 8 Coal	568.5	704.8	19%
Limestone, lb/hr/MWe	99.4	73.7	-35%
Waste, lb/hr/MWe			
Ash	177.5	68.4	
Fixed Scrubber Sludge		107.9	
Total	177.5	176.3	-1%
Water Consumption, gal/MWe	358.7	605.9	41%

** Sensitivity Study Case 4 Plant Configuration*

***Low NOx Burners and SCR Provided to Match 2nd Gen NOx Rate*

Peak Efficiency Plant Concept

The proposed peak efficiency 2nd Gen PFB plant is shown schematically in Figure ES-1. The air required by the plant is supplied by the air compressor of a Siemens Westinghouse W501G gas turbine operating with a nominal 19 to 1 pressure ratio. Approximately 55 percent of the compressor air is exported from the gas turbine for use by the PFB gasifier and the PFB combustor. The exported air is boosted in pressure by an external axial flow compressor that compensates for the air/gas pressure losses associated with the PFBs. The exported air ultimately returns as two nominally 1600ºF streams; the first is a low-Btu, coal derived syngas from the PFB gasifier and the second is an oxygen rich flue gas/vitiated air from the PFB combustor/ boiler. The oxygen rich flue gas supports the combustion of the syngas in the gas turbine combustor, called the topping combustor, and the plant incorporates a 2400psig/1050ºF/1050ºF/ 2½ in. Hg. steam turbine.

The plant operates as follows:

Coal and limestone, both dried and crushed to a minus 1/8 inch size, are blended together, pressurized via a lock hopper system, and pneumatically transported to/injected into a jetting/bubbling bed PFB gasifier called the carbonizer. The carbonizer partially gasifies the coal and produces a low-Btu syngas and a char-sorbent residue. After passing through a cyclone and ceramic barrier filter that remove gas-entrained particulate and alkali vapors, the syngas is burned in a topping combustor to produce the energy required to drive the W501G gas turbine. The gas turbine drives a generator and the compressor that feeds air to the carbonizer and the PCFB boiler with its Intrex**J** fluidized bed heat exchangers (FBHE). The carbonizer char is burned in the PCFB boiler with 50 percent excess air and the combustion exhaust gas/flue gas passes through its own cyclone and ceramic barrier filter for particulate and alkali vapor removal. The oxygen rich flue gas proceeds to the gas turbine and supports combustion of the syngas. Steam from the PCFB boiler and a heat-recovery unit (HRU) downstream of the gas turbine drives the steam turbine generator that furnishes the balance of electric power delivered by the plant. The waste from the plant is a mixture of spent sorbent and fly ash drained from the bottom of the PCFB boiler and its filter vessels. The PCFB boiler bottom ash is cooled, mixed with the filter fines, depressured via a restricted pipe discharge/lock hopper arrangement, further cooled, and pneumatically transported to silos for landfill disposal.

The low-Btu syngas is produced in the carbonizer by pyrolysis/mild devolatilization of coal in a fluidized bed reactor. Because this unit operates at relatively low temperatures, e.g., 1600ºF to 1800ºF, it also produces a char residue. Left untreated, the syngas will contain hydrogen sulfide and sulfur-containing tar/light oil vapors; therefore, lime-based sorbents are injected into the carbonizer along with the coal to catalytically enhance tar cracking and to capture sulfur as calcium sulfide. Sulfur is captured in situ, and the syngas is fired hot.

The char and calcium sulfide produced in the carbonizer and contained in the syngas as elutriated particles are captured by high-temperature filters, rendering the syngas essentially particulate free and able to meet NSPS. The captured particulate and carbonizer bed drains are collected in a central hopper and injected into the PCFB boiler through a steam-aerated non-mechanical valve. The air in the PCFB boiler supports the combustion of the char and transforms the calcium sulfide to sulfate.

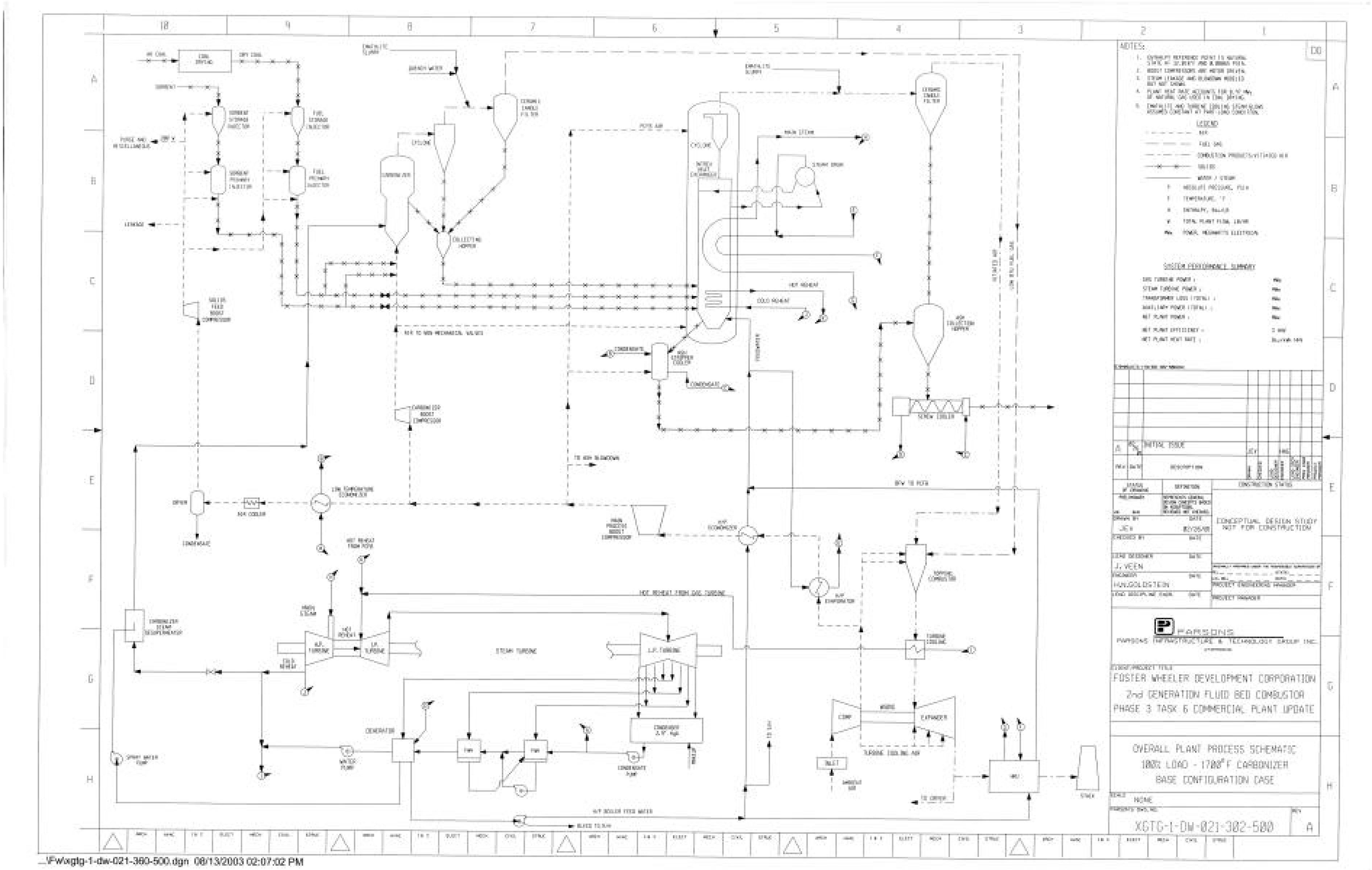

Figure ES-1 Simplified Schematic of 2nd Gen PFB Combustion Plant

The burning char heats the combustion air-flue gas to 1600EF and the surplus heat is transferred to the FBHEs by the recirculation of solids (sorbent and coal fly ash). Controlled recirculation is accomplished with cyclone separators and non-mechanical valves. The FBHEs contains tube surfaces that cool the circulating solids. Because of the low fluidizing velocity in the FBHEs (#1 ft/s), the risk of tube erosion is virtually eliminated.

The exhaust gases leaving the carbonizer and PCFB boiler primary stage cyclones contain sorbent, fly ash particles, and alkali vapors which can erode, foul, and corrode downstream equipment. Pulverized emathelite mixed with water is sprayed into these gas streams as a slurry that quickly evaporates and leaves the emathelite to capture the alkali vapors. Ceramic barrier candle filters remove the emathelite and remaining particulate from the gases before they enter the gas turbine, thus preventing erosion, fouling, and corrosion.

The gas turbine combustor, which consists of metallic-wall multi-annular swirl burners (MASBs), is provided in a can-annular burner arrangement around the gas turbine circumference. Each MASB contains a series of swirlers that aerodynamically create fuel-rich, quick-quench and fuel-lean zones to minimize NOx formation during the topping combustion process. The swirlers also provide a thick layer of air at the wall boundary to control the temperature of the metallic walls.

Operating Envelope/Factors Influencing Plant Efficiency

Depending upon the gas turbine operating conditions, plant excess air level, steam turbine conditions, steam turbine size, carbonizer and PCFB boiler operating temperatures, etc. many plant configurations and outputs are possible. In simplistic terms, when designing a 2nd Gen PFB plant, the starting point is the gas turbine. Selection of the gas turbine establishes the amount of air available for the plant and the next step is to determine the plant coal flow rate. Since the gas turbine is more efficient and more expensive on a dollar per kilowatt basis than the steam turbine, the objective is to fully load the gas turbine. Hence the minimum coal flow rate to the plant is that which generates enough syngas to reach the gas turbine full load firing temperature. When that coal flow is compared to the available air flow, the plant is observed to be operating at high excess air and additional coal can be burned. With no additional syngas being required, the additional coal flow can be directed to the PCFB boiler which increases the heat input to the steam cycle. If this additional heat input increases the efficiency of the steam cycle, e.g., increases steam temperatures and pressures, the plant efficiency will increase. Once the maximum steam turbine operating conditions are achieved, the plant is at its peak efficiency. Typically there is still excess air available at this point. From this point on further heat input to the PCFB boiler will, in essence, only increase the size of the steam turbine; since the steam turbine is less efficient than the gas turbine the plant efficiency will begin to decrease. In the extreme, increasing coal flow to the PCFB boiler will reduce the plant excess air to that minimum level required to support gas turbine topping combustion. At this point both the steam turbine and the overall plant power output are at a maximum, this is called the maximum power or minimum excess air plant. With steam turbine power being less expensive than gas turbine power, as shown in [ES-1], the maximum power plant configuration can yield a lower cost of electricity than the peak efficiency plant. Hence a 2nd Gen PFB plant can be designed for peak efficiency, maximum power output, or any point in between with each offering a design specific output, efficiency, cost of electricity, and emissions. The range in plant outputs, however, will depend on the gas turbine firing temperature. A gas turbine with a high firing temperature compared to one with a lower firing temperature will require more syngas firing, more char combustion and, hence, have less excess air available for additional coal combustion. To show the range of possibilities available with the W501G, the peak efficiency point was selected as the baseline plant configuration for this study; the effects of a maximum power design as well as other alternative operating conditions on the plant were investigated in a sensitivity study.

Carbonizer

The carbonizer operating temperature significantly affects syngas yields, compositions, and heating values. Higher temperatures increase the amount of coal energy transferred to the syngas and enable operation at the highest gas turbine firing temperatures. If the carbonizer temperature is too high, ash softening could form high temperature agglomerates that impair fluidization; if the temperature is too low tar/oil vapors released during the devolatilization of the coal would not be destroyed/cracked and their condensation could foul downstream equipment. If highly caking coals are being gasified excessively low temperature can also result in agglomeration. A 12 inch diameter carbonizer has been tested by FWDC at pressures as high as 200 psig with subbituminous and bituminous coals and fluidizing velocities of 3 and 4 ft/sec [ES-4]. A 1600ºF to 1800ºF temperature range was found to be a comfortable operating envelope for highly caking bituminous coals and 1700ºF was selected for the baseline plant carbonizer; the plus or minus 100ºF variation in operating temperature allowed by 1700ºF is more than enough to compensate for any foreseen variation in coal quality/reactivity.

FWDC’s pilot plant tests have shown that a jetting bed configuration can produce gas turbine quality syngas from a wide range of coals, even highly caking coals, without agglomeration or tar/oil vapor problems. In addition, cold model tests conducted by other investigators in units up to 10 ft. in diameter have demonstrated its scalability to large size units [ES-5]. As a result a bubbling fluidized bed configuration with fluidizing air injected as a high velocity jet at the base of the unit was selected for the carbonizer. The coal and limestone/dolomite sorbent are injected into the unit within and coaxial with the centerline of the air jet. The jet, being oxygen rich, creates a localized hot spot that insures tar/oil vapor destruction. The jet rapidly disperses the feed material within the bed, and induces internal solids recirculation; bed material flows upward on the centerline of the unit, down along the walls, and re-enters the jet at the bottom of the unit to control the jet temperature. The continuous circulation of bed material back into the jet and the effect of particle impacts caused by the high velocity jet prevents over size material from forming.

Under other programs funded by the DOE, FWDC has taken its 12 in. diameter carbonizer test unit, reduced its internal diameter to 7 inches by the installation of additional refractory, and operated it as a circulating fluidized bed partial gasifier at velocities up to 16 ft./sec. A wide range of coals, petroleum coke, and sawdust were successfully tested and for applications requiring large syngas flow rates, a circulating bed may be a more economical configuration for the carbonizer. An analysis to determine the most economical configuration for the baseline plant, however, was beyond the scope of this study and the jetting bed configuration used in the original plant design was again used in the plant update.

PCFB Boiler

FW possesses PCFB combustion pilot plants at its research facilities in New Jersey and Finland. The latter unit is the larger of the two (plan view cross section is 22 inches square) and it has accumulated over 10,000 hours of test time with a wide variety of coals. The former PCFB has a 13 inch inside diameter and, although it has less operating time, it has been used to successfully combust carbonizer chars from a variety of fuels, i.e., subbituminous and bituminous coals and petroleum coke [ES-6]. The operating conditions selected for the baseline plant PCFB boiler, i.e., 16 ft/sec gas velocity, 1600ºF bed temperature, 50 percent excess air, etc., fall within the range of conditions tested. The plan view dimensions of the riser/furnace section of the PCFB boiler are roughly 5 ft. 6 in. by 14 ft. 7 in. Although these dimensions are much larger than those of the pilot plants, experience in supplying atmospheric pressure CFB boilers has shown that circulating fluidized beds can be scaled with confidence. Hence, the performance predicted for the baseline plant PCFB boiler, being based on pilot plant experience, is believed to be an accurate representation of a commercial scale unit.

Ceramic Candle Filters

To protect the gas turbine from corrosion, erosion, and deposition the carbonizer syngas and the PCFB boiler flue gas/vitiated are stripped of gas entrained particulate by their passage through ceramic candle filters. The carbonizer and PCFB filter systems both operate at a nominal 1600ºF, utilize silicon carbide candles manufactured by Schumacher, and are of a design developed by Siemens Westinghouse. Each filter vessel is about 10 ½ feet in diameter and contains 748 candles; each candle is nominally 2-3/8 inches in diameter by 60 inches long and contains a “fail safe” which, should a candle break, quickly plugs and prevents particulate from escaping to the gas turbine. Ceramic candles have been tested at numerous facilities and the 91 candle unit at Wilsonville [ES-7] has demonstrated the ability to clean gases of particulate to less than 1 ppm. FW has tested ceramic candle filters in its gasification and combustion pilot plants. Although chars have been found to be free flowing, some combustion fly ashes can cause bridging in the filter hopper drain area and or between adjacent candles; both of these events, if left unchecked, can lead to broken candles. The tendency of fly ash to bridge in the filter is primarily a feed stock related phenomenon but, in some situations, can be caused by upstream precleaner devices that feed an excessively fine particle size to the filter.

FW’s pilot plant tests with the coal and dolomite proposed for the baseline plant indicate they should not cause char or a fly ash bridging problem, and, since the baseline plant does not incorporate any precleaning devices, the proposed filter design should operate free of ash problems. In the event other plants should encounter candle related ash bridging problems, they can be eliminated by removing upstream precleaner devices, changing the feedstock combination, utilizing a bottom supported rather than a cantilevered candle arrangement, reducing the filter operating temperature (1400ºF appears to solve the problem with all feedstocks), and or using more forgiving/less brittle candle materials of construction. As a result the performance and cost impact of several of these options e.g. use of limestone rather than dolomite, use of lower filter temperatures, and use of metal candles were investigated in a sensitivity study.

Topping Combustor

The syngas produced by the carbonizer has a lower heating value of approximately 140 Btu/SCF, possesses a hydrogen to carbon monoxide mole ratio of 0.85, and, depending upon operating conditions and the coal gasified, contains small amounts of ammonia. Although the syngas heating value is much lower than that of natural gas, it is well above Siemens Westinghouse's minimum value limit of 90 Btu/SCF and its relatively high hydrogen content will enhance flame speed and stability. The syngas is combusted by the oxygen contained in the PCFB boiler vitiated air and, to maximize the plant efficiency, the syngas and PCFB boiler flue gas are "fired" hot/enter the gas turbine topping combustor at ~1600ºF. Because of its low heating value, little thermal NOx is generated during syngas combustion but since the ammonia can potentially be converted to NOx staged combustion is utilized.

To minimize NOx formation, provide high combustion efficiency, and accommodate high gas temperatures, the 2nd Gen PFB Combustion Plant topping combustor utilizes metallic-wall multi-annular swirl burners (MASBs) developed by Siemens Westinghouse. Each MASB contains a series of swirlers that aerodynamically create fuel-rich, quick-quench and fuel-lean zones that minimize NOx formation during the topping combustion process while providing high combustion efficiency with PCFB boiler flue gas. The swirlers also provide a thick layer of air at the wall boundary that controls the temperature of the metal walls. The MASB has been successfully tested with a five component gas mixture simulating carbonizer syngas and performed equally as well with natural gas [ES-8]. The MASB thus has a dual fuel capability (both syngas and natural gas) and is provided in a typical can-annular burner arrangement around the circumference of the W501G gas turbine.

Sensitivity Study

Since 2nd Gen PFB Combustion Plants are a new technology, a sensitivity study was conducted to determine how their performance and, in some cases, economics are affected by alternative operating conditions or design features. In most of the cases only one variable was changed at a time so effects could be clearly seen. A total of eight cases were investigated from a performance standpoint and four included economics for comparison to a conventional PC plant with wet flue gas desulfurization. To permit a fair comparison, the PC plant was designed to operate with the same coal, limestone, steam turbine conditions, sulfur capture efficiency, and NOx emission rate. To achieve the same emissions the PC plant utilizes a high efficiency SO_2 scrubber and incorporates low NOx burners and SCR. With these features the PC plant operates with an efficiency of 38.9 percent, a total plant cost of $1,202/KW, and a cost of electricity of 46.4 mills/kWh.

Table ES-1 summarizes the results of the sensitivity study. The baseline plant, which operates with Pittsburgh No 8 coal and Plum Run dolomite, produces 477.5 MWe of electrical power with a W501G gas turbine and a 2400 psig/1050ºF/1050ºF/2½ in. Hg. steam turbine. The plant efficiency is 48.0 percent (HHV basis), the total plant cost $1,083/KW, and the cost of electricity 41.9 mills/kWh. The plant can operate equally as well with either limestone or dolomite as its sulfur capturing sorbent. When limestone, which has about 22 percent more calcium per pound of sorbent than dolomite, is used (Case 1), sorbent and ash flows reduce and the plant efficiency increases by 0.2 percentage points to 48.2 percent. Total plant costs are essentially unchanged but because of its slightly higher efficiency the cost of electricity reduces slightly to 40.9 mills/kWh.

Table ES-2 Sensitivity Study Results

Case	Description	Net Output, MWe	HHV Efficiency, %	Total Plant Cost, $/KW	COE, mills/kWh	COE % less than PC**
	Baseline Plant	477.56	48.0	1,083	41.9	9.7
1	with Limestone Sorbent	469.51	48.2	1,085	40.9	11.9
2	with Large Filter Vessels	477.56	48.0	1,077	41.7	9.9
3	with Metal Filters	467.36	45.8	1,124	43.0	7.3
4	with Limestone & Large Filter Vessels	469.51	48.2	1,079	40.7	12.3
5	with Large Steam Turbine	490.31	47.8	ND*	ND*	ND*
6	with Post Gas Turbine CO2 Removal	329.24	33.1	ND*	ND*	ND*
7	with Pre-Gas Turbine CO2 Removal	422.10 Preliminary	35.4 Preliminary	ND*	ND*	ND*
8	with Supercritical Steam Turbine	984.50	50.5	ND*	ND*	ND*

* Not Determined
** Pulverized Coal-Fired Plant with FGD at $1,202/KW and COE of 46.4 mills/kWh

Ceramic candles are used to filter particulate from the gases proceeding to the gas turbine. The largest ceramic candle filter vessel supplied by Siemens Westinghouse at the time of this study was nominally 10 feet in diameter and contained 748 candles. To be conservative, this same filter arrangement was assumed for the baseline plant and resulted in the need for eight vessels. Filter vessels nominally 16 feet in diameter and incorporating 1,496 candles also appear feasible and were investigated next. By using 16 foot diameter filter vessels (Case 2), only four rather than eight filter vessels are required and there is a slight reduction in plant costs; total plant costs reduce to $1,077/KW with a cost of electricity of 41.7 mills/kWh.

Because of the high temperature of the carbonizer syngas and PCFB boiler flue gas (~1600ºF), ceramic candles are used to filter/remove particulate from these gases. Ceramic candles are known to be brittle and excessive temperature shocks and ash bridging can cause them to fail. An alternative approach would be to replace them with lighter, more ductile, porous metal candles made from iron aluminide material. The latter are commercially available for operation up to 1400ºF. In Case 3 the syngas and flue gas streams are cooled to 1200ºF and 1000ºF respectively by heat transfer to the steam cycle to allow the use of iron aluminide candles. Although the latter can be furnished in up to 96 inch lengths, the same nominal 60 inch ceramic candle length was used to preclude a complete redesign of the filter vessels. Cooling the gas streams increases the size of the less efficient steam cycle and the plant efficiency reduces to 45.8 percent. The porous metal candles, being more expensive than the silicon carbide ceramic candles, increases the total plant costs to $1,124/KW with a cost of electricity of 43.0 mill/kWh. These costs, however, are considered to be an upper bound as it is felt a redesign of the filter system, based on a fewer number of lighter, 96 inch long candles, would result in a slight reduction.

In Case 4 the use of limestone sorbent together with the large ceramic candle filter vessels were combined. Being a combination of Cases 1 and 2 the plant efficiency is 48.2 percent and costs reduce to $1,079/KW and 40.7 mills/kWh.

The gas turbine combustor of the baseline plant operates with 70 percent excess air which yields a 4.1 percent oxygen level in its exhaust and 7.3 percent at the stack. Siemens Westinghouse believes that with development the gas turbine combustor can operate with as little as 1.5 percent oxygen in its exhaust. This lower value would allow the plant to operate with additional coal flow and hence additional power output. With the gas turbine fully loaded the added power would come from the steam turbine. Even though this will decrease the plant efficiency (steam cycle operates with a lower efficiency than the gas turbine cycle), the total plant cost and the cost of electricity will decrease because steam turbine power is less expensive; this was demonstrated in [ES-1]. In Case 5 the plant coal flow was increased by approximately 3 percent or 8,634 lb/hr to lower the oxygen level of the gas turbine combustor exhaust to a modest 3.5 percent; this decreased the plant efficiency from 48.0 to 47.8 percent but yielded a 12.75 MWe increase in plant output. Although not calculated, total plant cost and cost of electricity are expected to be slightly less than that of the baseline, e.g., $1,083/KW and 41.9 mills/kWh.

The baseline plant operates with a 2400psig/1050ºF/1050ºF/2-1/2 in. Hg. steam cycle. In Case 8 a more efficient supercritical pressure double reheat steam cycle (4000psig/1100ºF/1100ºF/1100ºF/2½ in. Hg.) was used. With the latter only being available in larger sizes, the plant output increases to 984.5 MWe and the efficiency rises to 50.5 percent (was 48.2 percent).

With CO_2 known to be a greenhouse gas, there is growing interest in removing CO_2 from power plant stack gases for pipeline transport to a sequestering site. In the 2nd Gen PFB Combustion Plant the CO_2 can be removed either downstream or upstream of the gas turbine. If downstream removal is utilized, large gas volumes with low CO_2 contents are encountered but the required absorber/stripper systems operate at about atmospheric pressure; pre-gas turbine removal involves much smaller gas volumes with higher CO_2 concentrations but the two gas streams, e.g., carbonizer syngas and PCFB flue gas must be treated in separate absorber systems operating at about 275 psig. The effect on plant performance of 90 percent CO_2 removal, including cooling, drying, and pressuring to 1200 psig for pipeline transport, via these two approaches was investigated. Post gas turbine CO_2 removal (Case 6) was investigated first. It required the use of a chemical absorption (inhibited MEA) solvent that had a high heat duty requirement for stripping; this together with a 27.9 MWe CO_2 compressor power draw reduced the plant output to 329.2 MWe and an efficiency of 33.1 percent. Since pre-gas turbine CO_2 removal (Case 7) occurs at elevated pressure where gas volumes are smaller and CO_2 partial pressures and concentrations are higher (dilution effect of gas turbine combustion and cooling air is eliminated), a physical absorption solvent may also be used. Screening calculations by UOP, a supplier of these solvents, indicated chemical absorption via their Amine Guard FS would result in a lower demand for steam and parasitic power. Although a more intensive analysis would be required by UOP to optimize the performance of the Amine Guard FS system, rough sizing factors were given that would enable a plant configuration to be established and its preliminary performance estimated. FWDC's proprietary computer codes were used to configure the plant and, with pre-gas turbine CO_2 removal, the plant efficiency is predicted to be 34.5 percent; since this value is based on rough UOP sizing factors, it is considered preliminary pending completion of a more in depth analyses.

Conclusions and Commercial Readiness

A 2nd Gen PFB Plant is a technology hybrid that incorporates the best features of coal combustion and coal gasification technologies. By combining their best features, a combined cycle, gas turbine-steam turbine plant configuration is achieved that yields plant efficiencies and economics superior to either technology. To match the emissions of a 2nd Gen PFB Plant, a PC fired plant must incorporate 97 percent efficient wet FGD, low NOx burners and SCR. When compared to that comparable PC plant, a 2nd Gen PFB Plant designed for peak efficiency operates with:

1.) a 24 percent higher efficiency...........................48.2 versus 38.9 percent (HHV)
2.) a 10 percent lower total plant cost....................$1,079 versus $1,202/KW
3.) a 12 percent lower cost of electricity................40.7 versus 46.4 mills/kWh
4.) a 41 percent lower water consumption.............359 versus 606 gal/MWe
5.) a 19 percent lower SO_2 emission ....0.99 versus 1.22 lb/hr/MWe
6.) a 19 percent lower CO_2 emission.....................1,458 versus 1,819 lb/hr/MWe
7.) a 92 percent lower particulate emission............0.021 versus 0.263 lb/hr/MWe

A 2nd Gen PFB Plant operates with crushed coal and limestone, does not require an oxygen generating air separation unit, can accommodate mercury and CO_2 removal, and can easily incorporate future gas turbine and steam turbine advances that can further increase its efficiency advantage. In addition, the plant offers design flexibility. It can be designed for peak efficiency, maximum power, or any point in between.

When designed for peak efficiency, the plant operates with relatively high excess air and its coal derived gases are fired hot (enter gas turbine combustor at ~1600ºF) to minimize the size of the less efficient steam turbine. In the maximum power configuration, the coal derived gases can be cooled to 1000ºF before they reach the gas turbine by heat transfer to the steam cycle and coal fed to the PCFB boiler to maximize the size of the steam turbine. Cooling the coal derived gases eases design requirements of downstream components, simplifies system designs, and reduces risks. Depending upon the gas turbine used, the steam turbine power can be doubled and, even though the plant efficiency reduces by about two to four percentage points, a high efficiency (~44 to 46 percent) is still achieved. Since steam turbine power is relatively inexpensive, the maximum power configuration can yield a lower cost of electricity than the peak efficiency plant. A 2nd Gen PFB Plant can also be designed to operate between either of these two extremes, thus making it an ideal choice for repowering applications where the requirements of an existing steam turbine have to be matched.

A 2nd Gen PFB Plant thus offers electric utilities high efficiency, low emissions, low costs, and a design flexibility that allows it to incorporate future turbine advances for increased efficiency or additional processing steps for future mercury and CO_2 control; these features make it ideally suited for meeting the present and future needs of the electric power industry.

All of the key, new components of a 2nd Gen PFB Plant have been tested separately at the pilot plant scale and their individual performance characteristics are understood. Although all of the tests have been successful, they were of relatively short duration (hundreds of hours) and the 1600ºF components, e.g., candle filters and gas turbine combustor require more test time to demonstrate their long term durability before a peak efficiency plant is ready for demonstration. Since the maximum power configuration allows gas temperatures to be cooled to 1000ºF, its high temperature component risks are eliminated and commercially proven porous metal candle filters and conventional gas turbine valving and combustors can be used. As a result, a small scale, maximum power, 2nd Gen PFB Demonstration Plant can be built today with minimal technology risks. The design of such a first of a kind plant requires engineering redesign and development, such as, gas turbines must be redesigned/modified to allow exporting of large air flows and importing 1000ºF gases, new mechanical designs developed for placing CFB boilers within pressure vessels, the performance of new components and systems must be modeled and their integration schemes and characteristics defined, etc. Recognizing that these efforts involve multiple manufacturers, it is unlikely that the low risk demonstration plant would proceed until the R&D required by the ultimate peak efficiency plant is performed. Once this R&D is successfully completed, manufacturers would be able to see potential future market growth from the low risk demonstration plant to the ultimate peak efficiency configuration and enable them to justify their engineering commitments. As a result, it is recommended that DOE continues the development of high temperature candle filters and gas turbine combustors via testing and operation of a relatively small scale plant in which all the key components, e.g., carbonizer, PCFB boiler, candle filters, MASBs, and gas turbine are fully integrated for the first time. This would greatly reduce uncertainties and enhance the commercialization potential of this new power production technology.

Section 1

INTRODUCTION

Research has been conducted under United States Department of Energy (DOE) Contract DE-AC21-86MC21023 to develop a new type of coal-fired plant for electric power generation. This new type of plant, called a Second Generation Pressurized Fluidized Bed Combustion Plant (2nd Gen PFB), offers the promise of efficiencies greater than 45 percent, with both emissions and a cost of electricity that are significantly lower than those of conventional pulverized coal-fired (PC) plants with wet flue gas desulfurization/scrubbers.

In the plant, coal is fed to a pressurized fluidized bed gasifier, called the carbonizer, that produces a low-Btu syngas and char. After passing through a cyclone and ceramic barrier filter to remove gas-entrained particulate and alkali vapors, the syngas is burned in a topping combustor to produce the energy required to drive a gas turbine. The gas turbine drives a generator and a compressor that feeds air to the carbonizer and a pressurized circulating fluidized bed (PCFB) combustor/boiler with its IntrexJ/fluidized bed heat exchangers (FBHE). The carbonizer char is burned in the PCFB boiler; the exhaust gas passes through its own cyclone and ceramic barrier filter for particulate and alkali vapor removal, and supports combustion of the syngas in the topping combustor. Steam generated in the PCFB boiler and a heat-recovery unit (HRU) downstream of the gas turbine drives the steam turbine generator that furnishes the balance of electric power delivered by the plant.

The low-Btu syngas is produced in the carbonizer by the pyrolysis/mild devolatilization of coal using air and steam. Because this unit operates at temperatures much lower than gasifiers currently under development, it also produces a char residue. Left untreated, the syngas will contain hydrogen sulfide and sulfur-containing tar/light oil vapors; therefore, lime-based sorbents are injected into the carbonizer to catalytically enhance tar cracking and to capture sulfur as calcium sulfide. Sulfur is captured in situ, and the syngas is fired hot.

The char and calcium sulfide produced in the carbonizer and contained in the syngas as elutriated particles are captured by high-temperature filters, rendering the syngas essentially particulate free and able to meet New Source Performance Standards (NSPS). The captured particulate and carbonizer bed drains are collected in a central hopper and injected into the PCFB boiler through a nitrogen-aerated non-mechanical valve. The excess air in the PCFB boiler transforms the calcium sulfide to sulfate and enables its disposal with the normal PCFB spent sorbent.

In the PCFB boiler, the burning char heats the combustion air-flue gas to 1600°F; any surplus heat is transferred to the FBHE by the recirculation of solids (sorbent and coal fly ash) between the units. Controlled recirculation is accomplished with cyclone separators and non-mechanical valves. The FBHE contains tube surfaces that cool the circulating solids. Because of the low fluidizing velocity in the FBHE ($\leq$1 ft/s), the risk of tube erosion is virtually eliminated.

The exhaust gases leaving the carbonizer and the PCFB boiler cyclones contain sorbent, char, fly ash, and alkali vapors that can erode, foul, and corrode downstream equipment. Pulverized emathelite is sprayed into these gas streams via a water slurry to capture the alkali vapors. The emathelite and remaining gas entrained particulate are stripped from the gases by ceramic barrier filters and the cleaned gases proceed to the gas turbine topping combustor.

The topping combustor consists of metallic-wall multi-annular swirl burners (MASBs) provided in a can-annular burner arrangement around the gas turbine circumference. Each MASB contains a series of swirlers that aerodynamically create fuel-rich, quick-quench and fuel-lean zones to minimize NOx formation during the topping combustion process. The swirlers also provide a thick layer of air at the wall boundary to control the temperature of the metallic walls.

A team of companies led by Foster Wheeler Development Corporation (FWDC) and consisting of:

1.) Foster Wheeler Power Group Inc.
2.) Foster Wheeler USA
3.) Parsons Infrastructure and Technology Group Inc.
4.) Institute of Gas Technology
5.) Siemens Westinghouse Power Corporation (SWPC)

previously prepared a conceptual design and an economic analysis of a nominal 500 MWe 2nd Gen PFB combustion plant [ES-1]. The plant, which operated with 2.9 percent sulfur Pittsburgh No 8 coal, a Siemens Westinghouse 501F gas turbine, and a 2400 psig/1000°F/1000°F/2½ in. Hg. steam turbine, was calculated to have an efficiency of 44.9 percent and a cost of electricity 21.8 percent lower than that of a comparable PC plant. Since performing that study, the key components of this new type of plant have been successfully tested at the pilot plant stage and their performance found to be better than initially assumed.

In the following sections of this report a new conceptual design and economic analysis is presented for the 2nd Gen PFB combustion plant. Each of the team members determined the performance and costs of the equipment within their scope of supply and Parsons determined overall plant performance and costs. The updated/new design reflects more accurate component performance predictions together with the use of the more advanced Siemens Westinghouse W501G gas turbine and a 2400 psig/1050°F/1050°F/2½ in. Hg. steam turbine. This effort includes a sensitivity study that identifies how plant performance and, in some cases, economics are affected by alternative operating/design conditions. The performance and economics of the updated 2nd Gen PFB Combustion Plant design are also compared to those of a comparable updated PC plant.

Section 2

SECOND-GENERATION PFB BASELINE PLANT

2.1 PLANT SITE DESCRIPTION/CONDITIONS

The plant site is assumed to be in the Ohio River Valley of southwestern Pennsylvania/eastern Ohio. The site consists of approximately 180 usable acres (not including ash disposal) within 15 miles of a medium-sized metropolitan area and with a well-established infrastructure capable of supporting the required construction work force. The area immediately surrounding the site is a mixture of agriculture and light industry. The site is served by a river with adequate flow for use as makeup cooling water after minimal pretreatment and for the receipt of cooling system blowdown discharges. In addition, the river is a navigable waterway suitable for shipping coal and sorbent to the site. A railroad line that can handle unit coal trains passes within 2½ miles of the site boundary. The site is served by a well-developed road network capable of carrying AASHTO H-20 5-16[*] loads, with overhead restrictions not lower than 16 ft (Interstate Standard).

The site is on relatively flat land with a maximum difference in elevation within the site of about 30 ft. The topography of the area surrounding the site is rolling hills with elevations within 2000 yd not more than 300 ft above the site elevation.

The site is within Seismic Zone 1, as defined by the Uniform Building Code, and the ambient design conditions are:

Barometric Pressure	14.4 psia
Dry bulb temperature	60°F
Wet bulb temperature	52.5°F

A sufficient work force of well-trained construction laborers is available within a 50-mile radius of the site. Labor conditions are such that a "Project Work Agreement" can be obtained from labor organizations and contractors. All necessary bulk construction material is available locally and can be delivered within a reasonable period of time.

This generic site has been used to prepare conceptual designs of the 2nd Gen PFB Combustion Plant (baseline) and a reference conventional PC plant. Although specific site conditions will dictate design changes, the conclusions in this report should be valid.

2.2 PROCESS DESCRIPTION

The key to the baseline plant concept is an air-blown carbonizer that partially gasifies coal and provides low-Btu syngas to a gas turbine topping combustor and a char residue to a pressurized circulating fluidized bed (PCFB) boiler; the latter burns the char with relatively high excess air and produces an oxygen rich flue gas/vitiated air that supports the combustion of the syngas and generates steam for a steam turbine. Figure 2.2.0.1 is an overall process schematic of the plant.

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[*] American Association of State Highway and Transportation Officials

Figure 2.2.0.2 presents the full-load heat and mass balance diagram of the baseline plant and illustrates the functional arrangement of the major plant components.

The plant utilizes a carbonizer/PCFB/gas turbine module operating with one steam turbine, to produce 477.5 MWe of net electrical power. The data and flow rates are presented in Figure 2.2.0.2.

2.2.1 Feedstocks

The baseline plant has been designed for Pittsburgh No. 8 coal and Plum Run dolomite. Analyses of these feedstocks are presented in Tables 2.2.1.1 and 2.2.1.2, and the plant operates with a calcium-to-sulfur (Ca/S) molar feed ratio of 1.75.

2.2.2 Gas and Solids Systems

A description of the plant process begins most easily with the gas turbine, since all other processes are dependent on the gas turbine operating point. Approximately 45 percent of the gas turbine compressor air flow is used for gas turbine blade and combustor liner cooling; the balance proceeds to the carbonizer/PCFB area. The latter, at approximately 19 atm/811°F, is cooled to a nominal 600EF by an evaporator and economizer in the high pressure steam circuit and then proceeds to the main boost compressor. The main boost compressor increases the air pressure to a nominal 21 atmospheres to compensate for pressure drops induced by the carbonizer and PCFB components; a second boost compressor, acting on a small portion of this flow, provides high pressure air for lock hopper pressurization and pneumatic transport of feed materials. The critical path that establishes pressure drop in the plant is the flow of air through the PCFB boiler. As a result, a butterfly type valve is provided in the carbonizer syngas path to compensate for the difference in gas path pressure drops.

Expressed as a percentage of total flow the gas turbine air is used in the following approximate distribution at full load:

- 4% for lock hopper pressurization and pneumatic transport of feed materials
- 11% to the carbonizer
- 40% to the PCFB boiler
- 45% for gas turbine cooling

During full-load operation, all plant coal and sorbent, sized at 1/8-in. x 0, are fed to the carbonizer by three 50 percent capacity lock hopper type pneumatic transport feed systems. During start-up, shutdown, and part-load operation, coal and limestone are also fed directly to the PCFB boiler by a similar but smaller pair of lock hopper type pneumatic transport feed systems. Boost compressors provide the higher pressure air required to pressurize their lock hoppers and transport their feed materials to the carbonizer and PCFB boiler.

For reliable feed of solids, the surface moisture of the coal and dolomite should be limited to 5 percent. Dryers supplied with flue gas extracted from the gas turbine heat recovery unit (HRU) accomplish this task. The dryers are also provided with oil burners that are used during plant start-up when hot flue gas is not available.

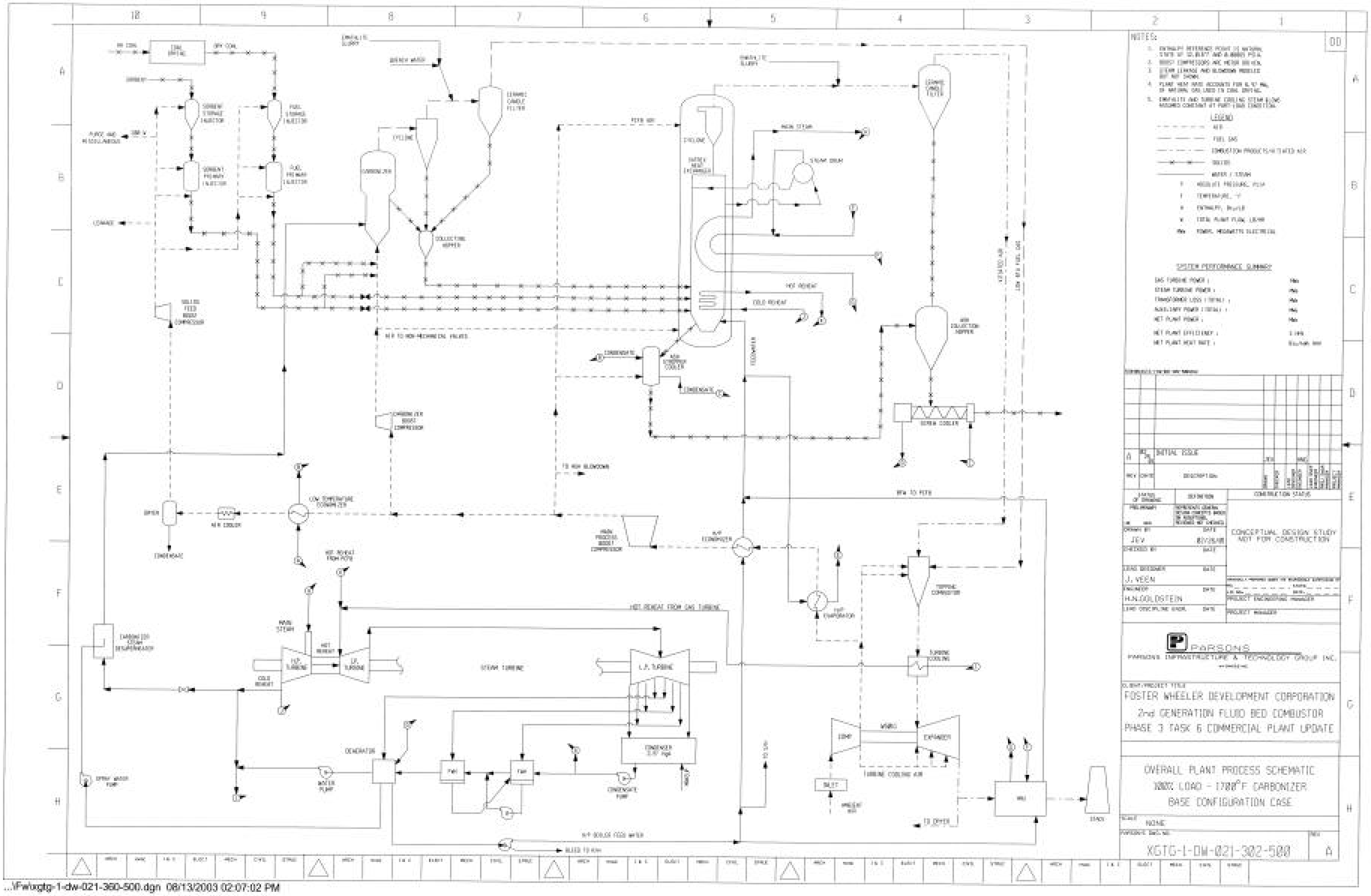

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Figure 2.2.0.1 Overall Plant Process Schematic

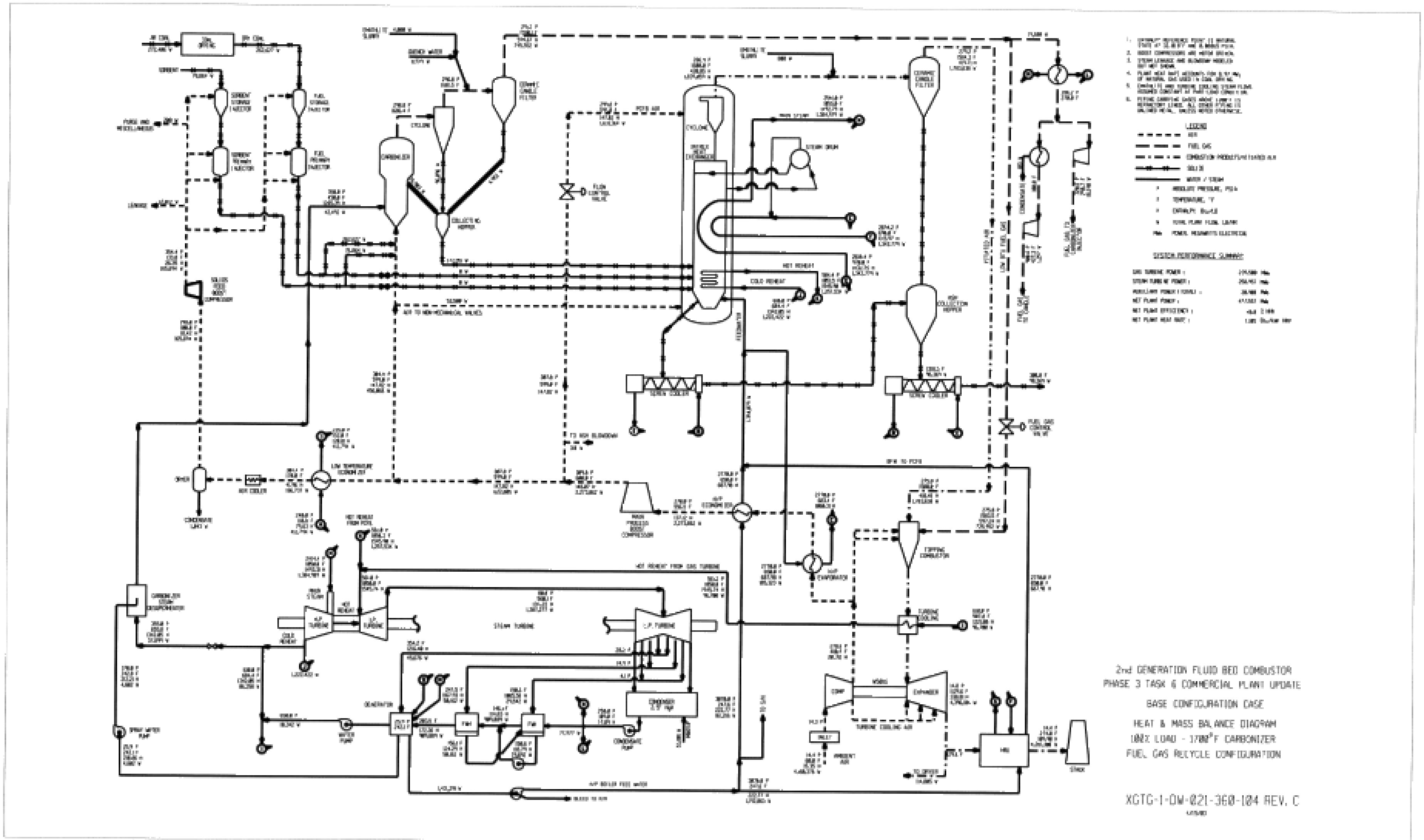

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Figure 2.2.0.2 Full Load H&M

Table 2.2.1.1 Pittsburgh No. 8 Coal Analysis

Constituent	As Received%
Carbon	69.36
Hydrogen	5.18
Nitrogen	1.22
Sulfur	2.89
Ash	9.94
Oxygen	11.41
Total	100.00

	As Received%
Moisture	6.00
Ash	9.94
Volatile Matter	35.91
Fixed Carbon	48.15
Total	100.00
Sulfur	2.89
Btu	12,450

Ash Analysis,%

Silica, SiO_2	48.1
Aluminum Oxide, $A1_2O_3$	22.3
Iron Oxide, Fe_2O_3	24.2
Titanium Dioxide, TiO_2	1.3
Calcium Oxide, CaO	1.3
Magnesium Oxide, MgO	0.6
Sodium Oxide, Na_2O	0.3 (0.9% in Coal)
Potassium Oxide, K_2O	1.5 (0.15% in Coal)
Sulfur Trioxide, SO_3 0.8	
Phosphorous Pentoxide, P_2O_5	0.1
Total	100.5

Ash Fusion Temperature, EF (EC)

	Reducing Atmosphere	Oxidizing Atmosphere
Initial Deformation	2015 (1102)	2570 (1410)
Spherical	2135 (1168)	2614 (1434)
Hemispherical	2225 (1218)	2628 (1442)
Fluid	2450 (1343)	2685 (1474)

Table 2.2.1.2 Plum Run Dolomite Analysis

	Dry Basis%
Calcium Oxide, CaO	31.2
Magnesium Oxide, MgO	21.2
Silica, SiO_2	0.20
Aluminum Oxide, $A1_2O_3$	0.53
Iron Oxide, Fe_2O_3	0.60
Sulfur Trioxide, SO_3	0.29
Carbon Dioxide, CO_2	45.4
Chlorine, Cl	0.05
Balance	0.53
Water-Soluble Components, % as received	
Sodium as Na_2O	0.013
Potassium as K_2O	0.002

The syngas generated by the carbonizer is cleaned of particulate via a cyclone and ceramic candle filter and proceeds to the gas turbine. The captured particulate, together with char-sorbent residue draining continuously from bed overflow nozzles in the carbonizer, drain to collecting hoppers that use “N” shaped non-mechanical valves to transfer the material to the PCFB boiler.

The PCFB boiler burns the carbonizer char and:

- Produces 1600°F vitiated air/flue gas for the topping combustor.
- Captures/converts sulfur released as sulfur dioxide during the char combustion process to calcium sulfate.
- Converts calcium sulfide in the carbonizer sorbent residue to calcium sulfate.

To remove elutriated bed material, the exhaust gas from the PCFB boiler is passed through a ceramic candle filter. Solids captured by the filter are depressured and then cooled in screw coolers.

After passing through their respective ceramic candle filter systems, the carbonizer and PCFB gases are conveyed to the gas turbine topping combustors by refractory-lined hot-gas piping. Metallic liners in the hot-gas piping from the ceramic filter to the topping combustor isolate the refractory and prevent any spalled refractory from entering the cleaned gases. The syngas is oxidized/burned in the topping combustor multi-annular swirl burners (MASBs) by the PCFB flue gas, producing a 2700°F (nominal) gas. The gas expands through the gas turbine, producing about 240 MWe (gross). A HRU at the discharge of the gas turbine cools the gas to 274°F, and the recovered heat is used for feedwater heating and steam superheating. Gas from the HRU is then ducted to a stack.

2.2.3 Steam and Feedwater Systems

The baseline plant steam turbine is similar to the turbine of a typical, modern 260-MWe power plant. However, the boiler and feedwater heating systems differ considerably from those in standard fossil-fuel-fired plants because of the special characteristics of this PFB combustion cycle. The turbine is a 2400-psig reheat unit with 1050°F nominal temperatures for superheat and reheat steam. The major difference from a conventional steam turbine is that only three extractions are used during normal full-load operation, while a conventional fossil-fuel-fired plant with this size turbine would typically have seven or eight extractions for feedwater heating.

Heating and deaeration of low-pressure condensate are provided primarily by extraction steam. Two stages of closed feedwater heaters heat the condensate to 200°F (nominal), and the deaerator operates at 11.5 psig/240°F. About 31 percent of the condensate is diverted around the feedwater heater to cool air used by the lock hopper feed system and the ash from the PCFB boiler. The hot water leaving the screw coolers is discharged directly into the deaerator. Water from the deaerator is pressurized to 3070 psig by electrically driven booster pumps and feedwater pumps. Two 60 percent capacity pump trains are provided.

The 3070-psig feedwater is divided into two streams (Figure 2.2.0.2). The majority of the flow proceeds to the HRU for economizing and then on to the PCFB boiler steam drum for evaporation; similarly the much smaller balance proceeds to the combustion air cooler for economizing and on to its own steam drum for evaporation. The steam from the two drums is mixed and, after passing through the primary superheater in the PCFB, the secondary superheater in the HRU, and the final superheater in the PCFB, proceeds to the steam turbine at a nominal 1050EF.

After expanding through the high-pressure (HP) section of the steam turbine, the steam is reheated to a nominal 1050°F in the PCFB boiler, expanded through the steam turbine, and discharged to the plant steam condenser.

The HRU provides 46 percent of the steam cycle thermal input consisting of 88 percent of the plant economizing duty and 67 percent of the plant superheating duty. The PCFB boiler provides 44 percent of the steam cycle thermal input consisting of 93 percent of the reheating duty, 33 percent of the superheating duty, and 86 percent of the evaporating duty. The remaining 10 percent of the steam cycle thermal input is provided by the

- ash screw coolers in the form of condensate heating
- combustion air coolers in the form of economizing and evaporation
- gas turbine transition cooling in the form of steam reheat.

2.3 PLANT ARRANGEMENT

The following sections present the basis for and description of the arrangement recommended for the baseline plant.

2.3.1 Approach to Plant Arrangement/Layout

Criteria/constraints considered in the development of the plant arrangement were:

- Consideration of costly lengths of refractory-lined pipe, steam pipe, and electrical bus duct
- Access to the site by barge and rail
- Access to components/systems for-maintenance
- Adequate laydown space around components likely to be serviced in place
- Convenient access to plant where needed (e.g., ash transport truck routes, other service roads)
- Most components located above grade
- Enclosure of only those components requiring frequent attendance, in-place service, or other protection
- A safe working distance from the syngas flare system.

Using these criteria, the arrangements described in the next section were prepared. In subsequent studies, additional arrangements can be considered using the developed capital costs as a guide in comparing alternatives.

2.3.2 Plant Site Arrangement

The total site occupies approximately 180 acres, with the power island itself occupying approximately 3 acres. As in a pulverized coal (PC) fired plant, the smaller area occupied by the combustion equipment is overshadowed by the requirement to bring feedstocks into the plant and to provide interconnecting piping, access roads, parking, plant administration, and a reasonable working space between plant systems.

Overall Site Plan (Figure 2.3.2.1). The 2nd Gen PFB baseline plant is on a relatively level site adjacent to a navigable waterway, with both rail and highway access. The prevailing wind is from the southwest.

Coal and dolomite are delivered to the site by barge and then transported from the barge unloader to a transfer point by belt conveyor. During normal operation, coal or dolomite is delivered directly to the stacker/reclaimer conveyor, which is perpendicular to the barge unloader docking area. With the stacker/reclaimer in this position, the coal and dolomite storage area are located to the north of the main power island. If the stacker/reclaimer is inoperable at the time of barge delivery, coal or dolomite can be deposited directly in their inactive storage piles by emergency stackout conveyors. The coal pile shown is for about 30-days storage but only a nominal 14-day supply is maintained on hand. Coal and dolomite storage capacities can be increased up to 3 months, if required.

From storage, coal is sent to the crusher building at the west end of the stacker/reclaimer conveyor. It is crushed and conveyed to 24-hour storage silos at the east end of the power island. Coal from the silos is conveyed to the roller mills for final crushing, drying, and screening. This area also houses the lock hopper pneumatic transport feed systems. The dolomite (or limestone) storage silos are located nearby to the east, with short runs of conveyors feeding the sorbent to the feed trains.

Ash is mechanically conveyed to four ash storage silos on the east side of the power island. Ash is removed from the site by truck, using a dedicated ash haul road with an independent plant entrance. A truck scale along the haul road weighs ash trucks entering and leaving the site.

The gas turbine is located to the west of the PCFB boiler. The gas turbine discharge is ducted to the HRU on the west side of the gas turbine. The flue gas from the HRU is then ducted to a stack.

The steam turbine is south of the gas turbine. Generator leads exit both turbine buildings along the west wall. A common transformer area is located outdoors, west of the end of the combined gas/steam turbine building. From this area power is transmitted overhead to an adjoining substation. By positioning the gas and steam turbines as shown, a common transformer area is created, minimizing bus duct and transmission leads.

A rail spur services the turbine building, providing for heavy equipment installation and removal during and after plant construction.

A maintenance shop building at the southwest corner of the power island houses a laboratory and electrical, instrument, and machine shops.

A two-floor administration building adjacent to the turbine and maintenance buildings houses the plant access and locker room area at grade, with administrative offices on the second level. A parking area for plant personnel is south of the administration building.

A one-story structure located north of the power island structure houses water treating equipment. A building extension, at grade and to the north, houses the auxiliary boilers and emergency diesel generator.

A river water intake structure at the river's edge east of the power island building provides water to the cooling towers and to the makeup water and pretreatment building. In this building, river water is treated and stored awaiting use by the demineralized water system water treating building.

A multi-cell evaporative mechanical draft cooling tower is positioned to the south of the steam turbine building to minimize the length of circulating water piping that carries cooling water to and from the steam turbine condenser. Makeup water is pumped to the cooling towers from the intake structure. A structure adjacent to the cooling towers houses associated electrical switch gear and chlorination equipment. Truck access is provided for chemical delivery and circulating water pump maintenance.

A fuel oil storage tank, surrounded by an earthen dike south and west of the makeup water and pretreatment building, can be supplied with oil by either rail car or truck. A rail spur is provided for tank car shipments. A fuel oil pump house is east of the diked area. Oil piping can be carried back to the power island along a nearby pipe bridge.

A wastewater treatment facility is located north of the oil storage tank area. Wastewater retention ponds are positioned to the east, away from the main power island. Rainwater runoff from both the coal and dolomite storage piles is collected in these retention ponds and treated. Other contaminated water is also stored and treated for release.

A syngas flare stack is shown to the east of the oil storage tank in an isolated area of the site. An east-west pipe bridge connects the flare stack with the main pipe bridge on the power island.

Power Island--Plan at Grade (Figure 2.3.2.2). The Plan at Grade drawing provides additional detail and depicts equipment located at grade. It also shows equipment above grade in "phantom" lines.

Stair towers along the north and south side of the PCFB vessel bay provide access to the various floor levels of the coal preparation building as well as the PCFB vessel and carbonizer vessel. A phantom line outlines the various vessels that make up the steam generation modules above.

A single-story structure housing the plant main process and feed system air boost compressors sits directly to the north of the PCFB bay. The compressors are centrally located, as they serve the carbonizer, the coal and dolomite injection systems, and the filter back pulse system. The main process booster compressor takes air supply from the compressed air piping that is carried on the pipe bridge overhead. Also within this building are the PCFB start-up air heaters. A refractory-lined pipe connects the heaters to a compressed air line that supplies primary air to the PCFB. There are two boiler feedwater recirculation pumps below the PCFB vessel. Two bottom ash screw cooler are also located below the PCFB, and their discharge is pneumatically transported to the fly ash collecting hopper located under the PCFB filter vessels. Four screw coolers at grade and under these filter vessels further cool the ash. The cooled ash is discharged to a pneumatic conveying system, which conveys it to the west and discharges it to the ash silos.

A switchgear room is located south of the PCFB bay, in the electrical/control/admin building. The 480-V and 4160-V switchgear is housed in this area, providing power for the steam generation island as well as the coal preparation building.

The combined gas and steam turbine building is a high-roof configuration. A high bay over the turbines allows an overhead bridge crane to service the turbines. Each turbine has its own laydown space allocated nearby. There is truck access to both north and south walls of the power island, to move turbine components. An acoustical enclosure surrounds the combustion turbine and the topping combustors. The turbine air inlet directly north of the enclosure is positioned horizontally. The combustion turbine exhaust is ducted to the HRU, directly west of the turbine building, then to the stack. Transformers are in an area west of the turbine buildings, allowing for easy transmission of power to the substation. Power is returned from the substation to the two smaller auxiliary transformers shown to the west. These transformers power the 13.8-kV switch gear in the west end of the steam turbine building.

The steam turbine area lies directly south of the combustion turbine area. Rail access is provided at the southwest corner of the building with an equipment hatch above. The steam turbine has a two-flow, side-exhaust configuration, with “side-saddle” condenser units. This configuration does not require a deep excavation below the turbine, along with a high and massive pedestal. A pit housing the lube oil system is west of the turbine pedestal. The four boiler feedwater pumps, two mains and two boosters, are positioned farther to the east. The condensate pumps are shown on one side of the turbine.

The two bays east of the boiler feedwater pumps house the makeup water treatment and condensate demineralizer equipment. An acid and caustic truck unloading station is outside the east wall of the water treatment area.

The auxiliary boilers are housed in a single-story structure north of the turbine building. An emergency diesel generator is adjacent to the auxiliary boiler building. The demineralized water storage tank is between the auxiliary boiler and plant access road to the east.

The grade level plan shows an area in the administration building reserved for plant access control and shower/locker rooms. A room in the southeast corner of the building houses the heating, ventilating, and air conditioning (HVAC) equipment required to condition the air in the administration building and the control complex area.

A stair tower and elevator in the northeast corner of the administration building serve both the administration and the turbine building/control complex areas. A stair tower in the southwest corner of the administration building provides a second means for reaching or leaving the second floor.

Power Island-Auxiliary Plans Above Grade. Figure 2.3.2.3 provides a series of auxiliary plan views showing equipment arrangement at the following elevations: 128’-6” and 137’-0”, 180’-0” and 191’-0”, 201’-0” and 247’-0”, and 303’-0” and 321’-0”. Each auxiliary plan represents two discrete elevations, as noted. The top two elevations are only shown for most but not all of the structure; the part of the structure housing the coal preparation equipment only rises to a final floor elevation of 247’-0” with the roof at approximately 275’-0”.

The auxiliary plans start at the bottom of the tall structure housing the PCFB boiler, carbonizer, filters, and coal preparation vessels and piping. This structure is comprised of 32 bays, each nominally 25 feet square. For each plan, starting at the east end of the structure, eight bays (two by four) house the coal crushing and drying equipment and piping. This includes the mills or crushers at the lowest elevation (grade), with silos, day bins, cyclone separators, etc. arranged above at elevations to provide a continuous flow path for the coal as it is crushed and dried.

The second group of eight bays houses the carbonizer and its hot gas filters, ash hoppers, etc. The third group of eight bays houses the PCFB boiler. The final group of eight bays houses the hot gas filters serving the PCFB, along with the ash collection vessels.

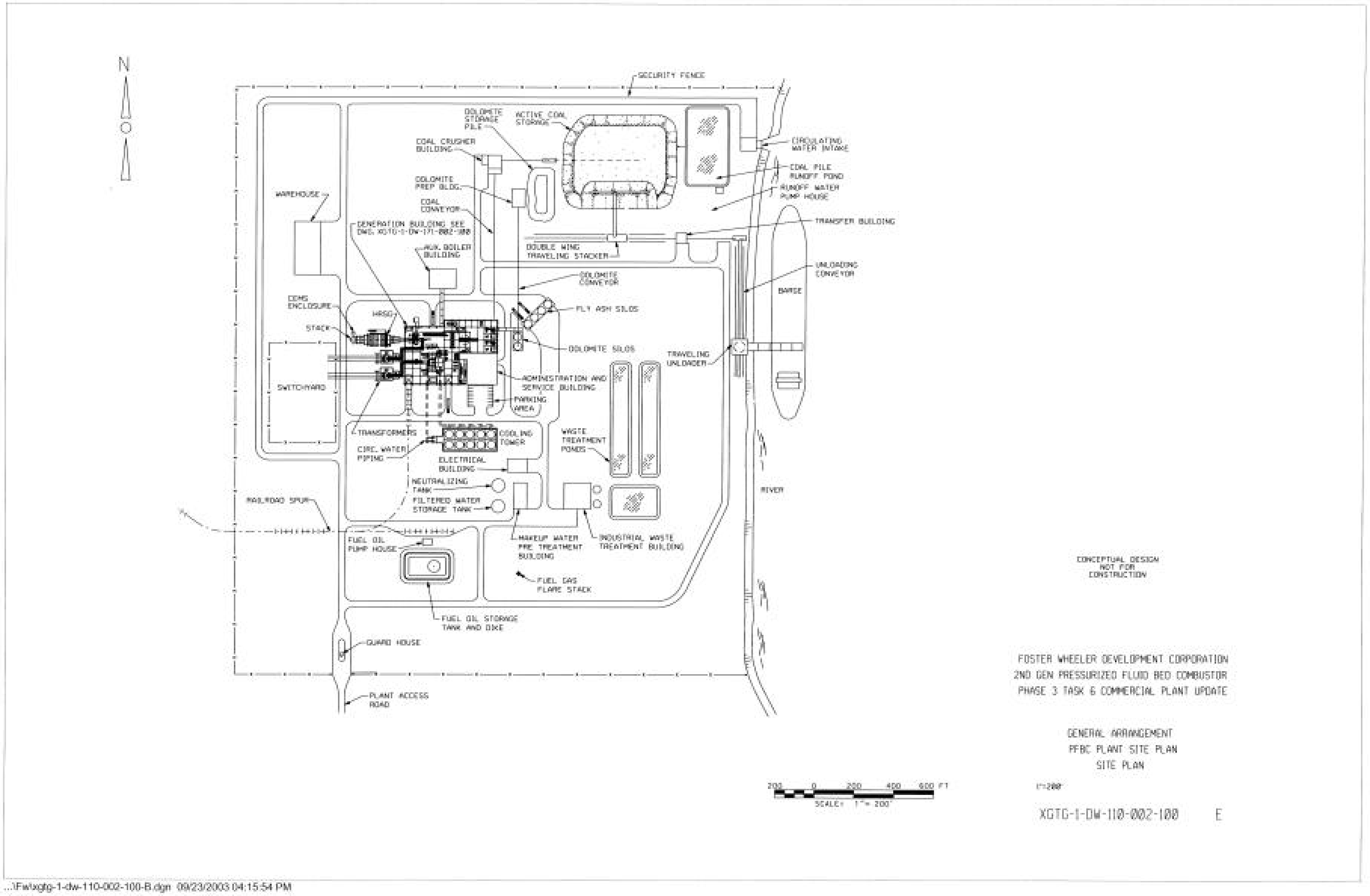

Figure 2.3.2.1 Site Plan

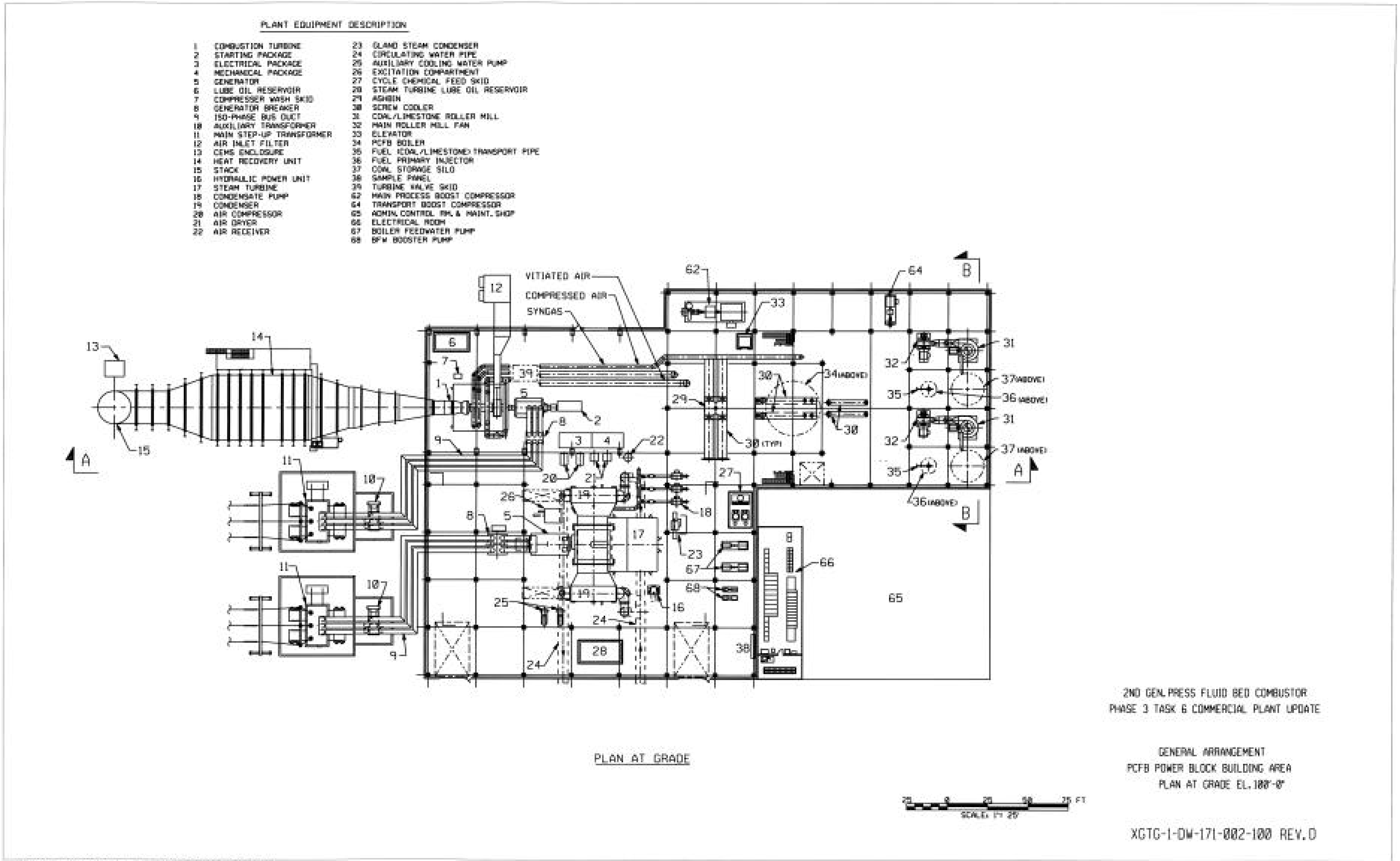

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Figure 2.3.2.2 Plan at Grade

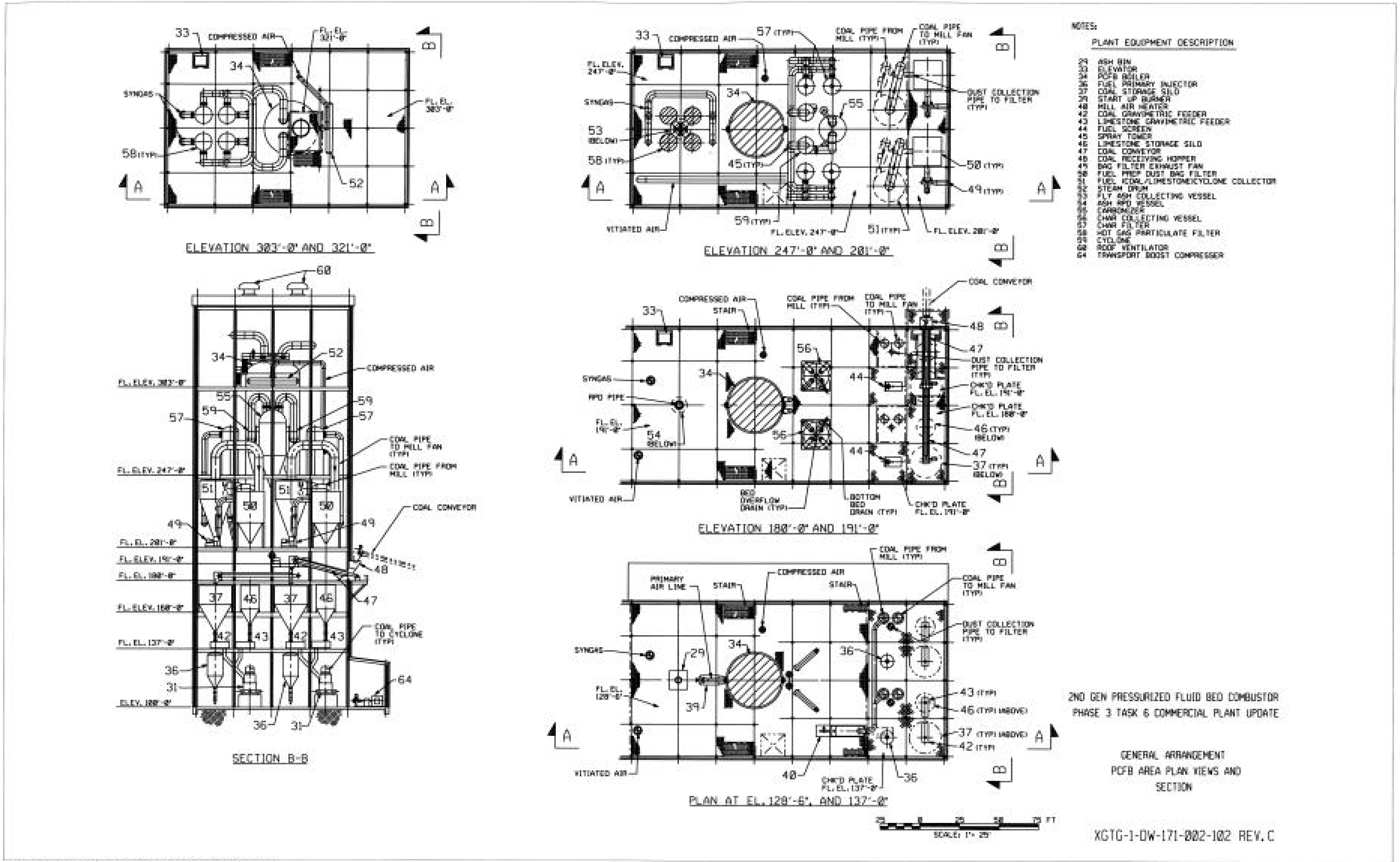

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Figure 2.3.2.3 Auxiliary Plans Above Grade

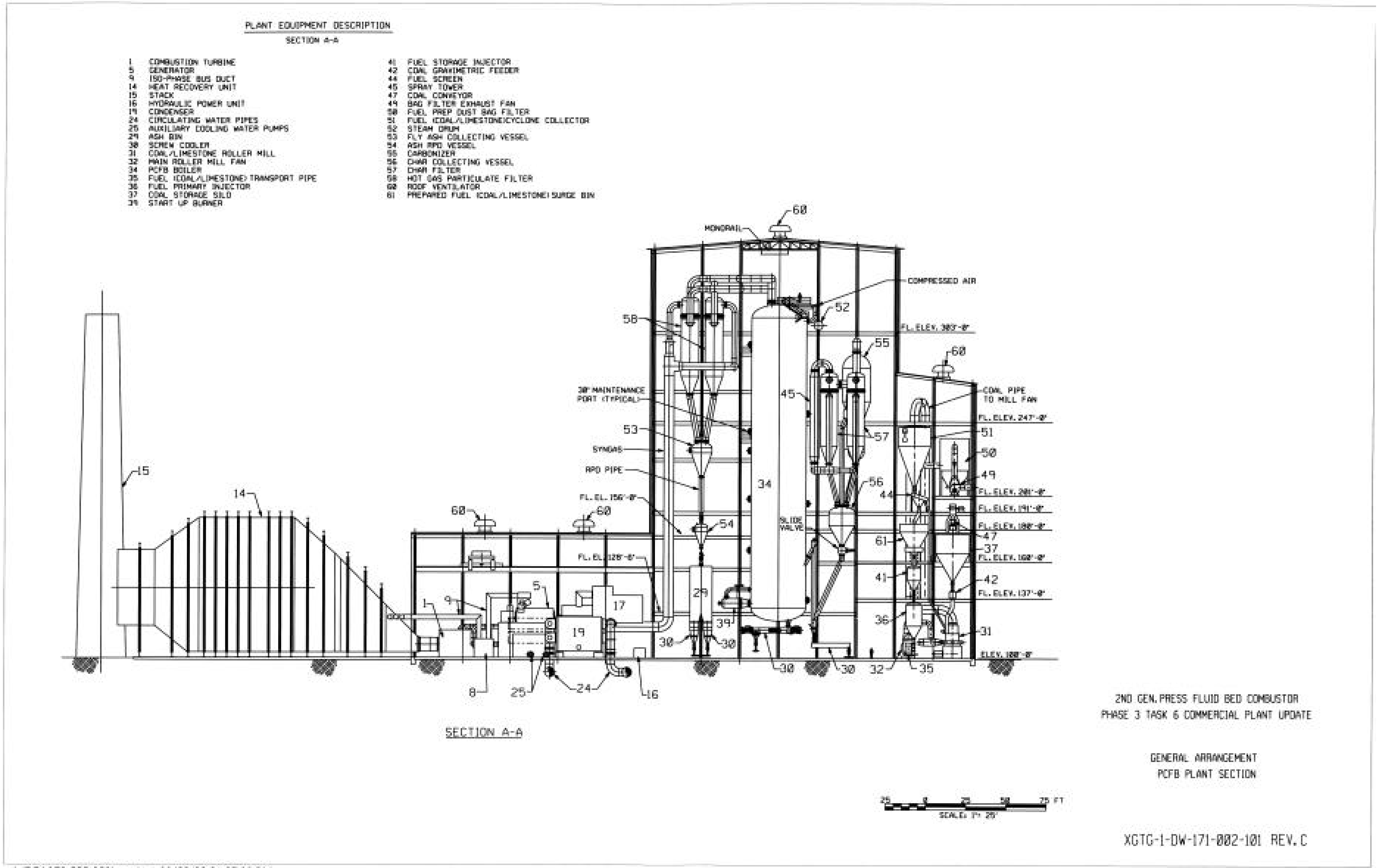

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Figure 2.3.2.4 South to North Section

Power Island-Sections. Section AA on Figure 2.3.2.4 shows a longitudinal section of the power island from south to north, and from grade up to the roof line. The section spans the entire structure from the stack to the coal preparation bays on the east.

Section BB on Figure 2.3.2.3 shows a transverse view from east to west. The view is taken at the east end of the structure, and thus shows the coal preparation equipment in detail, with other equipment revealed behind as appropriate for the view.

2.4 PLANT PERFORMANCE

The performance of the overall baseline plant is presented in this subsection; detailed component performance data are presented in Section 2.5, along with physical descriptions of the components.

2.4.1 Approach

Plant performance was calculated by representing the overall plant cycle with the ASPEN Plus Process Simulation Program (ASPEN). This code produces an overall heat and mass balance for the PCFB system, the gas turbine, the HRU, and the steam turbine; in addition it calculates auxiliary electric powers for major motor-driven components in the flow streams, such as booster compressors and pumps. Information from the ASPEN simulation was used to prepare the heat and mass balance diagram and to calculate overall plant performance by transmitting state-point data calculated by ASPEN to a computer-aided design and drafting (CADD) system, allowing preparation of the system heat and mass balance with minimal human interface and reducing the chance for errors in state-point data.

Pressure drops and heat losses were calculated for the major equipment in the carbonizer, PCFB, and gas cleanup systems. The baseline plant performance analysis includes/accounts for:

- Calculated system heat losses and pressure drops
- Correction of the carbonizer heat balance for transport air and heat losses
- Correction of gas turbine power and exhaust gas condition for pressure losses in the air distribution, PCFB, and cleanup systems
- Three steam extractions for condensate heating rather than one
- Ash cooler heat for condensate heating
- Representation of transport air requirements and air losses in the cycle
- Calculation of plant air and power auxiliary requirements.

2.4.2 Results

At the full-load design point, all coal and sorbent are fed to the carbonizer, whereas at part load and startup, coal and sorbent are also fed to the PCFB boiler. Table 2.4.2.1 shows the overall performance for the power plant at full load. Net power for the baseline plant is 477.52 MWe, with a net plant efficiency of 48.0% HHV based on the higher heating value of the fuel.

The breakdown of auxiliary power requirements also appears in Table 2.4.2.1. These power requirements are calculated from the flow and head requirements for pumps and compressors in the major process flow streams in the plant. Auxiliary requirements for secondary flow streams, such as coal handling or ash handling, are calculated from the motor powers and duty factors for those systems. Auxiliary requirements for the service water system and for miscellaneous uses (lighting, HVAC, controls and computers, shop and instrument air, etc.) are based on the rate of coal feed to the plant.

A tabulation of the input and output streams crossing the plant boundary appears in Table 2.4.2.2. This tabulation is useful for identifying the major energy losses in the power plant cycle and also for verifying the validity of the power cycle performance estimate.

As shown in Figure 2.2.0.2 (heat and mass balance diagram for the plant), flows and powers correspond to total quantities for the entire plant.

Table 2.4.2.1 Overall Performance of Baseline Plant at Full Load

Total Plant Coal Feed to Carbonizer/PCFB Boiler,%	100/0
Power Summary, kWe	
Gas Turbine Power	239,500
Steam Turbine Power	258,957
Gross Power	498,457
Auxiliaries	(20,935)
Net Power	477,522
Net Efficiency,% (HHV)	48.0
Net Heat Rate, (HHV)	7,105
Consumables and Wastes:	
As-Received Coal Feed, lb/h (6.0% moisture)	272,406
As-Fired Coal Feed, lb/h (2.5% moisture)	262,627
Dolomite Feed, lb/h	78,864
Ash Production, lb/h	98,369
Coal and Dolomite Drying Fuel, gal/h	94
Auxiliary Summary, kWe:	
Filter Boost Compressor	350
Transport Booster Compressor	420
Main Booster Compressor	7,560
Condensate Pumps	390
Feedwater Pumps	4,060
Boiler Forced-Circulation Pumps	600
Circulating Water Pumps	2,150
Cooling Tower Fans	1,600
Fuel Gas Recycle Blower	100
Coal Dryer Induced-Draft Fan	250
Gas Turbine Auxiliaries	300
Steam Turbine Auxiliaries	300
Nitrogen Supply	---
Barge Unloading and Stacker/Reclaimer	170
Coal Handling	350
Dolomite Handling	70
Coal and Sorbent Feed	30
Ash Cooling and Handling	100
Miscellaneous	1,000
Step-Down Transformer Loss	1,100
Total Auxiliaries	20,900
Cooling Tower Loads, 10^6 Btu/h:	
Condenser	1270
Open Cycle Cooling System	22
Total Cooling Duty	1292

Table 2.4.2.2 Input and Output Streams Crossing Plant Boundary (Baseline Plant, Rev. D)

Description	**Flow, lb/h**	**Temperature E F**	**Enthalpy, Btu/lb**	**HHV, Btu/lb**	**Power, kWe**	**Energy, 10^6 Btu/h**
Inputs:						
Carbonizer Coal	274,200	---	---	---	---	---
PCFB Coal	---	---	---	---	---	---
Total Coal	274,200	150.0	35.70	12,916.0	---	3551.36
Sorbent Feed	82,315	77.0	7.93	---	---	0.65
Calcination	---	---	---	---	---	(53.41)
Sulfation	---	---	---	---	---	48.09
Gas Turbine Inlet Air	6,660,000	60.0	15.71	---	---	104.63
Transport Compressor	---	---	---	---	447	1.53
Condensate and Feedwater Pumps	---	---	---	---	5,632	19.22
Forced-Circulating Pumps	---	---	---	---	315	1.08
Total Inputs	7,016,515					3673.15
Outputs:						
Gas Turbine Generator Output	---	---	---	---	195,150	666.05
Gas Turbine Generator Loss	---	---	---	---	5,004	17.08
Gas Turbine Radiation Loss	---	---	---	---	---	3.02
Steam Turbine Generator Output	---	---	---	---	272,338	929.49
Steam Turbine Generator Loss	---	---	---	---	5,204	17.76
Fan and Pump Motor Loss	---	---	---	---	220	0.75
Turbine Cooling Air Intercooler Loss	---	---	---	---	---	22.22
Booster Intercooler	---	---	---	---	---	12.75
Booster Intercooler Condensate	430	100.0	68.54	---	---	0.03
Carbon Loss	789	300.0	57.57	14,087.0	---	11.16
Ash Loss	---	---	---	---	---	5.20
HRU Stack	6,879,269	280.0	88.36	---	---	607.85
Lost Air and Gas						
Transport Compressor Loss	45,166	175.9	37.95	---	---	1.71
Ash Lock Hopper Blowdown	500	1050.0	269.91	---	---	0.13
Transport Air Heat Loss	---	---	---	---	---	0.22
G/C Scope Hot Gas Piping	---	---	---	---	---	10.75
Carbonizer and Fuel Clean-Up Loss	---	---	---	---	---	7.92
PCFB and Cyclone Loss	---	---	---	---	---	21.10
PCFB Candle Filter	---	---	---	---	---	6.03
Condenser	---	---	---	---	---	1322.20
HRU Radiation	---	---	---	---	---	12.63
Total Outputs	7,016,509					3676.06
Unaccounted for, lb/h	6					0.30
Unaccounted for,%	0.00					0.01

2.4.3 Design Issues and Approaches

This subsection describes baseline plant design approaches and compares them to those used in an earlier Phase 1 study. The baseline case serves as a reference for the economics analysis presented in Section 3, the emissions estimates presented in Section 4, and the sensitivity studies presented in Section 6.

The baseline configuration used in the Phase 1 study utilized two nominally 100 MWe Westinghouse 501D type gas turbines together with two 1500EF carbonizers, two 1600E PCFB boilers, and one steam turbine.

The present baseline plant is based on a single nominally 240 MWe Siemens-Westinghouse 501G gas turbine coupled with a single carbonizer, PCFB boiler, and steam turbine. The carbonizer operates at 1700EF. The different carbonizer temperature results in a higher level of syngas production, which is necessary to support the higher firing temperature of the 501G machine relative to that of the 501D (2700EF vs. 2150EF, nominal values). The 501G machine incorporates steam cooled burner to turbine inlet nozzle transition ducts, which provide a portion of the steam turbine reheat duty (cold reheat to hot reheat). The topping combustor for the gas turbine in both plants utilizes rich quench-lean burn MASBs to minimize NOx formation.

The current baseline design incorporates a main/process air boost compressor (discussed in Section 2.5.14) to compensate for the increased gas side pressure drop associated with the carbonizer and PCFB boiler flow paths relative to that occurring in a natural gas or distillate fueled gas turbine. The boost compressor maintains gas path conditions at the expander inlet nozzle very close to natural gas design conditions, preventing compromises to system output, compressor surge margins, etc. The original W501D based design did not incorporate a boost compressor, and a reduced gas turbine power output caused by a lower hot gas expansion ratio was utilized.

The present baseline plant uses a 2400 psig/1050EF/1050EF steam cycle in lieu of the 2400 psig/1000EF/1000EF of the earlier study. Current practice is tending towards the higher steam temperatures, which lead to higher efficiencies with essentially no added risk. The steam turbine configuration selected for the current report is based on similar machines now in service in combined cycle systems. This type of machine is designed to pass more flow through the low pressure section than a machine configured for conventional pulverized coal service. The abundance of heat recovery in the gas turbine exhaust in the PFB cycle has the same impact as in a typical combined cycle application.

In the Phase 1 study, the coal and dolomite were fed via separate lock hopper feed systems; similarly, the PCFB boiler bottom ash and fly ash were depressured via separate lock hoppers and the ash transferred to separate silos. For cost savings, the baseline plant now feeds the coal and dolomite as a blend (for clarity purposes the plant heat and mass balance diagrams show them as separate feed streams). In addition PCFB boiler bottom ash and fly ash streams are combined for depressuring as a single stream and ultimate storage in common silos. Since lock hopper type feeding of blends has been successfully demonstrated in 1st Generation PFB Combustion Plants and since combining coarse bottom ash with fine fly ash should improve material handling characteristics, these cost saving changes should not introduce risks to the plant design. With regard to the drying of the coal and dolomite, both plants accomplish this in combined crushing-drying systems using hot flue gas extracted from the gas turbine exhaust.

2.4.4 50 Percent Load Operation

Baseline plant performance was determined at nominal 50 percent load; at this point, the plant coal flow rate and net electrical output drop to 62 and 55 percent respectively of their full-load values. Approximately 15 percent of the reduced plant coal flow is fed directly to the PCFB boiler. The thermal duty of the carbonizer, the gas turbine topping combustor, and the char residue production rate are reduced at this load, while the thermal duty of the PCFB associated with heating the oxidant for the topping combustor and supplying heat to the steam cycle are reduced by a smaller amount.

The following assumptions were made in establishing the 50 percent load performance point:

- PCFB boiler flue gas exit temperature is allowed to fall to 1550EF.
- Carbonizer air/coal ratio remains constant.
- Gas turbine air flow is reduced by 27 percent by the inlet guide vanes.
- Steam turbine throttle pressure and temperatures remain constant.
- Carbonizer and PCFB boiler operating pressures are allowed to float with the gas turbine operating pressure.

Figure 2.4.4.1 presents a heat and mass balance for the plant at 50 percent load. Table 2.4.4.1 summarizes key operating parameters and compares them with full load values. Some of the significant changes from the full-load point are:

- Gas turbine compressor discharge pressure and temperature and all other system gas-side pressures are reduced because of the lower gas turbine airflow and the reduction in firing temperature.
- Coal feed to the carbonizer drops to about 53 percent of the full-load value because of the reduction in the gas turbine firing rate.
- Carbonizer and PCFB exit temperatures drop by 13EF and 50EF respectively.
- Carbonizer fluidizing velocity decreases by about 24 percent because the reduction in system pressure tends to offset the reduction in firing rate.
- PCFB velocity decreases by about 5 percent since the reduction in system pressure is greater than the decrease in PCFB mass flow and temperature.

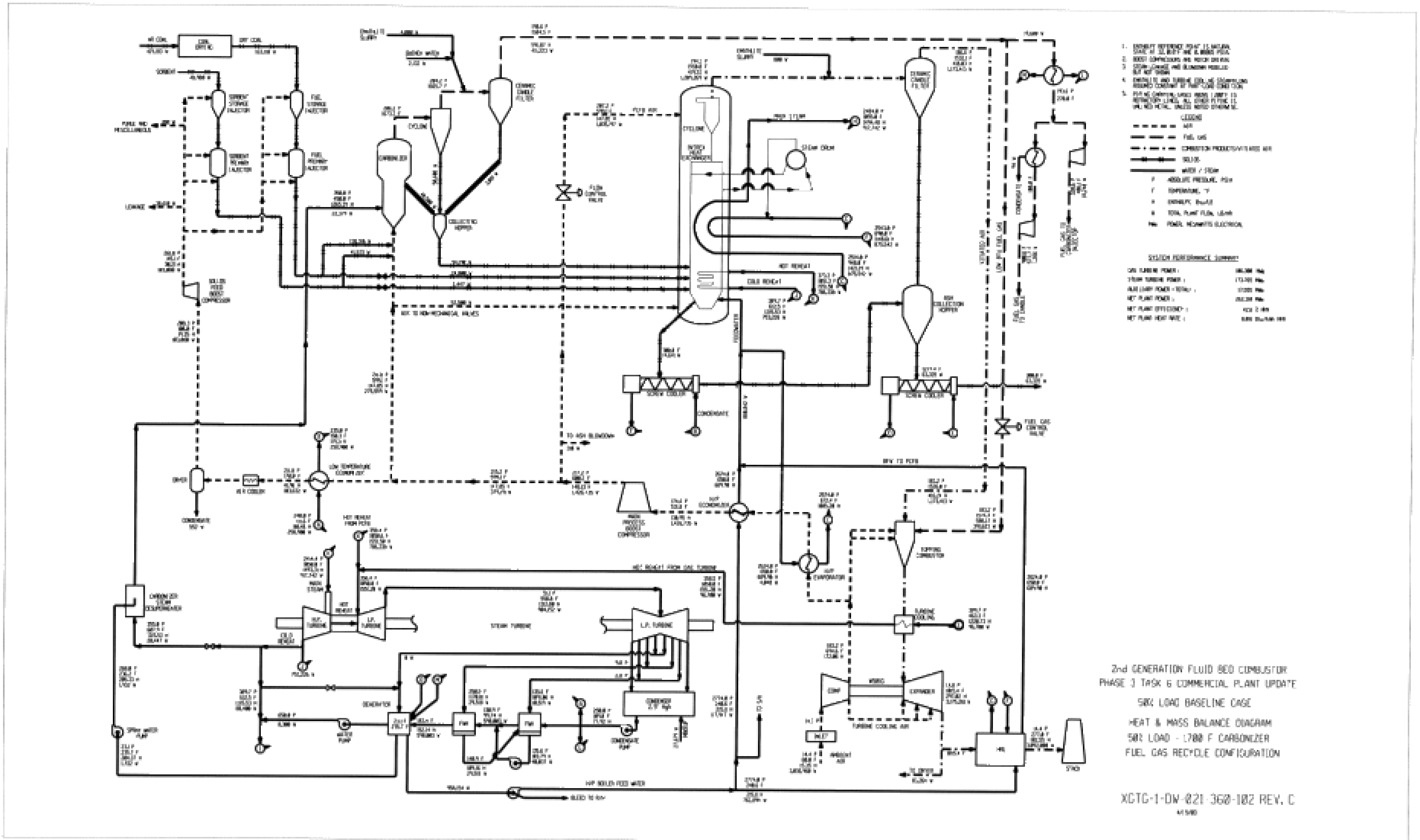

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Figure 2.4.4.1 50 Percent Load Heat and Mass Balance

Table 2.4.4.1 Comparison of Baseline Plant Performance at Full and Minimum Load

Category	Full Load	50% Load
Power Summary:		
% of Total Plant Coal Flow to:		
Carbonizer	100	85
PCFB boiler	---	15
Gas Turbine Power, kWe	239,500	106,300
Steam Turbine Power, kWe	258,957	173,765
Gross Power, kWe	498,457	280,065
Auxiliaries, kWe	(20,935)	(17,185)
Net Power, kWe	477,522	262,880
Net Efficiency, % (HHV)	48.0	42.6
Net Heat Rate, (HHV)	7,105	8,016
Consumables and Wastes:		
As-Received Coal Feed, lb/h (6.0% moisture)	272,406	169,183
As-Fired Coal Feed, lb/h (2.5% moisture)	262,627	163,110
Dolomite Feed, lb/h	78,864	48,980
Ash Production, lb/h	98,369	63,335
Operating Parameters:		
Carbonizer Coal Feed, % of design	100.0	52.7
Carbonizer Fluidizing Velocity, % of design	100.0	75.0
PCFB Fluidizing Velocity, % of design	100.0	94.0
Carbonizer Exit Temperature, EF	1686	1673
PCFB Exit Temperature, EF	1600.0	1550.0
Gas Turbine Firing Temperature, EF	2690	2360

2.5 SYSTEM/COMPONENT DESCRIPTION AND PERFORMANCE

2.5.1 Coal-Handling System

System Functions. The main functions of the coal-handling system are to unload coal from barges and convey it to the coal storage pile area; pile, reclaim, crush, and sample it; convey it to the in-plant storage silo (bunker); and from there, convey it to the lock hopper systems, which feed the carbonizer and PCFB boiler.

Design Considerations and Requirements. The coal-handling system design requirements include:

- A coal-handling system designed to unload and pile 2-in. x 0 eastern bituminous coal in the yard stockpiles at a normal maximum rate of 3000 t/h and an average rate of 2500 t/h. The average rate will permit unloading almost 14,000 tons of coal in 5-1/2 hours from 7100-dead weight ton (DWT) open-top steel barges, using a continuous bucket-elevator-type barge unloader.

- Unloaded coal is conveyed to a coal pile storage area at the northeast end of the plant. The conveying system is designed to convey coal at a maximum rate of 3300 t/h, which is 10 percent faster than the normal maximum unloading rate of 3000 t/h to allow for overfilling buckets during barge unloading.

- A storage area with an active storage pile for the plant is provided to meet these conditions:

  - A 100,000-ton storage pile capable of supplying coal for 30 days to the plant when it is operating at 100 percent capacity. It is formed by piling all 100,000 tons of coal on the east side of the yard conveyor.
  - An emergency conveyor to continue unloading barges in the event the primary piling system is out of service or the bucket-wheel reclaimer is being used. The conveyor can pile 10,000 tons atop the inactive storage pile before bulldozing is required.
  - An emergency reclaim system with active reclaim capacity of 8000 tons without any bulldozing required.

- A redundant reclaim system ensures an uninterrupted and reliable coal supply to the bunkers. Coal is reclaimed at a normal rate of 800 t/h from either the primary reclaim system (stacker/reclaimer) or from the emergency reclaim system. A 100% redundant coal-handling system is also provided from the surge bin outlet to the lock hopper injection system bunkers. Because double crushing is required to reduce the 2-in. coal to 1/8-in., crushing operations are segregated upstream and downstream of the silo. This separation allows a substantially smaller crusher building and a more compact system layout. A substantial reduction in horsepower is also achieved.

  - Reclaimed coal (2 in. x 0) is conveyed at 800 t/h via the 200-ton surge bin and primary crushers to a 10,200-ton coal storage silo. This silo provides 3 days of 1/2-in. x 0 coal storage and eliminates reclaim work on weekends. The silo can be filled in 13 hours.

- The 1/2-in. x 0 coal stored in the 3-day silo is fed twice during each daylight shift into a 3400-ton 24-hour storage silo (bunker). Each filling takes 130 minutes.
- The 1/2-in. x 0 coal stored in the silo (bunker) is continuously conveyed by totally enclosed belt wall conveyors through crushers, dryers, and coal screens to three 20-ton surge bins at 142 t/h. In the process it is reduced to 1/8 in. x 0 and dried. Totally enclosed belt wall conveyors were selected to reduce the amount of coal dust and fire hazards associated with dried coal. This type of conveyor also allows high-incline or vertical runs in a minimum of space. Even though this type of conveyor requires more maintenance than flat belt conveyors, it was chosen because it is dust-tight.
- Coal is released from the 20-ton storage bins to the lock hopper feed systems.

Major Equipment Descriptions. Figure 2.5.1.1 is a simplified schematic of the coal handling system and descriptions of the major components are presented in Tables 2.5.1.2 through 2.5.1.4. Portions of the coal-handling system equipment are also used for dolomite handling. Primarily, these include the barge unloader, bucket-wheel stacker/reclaimer, and associated conveyors. Shared items are identified by the "dual use" designation in Section 2.5.2.

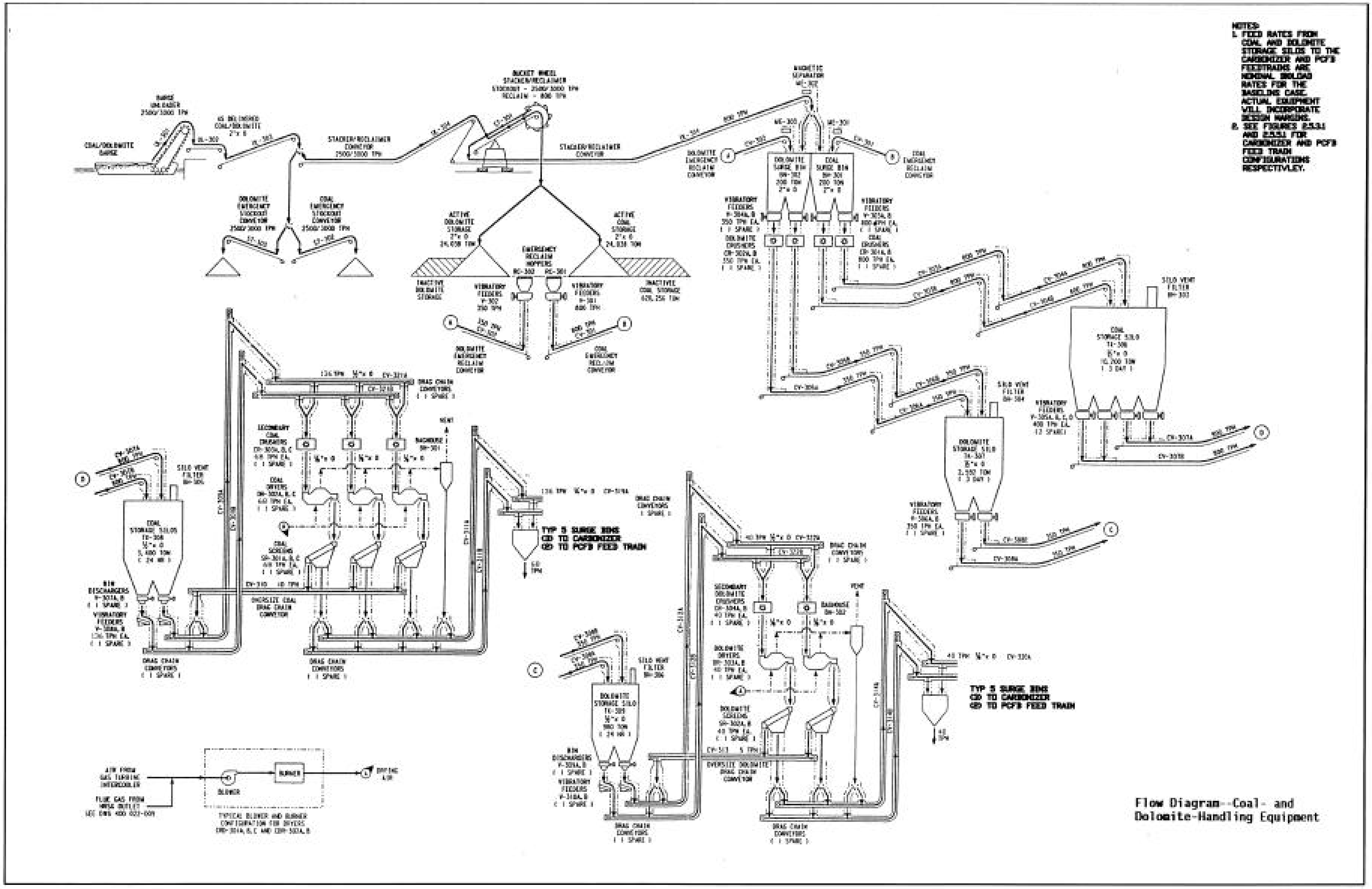


Figure 2.5.1.1 Coal-Dolomite Handling Schematic

2.5.2 Dolomite-Handling System

This section describes the dolomite-handling system, including the system function, design requirements, and major equipment.

System Functions. The main functions of the dolomite-handling system are to unload dolomite from barges; convey it to the dolomite storage pile area; pile, reclaim, crush, and sample it; and convey it via the in-plant dolomite storage silo (bunker) to the lock hopper feed systems, which supply the carbonizer and PCFB boiler.

Design Requirements. The dolomite-handling system design includes:

- A dolomite-handling system designed to unload and pile Plum Run dolomite, in a size range of 2 in. x 0, to the yard stockpiles at a normal maximum rate of 3000 t/h, with an average rate of 2500 t/h. This rate will permit unloading 15,000 tons of dolomite within 6 hours from 7100-DWT open-top steel barges, using a continuous bucket-elevator-type barge unloader.

- Unloaded dolomite conveyed to a dolomite pile storage area at the west end of the coal pile. The conveying system is designed to convey dolomite at a maximum rate of 3300 t/h, 10% faster than the normal maximum unloading rate of 3000 t/h to allow for overfilling the bucket during the barge-unloading operation.

Table 2.5.1.1. Coal- and Dolomite-Handling Equipment

Description	Tag No.	Quantity Required	Dimensions/Operating Data
Barge Unloader	UL-301	1	
Free Digging Rate			3000 t/h
Average Unloading Rate			2500 t/h
Barge Capacity			7100 DWT (max.) 2000 DWT (min.)
Barge Size			40-66 ft wide x 345 ft long
Unloading Cycle Time for Two Barges (Two passes per barge)			340 min
Barge Haul Systems:			
Receive Loaded Barge		1	
Unload Loaded Barge		1	
Park Unloaded Barge		1	
Bucket Elevator (Single Line):			4-ft intervals
Bucket Capacity			75 ft^3/bucket
Bucket Speed			148 ft/min
Bucket Elevator Motor			350 hp: totally enclosed, fan-cooled (TEFC): 1750 rev/min: 4000 V: three-phase: 60 Hz: 1.15 safety factor: Class B insulation
Barge Positioner (hydraulic)			15 hp: 120 V: three-phase: 60 Hz
Barge Haul Motor		2	20 hp: 725 rev/min: continuous 230-V dc. shunt wound Type MDP: Class H insulation)
Capstan Motors		2	15 hp: 1800 rev/min: 460 V: 3-phase: 60 Hz
Conveyor (Gathering)	UL-302		
Belt Speed			525 ft/min
Belt Capacity			3300 t/h
Trough Idlers			35 deg -6 in.: CEMA E6
Return Idlers (Rubber Disc)			CEMA 6
Take-Up			Gravity (enclosed)
Drive			100 hp: TEFC: 1750 rev/min: 460 V: 3-phase: 60 Hz
Belting			72-in., 4-ply polyester reinforcing with 1/4-in. top cover, 3/32-in. bottom cover
Belt Conveyors			See Table 12
Chain Conveyor			See Table 13
Magnetic Separator			
Conveyor (Discharge)	UL-304A	1	
Drive			7 hp
Magnet			11.88 kWe
Conveyor (Discharge)	CV-301A	1	
Drive			3 hp
Magnet			6.171 kWe

Table 2.5.1.1 (continued). Coal- and Dolomite-Handling Equipment

Description	Tag No.	Quantity Required	Dimensions/Operating Data
Crushers			
Primary Coal Crushers	CR-301A and B	2	
Capacity			800 t/h each
Motor			450 hp. 720 rev/min. 4000 V
Coal Input			2 in. x 0 in.
Coal Output			3/4 in. (Nominal 1/2 in.)
Coal Reduction			4:1
Secondary Coal Crushers	CR-303A. B. and C	3	
Capacity			71 t/h each
Motor			50 hp; 1800 rev/min; 460 V
Coal Input			3/4 in. (Nominal 1/2 in.)
Coal Output			-1/8 in.
Coal Reduction			4:1
Sampling Systems			
"As-Received" Sampling System			Three-stage. automatic proportional for 38-lb samples. with crusher. collector bin. and feeder belts
"As-Fired" Sampling System			Two-stage. incremental method with crusher. sample collector bin. and feeder belts
Vibration Feeders			
Vibration feeders used in the Coal-Handling System are presented in Table 14.			
Flop-Gate Actuators		3	
Shut-Off Gate		2	
Location			200-ton surge bin BN-301A outlet to Crushers CR-301A and B
Manufacturer			Process Equipment Builders. Inc.
Sump Pumps			
Location			Crusher building/reclaim tunnel
Type			VN (vertical slurry pump)
Air Dryer			
Location			Crusher building. Transfer Building 1: Emergency: Reclaim
Manufacturer			Deltech Engineering. Inc.
Type			G Series. heatless dryers
Belt Cleaners			
Location			Head pulley. all conveyors
Belt Scales With Integrator			
Location			Conveyor UL-303. Conveyors CV-303A and B
Accuracy			1/4 of 1 percent
Capacity Range			Conveyor UL-303: 800-4000 t/h Conveyors CR-303A and B: 250-1500 t/h

Table 2.5.1.1 (continued). Coal- and Dolomite-Handling Equipment

Description	Tag No.	Quantity Required	Dimensions/Operating Data
Telescopic Chute	TC-301A		
Location			Discharge of Conveyor ST302A
Air Compressor			
Location (1)			Barge unloader
Location (2)			Transfer Building 1
Stacker/Reclaimer		1	
Type			Slewing-bucket wheel stacker/reclaimer
Capacity			
Stackout			3300 t/h stacking (max.)
Reclaim			425, 600, and 800 t/h; Average 1200 t/h overload during reclaim
Bypass			0-850 t/h
Storage			24,040 tons active storage, 50-ft-high pile 134 t/ft at 50 lb/ft³
Travel Distance			330 ft reclaiming; 268 ft-2 in. stacking; 5 ft-0 in. overtravel
Boom Operating Angles			15 deg above horizontal; 13 deg below horizontal; 90 deg from and when stacking; 71 deg from and when reclaiming
Travel Speed			50 ft/min
Bucketwheel			20 ft-0 in. diam with 8-14 ft³/bucket cell-less
Buckets			Driven by 75 hp TEFC 1800 rev/min; 460 V; 3 phase; 60 Hz motor
Boom			108-ft long slow pivot to centerline of bucketwheel
Bucket Conveyor			
Belt Speed			565 ft/min.
Belt Capacity			3300 t/h (max.)
Trough Idlers			350 ft-6 in. - CEMA E6
Impact Idlers			7-1/2 x 2-1/2 in.; 0 pressure
Return Idlers			Rubber disc 6-in. CEMA E6
Conveyor Length/Rise			113-ft/approximately 30 ft. max.
Takeup			Manual screw
Drive			200 hp; 1800 rev/min; TEFC; 460 V; 3-phase; 60 Hz
Belting			72-in. 1-ply (steel cable) with 1/4-in. top cover and bottom cover; SCOF
Luffing Drive			
Operating Pressure			1500 psig (max.)
Number of Cylinders			2 (10-in. diam x 14 ft-6 in. stroke)
Power Pack			2 10-hp units (10 operating), spare
Moving Gear			
Travel Driven Motors			7.5 hp; 1200 rev/min; TEFC; 460 V; 3-phase; 60 Hz
Slew Drive Assembly			
Number of Drives			2
Drive Motor			2 - 15 hp; 1750 rev/min; shunt wound dc
Lubrication			Automatic and centralized
Splitter Device			Hydraulic-operated chute

Table 2.5.1.2 Coal-Dolomite Handling Belt Conveyors

Description	UL-303	ST-303	UL-304	CV-302	CV-305A/B	CV-306A/B	CV-308A/B
Function	Conveys coal from barge unloader conveyor to Transfer Building 1	Emergency stacking conveyor Transfer Building 1 to inactive storage pile	Yard conveyor, Transfer Building 1 to crusher building via stacker/reclaimer	Underground reclaim conveyor from emergency reclaim pile to crusher	Conveyors from crusher building to Conveyors CV-306A and B	Transfer material from Conveyors CV-305A and B to Dolomite Storage Silo TK-307A (3 day)	Transfer material from (3 day) Storage Silo TK-307A to (1 day) Storage Silo TK-309A
Quantity	1	1	1	1	2	2	2
Belt Speed, ft/min	525	525	525	520	410	410	410
Maximum Belt Capacity, t/h	3300	3300	3300	800	350	350	350
Trough Idler	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6
Impact Idlers	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6	35 deg-7 in. CEMA E6	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6
Return Idlers	Rubber disc--6 in. CEMA E6	Rubber disc--6 in. CEMA E6	Rubber disc--7 in. CEMA E6	Rubber disc--7 in. CEMA E6	Rubber disc--6 in. CEMA E6	Rubber disc--6 in. CEMA E6	Rubber disc--6 in. CEMA E6
Conveyor Rise/ Length, ft	52/200	50/220	95/1100	101/390	35/250 (approximately)	78/750	80/605
Takeup	Enclosed gravity double reeved	Gravity (enclosed)	Gravity (enclosed)	Gravity (enclosed)	Gravity	Screw-manual	Screw-manual
Drive	700 hp, 1200 rev/ min, 4000 V, 3-phase, 60 Hz, with fluid coupling backstop, and reducer	500 hp, 1200 rev/ min, 4000 V, 3-phase, 60 Hz with Voith fluid coupling backstop and reducer	500 hp, 1200 rev/ min, 4000 V, 3-phase, 60 Hz with fluid coupling backstop and reducer	200 hp, 1800 rev/ min, 460 V, 3-phase, 60 Hz with coupling backstop and reducer	20 hp, 1800 rev/ min, 460 V, 3-phase, 60 Hz with coupling backstop and right angle	45 hp, 1800 rev/ min, 460 V, 3-phase, 60 Hz with reducer	50 hp, 1800 rev/ min, 460 V, 3-phase, 60 Hz with coupling backstop and reducer
Belting	72 in. 3-ply, polyester reinforcing with 3/16 in. top cover, 3/32 in. bottom cover, MSHA, SCOF, fire resistant	72 in. 4-ply, polyester reinforcing with 3/16 in. top cover, 3/32 in. bottom cover, MSHA, SCOF, fire resistant	72 in. 4-ply, polyester reinforcing with 3/16 in. top cover, 3/32 in. bottom cover, MSHA, SCOF, fire resistant	42 in. 4-ply, polyester reinforcing with 3/16 in. top cover, 3/32 in. bottom cover, MSHA, SCOF, fire resistant	30 in., 3-ply, polyester reinforcing with 3/16 in. top cover, 3/32 in. bottom cover, MSHA, SCOF, fire resistant	30 in., 3-ply, polyester reinforcing with 3/16 in. top cover, 3/32 in. bottom cover, MSHA, SCOF, fire resistant	30 in., 3-ply, polyester reinforcing with 3/16 in. top cover, 3/32 in. bottom cover, MSHA, SCOF, fire resistant

Table 2.5.1.3 Coal-Dolomite Handling Chain Conveyors

Description	CV-312A and B	CV-313A and B	CV-314A and B
Function	Transfer material from (1 day) Dolomite Storage Silo TK-309 to secondary Dolomite Crushers CR-304A and B via vibratory feeders	Dolomite screens rejects after secondary crusher	From secondary crusher screens to Dolomite Surge Bins BN 304A, B, and C
Quantity	2	1	2
Chain Speed, ft/min	50	5	50
Capacity, t/h	41	4.1	41
Drive, hp	10	1	5
Conveyor Rise/Length, ft	50/100	0/50	85/130
Nominal Size, in.	11	11	11

Table 2.5.1.4 Coal-Handling System Vibration Feeders

Description	V-303A and B	V-305A, B, C, and D	V-307A and B	V-308A and B	V-301A
Function	Activator/Feeder	Activator/Feeder	Bin Activation	Rate Control Feeder	Activator/Feeder
Location	Inlet to Coal Crushers CR-301A and B	Outlet of 3-Day Coal Storage Silo TK-306A	Outlet of 1-Day Storage Silo TK-308A	Outlet from Vibratory Feeder V-307A and B	Emergency Reclaim Tunnel
Quantity	2	4	2	2	1
Motor	5 hp, 720 rev/min, Tenv.	15 hp	10 hp	10 hp	10 hp, 720 rev/min, Tenv.
Capacity	800 t/h of 2 in. x 0 Coal	400 t/h of 1/2 in. x 0 Coal	142 t/h	35-142 t/h of 1/2 in. x 0 Coal	800 t/h of 2 in. x 0 in. Coal
Angle of Declination	0 deg	0 deg	0 deg	0 deg	---
Liner	1/2 in. Stainless Steel	---	---	---	1/2 in. 316 Stainless Steel on Pans and Arch Plate
Controls	Fixed Rate	Fixed Rate	Fixed Rate	Proportional	Automatic Proportional Control

- A storage area with active and inactive storage piles for the plant. The storage pile capacity and configuration meet the following conditions:
  - A 24,000-ton active reclaim storage pile capable of supplying dolomite to the plant for 24 days when it is operating at 100 percent capacity. This pile is formed by piling all 24,000 tons of dolomite on the east side of the yard conveyor. The active reclaim pile is adjacent to the inactive storage pile.
  - An emergency conveyor to continue unloading barges in the event the primary piling system is out of service. The conveyor can pile 10,000 tons atop the inactive storage pile before bulldozing is needed.
  - An emergency reclaim system, with an active reclaim capacity of 8000 tons without any bulldozing.
- A redundant reclaim system to ensure an uninterrupted and reliable dolomite supply to the bunkers. Dolomite is reclaimed at a normal rate of 800 t/h from either the primary reclaim system (stacker/reclaimer) or the emergency reclaim system. There is also a 100 percent redundant dolomite-handling system from the surge bin outlet to the lock hopper feed systems.
- Careful consideration for safety and equipment maintenance. The system design ensures adequate space and access for operating, maintaining, and removing each piece of equipment:
  - Monorails to serve each major piece of equipment with direct access to grade or to an equipment hatch; manual hoists for the short lifts and electric hoists for the long lifts
  - Access platforms, stairs, and ladders for all equipment Walkways and access aisles on both sides of all conveyors
  - Enclosed conveyor galleries that extend over the water and into/between the units.
  - Emergency escape ladders at intervals from conveyor galleries.

Major Equipment Description. The major components of the dolomite handling system are shown in Figure 2.5.1.1 and descriptions of the major components are given in Table 2.5.2.1. Portions of the system are used for both coal and dolomite handling and they are designated for dual use in Table 2.5.2.1.

Table 2.5.2.1 Dolomite Handling System

Description	*Tag No.*	*Quantity Required*	*Dimensions/Operating Data*
Barge Unloader	UL-301	1	Dual-use equipment (Table 2.5.1.1)
Belt Conveyors			(Table 2.5.1.3)
Chain Conveyors			(Table 2.5.1.4)
Magnetic Separator			
Location		1	Conveyor UL-304A discharge: dual-use equipment (Table 2.5.1.1)
Location		1	Conveyor CV-302 discharge
Drive			3 hp
Magnet			6171 W
Crushers			
Primary Dolomite Crushers	CR-302A, B	2	
Capacity			350 t/h each
Motor			175 hp; 720 rev/min; 4000 V
Secondary Dolomite Crushers	CR-304A, B	2	
Capacity			41 t/h each
Motor			35 hp; 1800 rev/min; 460 V
Sampling Systems			
"As-Received" Sampling-Type System			Three-Stage; automatic; proportional for 38-lb samples, with crusher, collector bin, and feeder belts
"As-Fired" Sampling-Type System			Two-Stage; incremental method with crusher and sample collector bin and feeder belts
Vibrating Feeders			Vibrating Feeders used in the dolomite-handling system are presented in Table 2.5.1.4
Flop-Gate Actuators		3	
Shut-Off Gate		2	
Location			200-ton Surge Bin BN-301A; Outlet to Crushers CR-301A and B
Manufacturer			Process Equipment Builders, Inc.
Sump Pumps			
Location			Crusher building/reclaim tunnel
Type			VN (vertical slurry pump)
Air Dryer			
Location			Crusher building. Transfer Building 1; Emergency reclaim
Manufacturer			Deltech Engineering, Inc.
Type			G Series, heatless dryers
Belt Cleaners			
Location			Head pulley, all conveyors
Belt Scales with Integrator			
Location			Conveyor UL-303, dual-use equipment (Table 2.5.1.2)
Conveyors			CV-305A and B
Accuracy			¼ of 1%
Capacity Range			
Conveyor UL-305A			See Table 2.5.1.2
Conveyors CV305A and B			100 to 700 t/h
Telescopic Chute	TC-301A		
Location			Discharge of Conveyor ST-303
Air Compressor			
Location (1)			Barge unloader, dual-use equipment; See Table 2.5.1.1
Location (2)			Transfer Building 1; dual-use equipment. See Table 2.5.1.1
Stacker/Reclaimer			Dual-use Equipment; See Table 2.5.1.1

2.5.3 Coal and Sorbent Feeding

With the coal containing both sulfur and alkali the plant utilizes two different sorbents, e.g., limestone to control/minimize stack gas sulfur releases and emathelite to control/minimize alkali vapors that could be corrosive to the gas turbine. The limestone is mixed with the coal being fed to the plant whereas the emathelite is sprayed into the gas streams proceeding to the gas turbine. As a result the plant utilizes two different types of feed systems as follows:

Coal and Limestone. The coal and sorbent, both crushed to 1/8” x 0 and dried to 5 percent surface moisture (drying is required by the feed system manufacturer to insure the material flows freely), are fed into the carbonizer and PCFB boiler as a blend via commercially available lock hopper feed systems. The carbonizer utilizes three 50 percent capacity lock hopper feed trains and the PCFB two 100 percent capacity trains. Each feed train consists of a vertical stacking of four vessels supplied with coal and sorbent from separate day bins located above each train. Gravimetric feeders provided under the day bins transfer the coal and sorbent in desired molar ratios (Ca/S = 1.75) to a mixer that blends the material and discharges to the first vessel in the feed train. The first vessel is a surge bin that runs at atmospheric pressure and discharges its coal-sorbent blend in batches by gravity to a lock hopper vessel. The transfer occurs at atmospheric pressure and when complete inflatable seal valves at the inlet and outlet of the lock hopper allow the vessel to be pressurized with air. Upon completion of pressurization the bottom valve is opened and the material drains into the third vessel called an injector. When the transfer is completed, the bottom seal valve is closed and the lock hopper depressured by venting to a baghouse (the fourth vessel) located above the surge bin; the baghouse removes gas entrained particulate and drains the collected material back to the surge vessel. When the lock hopper reaches atmospheric pressure, the vent valve closes, the top inflatable seal valve opens, the vessel is refilled, and the cycle repeated.

The injector vessel runs slightly above process pressure and a feeder at its bottom transfers the coal sorbent blend to a pneumatic transport line that conveys and injects the material into the carbonizer or PCFB boiler.

At full load all coal and sorbent enter the system via the carbonizer (the PCFB boiler only requires direct coal sorbent feed at part load and start-up). Assuming all three carbonizer feed trains are in operation, each injector vessel when filled contains about a 40 minute supply of material and the lock hoppers cycle at the rate of three times per hour. With all sorbent reaching the PCFB boiler by way of the carbonizer and char collecting hopper, the PCFB is provided with a separate small sorbent feed train for bed inventory control and trimming of SO_2 emissions; this train is also used to charge the PCFB boiler with a bed of sand at start up.

The coal, limestone, and sand feed trains required by the plant are shown in the Figure 2.5.3.1 Carbonizer Process Flow Diagram and in elevation view in Figure 2.5.3.2.

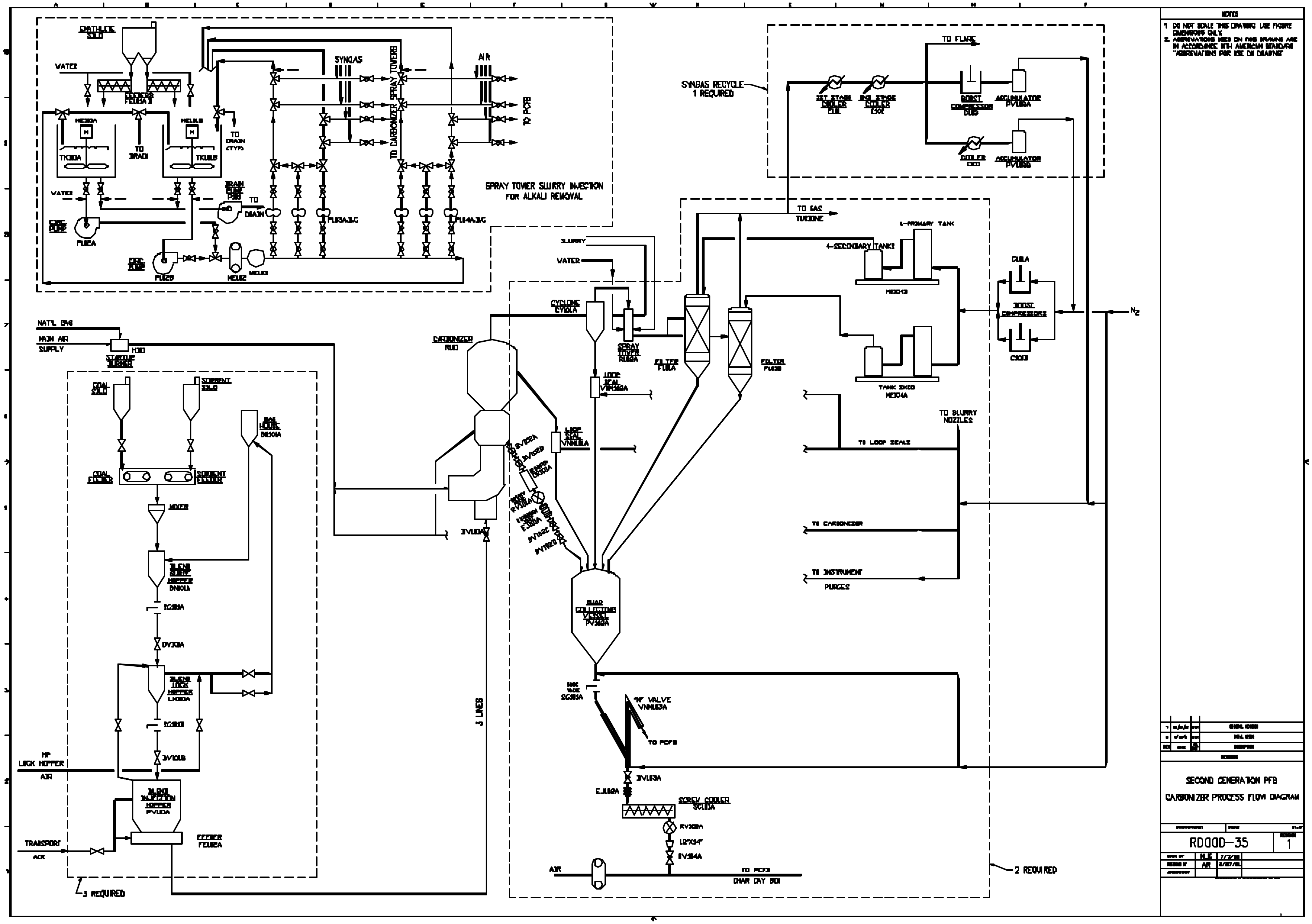
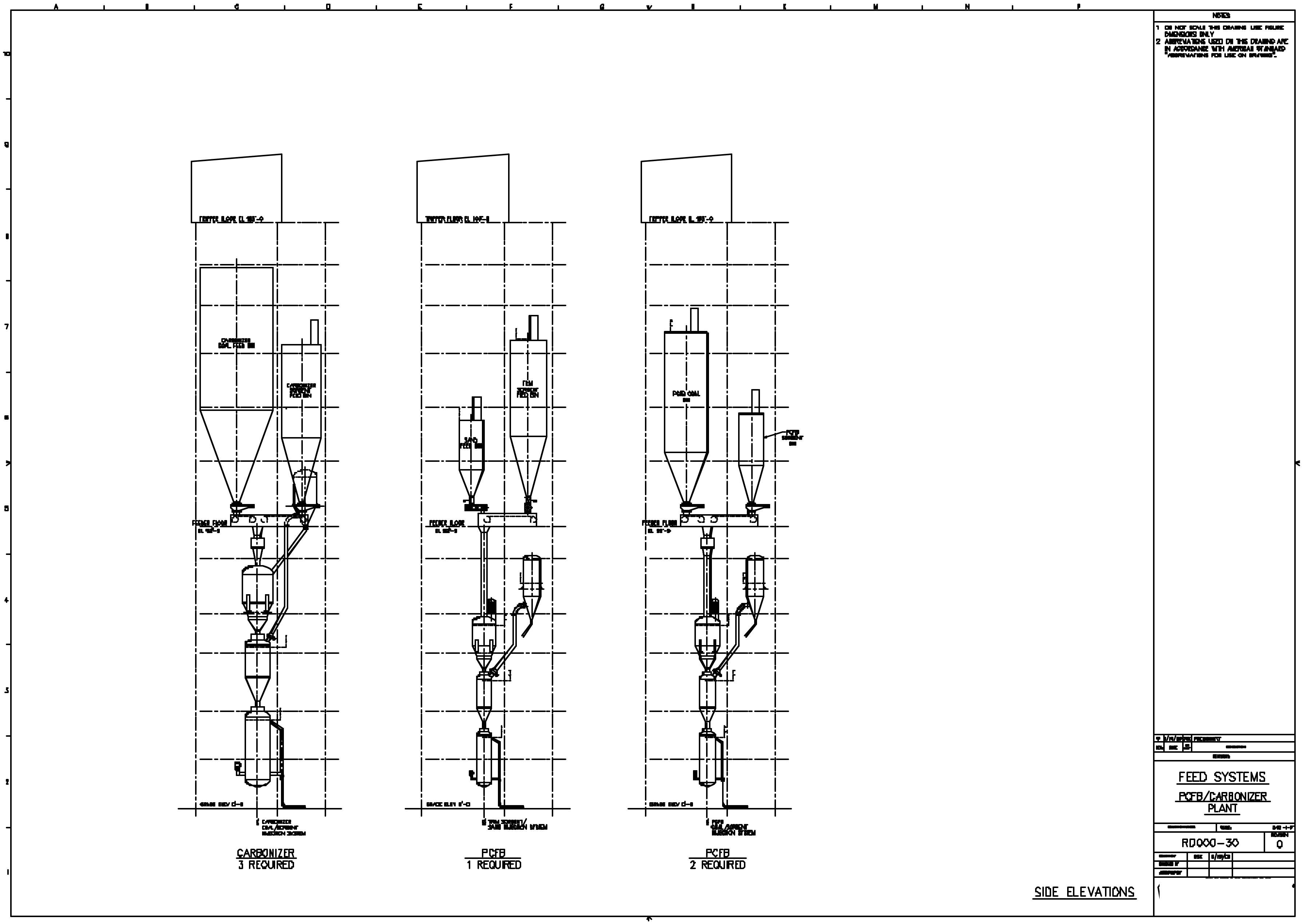


Figure 2.5.3.1 Carbonizer Process Flow Diagram



NOTES

1 DO NOT SCALE THIS DRAWING. USE FIGURE DIMENSIONS ONLY
2 ABBREVIATIONS USED ON THIS DRAWING ARE IN ACCORDANCE WITH AMERICAN STANDARD "ABBREVIATIONS FOR USE ON DRAWINGS".

Figure 2.5.3.2 Coal-Dolomite-Sand Feed Trains

Emathelite. Pulverized emathelite is mixed with water to form a 25% emathelite 75% water slurry by weight that is injected into the gas streams that ultimately proceed to the gas turbine topping combustor. The slurry is injected upstream of the ceramic candle filters and, to insure complete vaporization of the slurry water before reaching the filters, the spray towers are designed for 2 second gas residence times. The emathelite captures alkali vapors both during its gas transport to the filters and as it accumulates in the filter dust cake to limit alkali vapor levels to less than 20 pppbv. The slurry injection requirements are 4000 lb/hr and 800 lb/hr for the carbonizer syngas and the PCFB boiler flue gas streams respectively.

The emathelite slurry preparation and pumping system required by the plant is shown in the Figure 2.5.3.1 process flow diagram. The plant utilizes two 100 percent capacity slurry preparation trains. Pulverized emathelite is delivered to the site by pneumatic transport truck and loaded into a silo with two outlets. A loss in weight feeder at each outlet controls the emathelite withdrawal rate and transfers the material to an agitated tank where the emathelite and water are added and mixed. Each of the two tanks holds a 24-hour full load supply of slurry and is provided with two pumps, one for draining the tank at shut down and the other for supplying slurry to a common distribution/recirculation header. The quantity of slurry being pumped and its density are determined by a Coriolis type meter; the density measurement is used to confirm that a proper emathelite-water mix ratio is being maintained at all times. A total of six metering pumps extract a portion of the slurry from the header. Three pumps (one is a spare) supply slurry to the two carbonizer spray towers and the other three similarly supply the two PCFB spray towers. Each spray tower contains two nozzles one of which is a spare. To minimize droplet sizes and to speed evaporation under all load conditions, atomized/dual fluid nozzles are used with recycled syngas and air being employed on the carbonizer and PCFB gas streams respectively. Three-way valving and double block valving are provided throughout the piping system to allow uninterrupted operation should one component require on-line maintenance/replacement. Slurry not extracted for the spray towers is returned to the operating mix tank thereby maintaining pipe velocities that prevent separation of the slurry under all operating conditions.

2.5.4 Carbonizer Subsystem

The carbonizer subsystem produces a hot low Btu syngas suitable for combustion in the gas turbine topping combustor together with a char sorbent residue for combustion in the PCFB boiler. The major components of the subsystem are shown in the Figure 2.5.3.1 process flow diagram and consist of:

1. a single carbonizer vessel that produces the syngas and char residue
2. two bottom bed drain lines
3. two top of bed overflow drain lines
4. two primary stage cyclones each followed by two ceramic candle filters that strip the syngas of entrained particulate
5. two spray towers operating in parallel that spray water and an emathelite slurry into the syngas to limit the filter inlet temperature to 1600EF and capture alkali vapors corrosive to the gas turbine
6. two char collecting hoppers that operate at the filter inlet pressure and collect the char sorbent residue that drains from the above components

7. two N-shaped non-mechanical valves that control the transfer of the collected char sorbent residue to the PCFB boiler
8. a syngas recycle system that supplies cooled pressurized syngas for filter pulse cleaning, pressure tap purges, loop seal fluidization, etc.
9. two slurry processing/pumping systems that supply the spray towers with emathelite slurry

Figure 2.5.4.1 shows the major components in plan and elevation views.

Carbonizer. The carbonizer devolatilizes and partially gasifies coal in a jetting fluidized bed operating at approximately 285 psig with a substoichiometric supply of air. Coal and dolomite are fed to the unit at full load rates of 262,627 and 42,493 lb/hr respectively together with 600EF air and 450EF steam that result in a 1700EF operating temperature. A 1700EF coal derived syngas and char-sorbent residue are produced at approximate rates of 733,000 and 178,000 lb/hr respectively. Slightly over 50 percent of the coal carbon is consumed/released to the syngas; the syngas has a lower heating value of approximately 140 Btu/SCF and possesses the typical composition shown in Table 2.5.4.1. A portion of the coal sulfur is released to the syngas but the dolomite, which is supplied at a Ca/S = 1.75, captures the sulfur as calcium sulfide with an efficiency of 96.5% efficiency.

Table 2.5.4.1 Typical Carbonizer Syngas Composition

Component	Mole%
Carbon Monoxide	19.85
Carbon Dioxide	7.36
Hydrogen	16.90
Water	7.73
Methane	2.25
Ammonia	0.24
Hydrogen Sulfide	0.02
Nitrogen	45.10
Argon	0.55

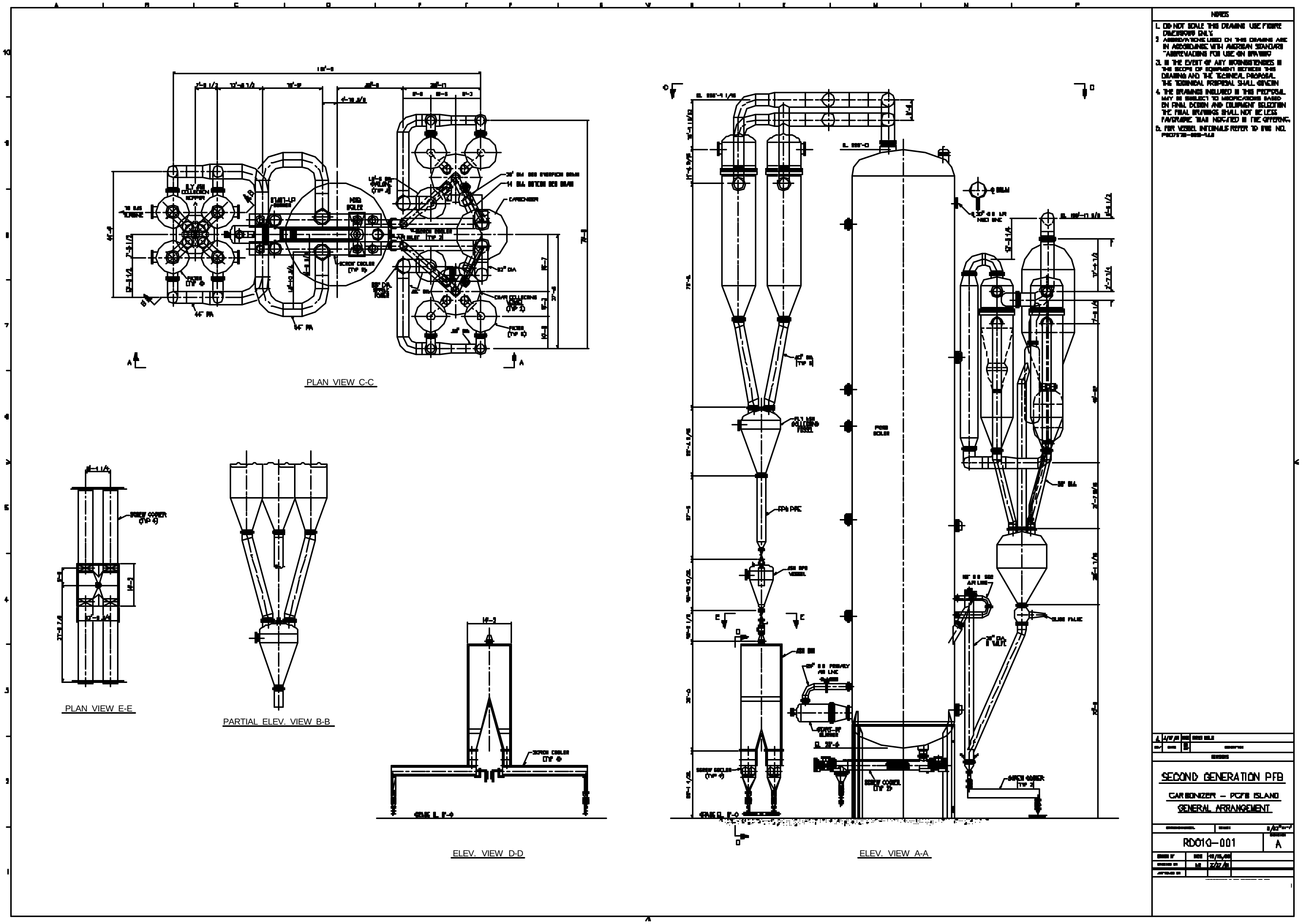


Figure 2.5.4.1 Carbonizer-PCFB Island General Arrangement

The syngas produced by the carbonizer ultimately fuels a gas turbine topping combustor and so the carbonizer is operated to meet the gas turbine need for syngas. As plant load is reduced, the gas turbine demand for syngas reduces and all flows to the carbonizer are reduced accordingly; for operating simplicity purposes the flows will be reduced in proportions that maintain the carbonizer at a nominal 1700EF over the plant operating envelope. Should a change in coal quality occur that significantly affects the carbonizer syngas yield per pound of coal fed, the carbonizer temperature can be adjusted accordingly, e.g., increasing the carbonizer air to coal feed ratio increases the carbonizer temperature, carbon conversion, and gas yield and the converse is true. For the Pittsburgh 8 coal specified for the plant, a 1600EF to 1800EF operating window is recommended for the carbonizer which should accommodate all reasonable changes in coal quality.

As shown in Figure 2.5.4.2, the carbonizer is a 16-ft. 8-in. diameter by 47-ft. tall pressure vessel. The inside surfaces of the vessel are protected from the high process temperatures by an 11-in. thick refractory lining consisting of five inches of an erosion resistant hard face lining backed by six inches of a thermal/insulating lining; after refractory lining, the vessel has a 14-ft. 6-in. inside diameter. The unit operates with a superficial gas velocity of 4 feet per second with a 25-ft. expanded bed height and a 20-ft. tall freeboard. At the 50 percent minimum load point flows and pressure reduce and result in a 3 feet per second velocity that maintains bed fluidization and mixing characteristics. Since bed material is continuously drained from the unit via over flow nozzles described below, bed and freeboard heights are maintained throughout the operating envelope.

Coal and sorbent are pneumatically injected into the unit via three vertical lines located at the bottom of and around the centerline of the unit. The three feed pipes are spaced 120 degrees apart and contained within the main 24-in. diameter air flow pipe. The air from these streams enters at a jet velocity of about 60 feet per second. Although the jet rapidly dissipates and remains submerged in the bed at all time, it does, together with the steep sides of the hopper bottom, induce rapid mixing of bed material. Feed and bed material flow up along the centerline of the unit and back down along the walls to the bottom where they are drawn back into the jet; this continuous recirculation of bed material controls the jet temperature and jet induced attrition prevents agglomerates from forming.

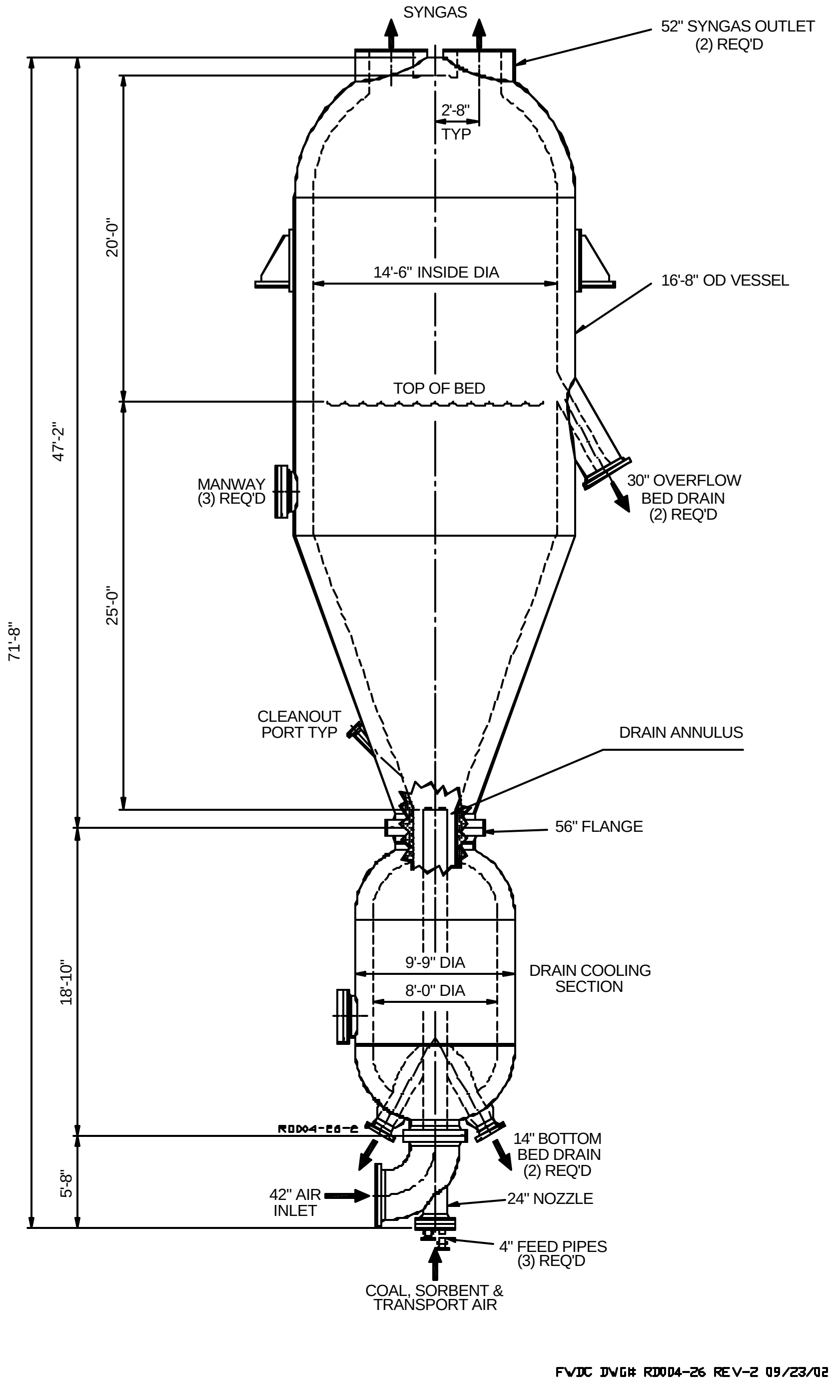


Figure 2.5.4.2 Carbonizer General Arrangement

The 1700EF syngas, containing elutriated char and sorbent, exits from the top of the unit via two vertical nozzles each 28 inches in inside diameter (ID). Two 11-in. ID overflow nozzles near the midpoint of the unit limit the bed height to 25-ft. and convey the material to the char collecting hopper. Since the char collecting hopper operates at a slightly lower pressure, each of the overflow lines contains a loop seal fluidized with recycle syngas at their point of discharge to the collecting hopper. A 4-in. wide annulus around the main air feed pipe allows material to drain into an 18-ft. tall cooling section. Here the draining material is cooled to 500EF as a packed bed by a counter flowing stream of cooled, recycled syngas that rises and fluidizes the drain annulus. Two 14-in. nozzles at the bottom of the cooling section are used to drain material at shut down and once a shift during normal operation for bed cleansing/removal of old bed material. Each bottom drain line conveys the material to the char collecting hopper and a rotary valve, protected by an upstream delumper, controls the drain rate. The two overflow and two bottom drain lines provide the unit with 100 percent redundancy for draining material; in addition the delumper and rotary valve are provided with double block and bleed valves to allow for on line maintenance of these rotating components.

Cyclone. The syngas exits the carbonizer via two 52-in. OD lines that are refractory lined to a 32½-in. ID. Each line contains a single cyclone that removes the coarser fraction of the gas entrained particulate before they ultimately enter the ceramic candle filter described in Section 2.5.7. The cyclone possesses a conventional tangential inlet-vertical axis configuration but with pressure vessel wall construction and abrasion resistant internal refractory lining. The cyclone is 10-ft. 4-in. in diameter by approximately 38-ft. tall. Solids collected by the cyclone drain to the char collecting hopper and a loop seal, located at the base of the cyclone dipleg and fluidized with recycle syngas, provides the necessary cyclone to filter inlet pressure seal. Syngas exits the cyclone via a 48-in. diameter pipe refractory lined to a 28½-in. inside diameter and proceeds to a spray tower.

Spray Tower. One spray tower is provided downstream of each of the two cyclones to permit the injection of two separate streams. The first is a 4,490 lb/hr water spray that together with the second 2,000 lb/hr slurry spray cools the syngas from 1700EF to 1600EF, the desired filter inlet temperature. The slurry contains pulverized emathelite in a 25 percent solids 75 percent water mass mix ratio and the emathelite adsorbs/removes alkali vapors that could cause corrosion of the gas turbine. The two injections occur via separate atomized/dual fluid spray nozzles as the syngas flows down through a 50-ft. tall 68-in. diameter section of piping refractory lined to a 48-in. inside diameter. The nozzles are located on the centerline near the top of the spray tower and each nozzle is provided with a spare. The slurry sprays concurrent with the 1700EF gas flow and atomization assures a minimum droplet size under all load conditions (droplet evaporation times are estimated to be less than 250 milliseconds). The large inside diameter of the spray tower reduces the gas velocity to 25 feet per second, provides for 2 seconds of gas residence time, and vaporizes the water droplets before they reach the ceramic candle filter described in Section 2.5.7.

Char Collecting Hopper. The carbonizer leg of the plant utilizes two hoppers operating in parallel with each collecting the char sorbent residue draining from one of the two syngas and bed drain equipment trains. Each hopper is a 14-ft. diameter by approximately 30-ft. tall pressure vessel that is refractory lined to a 12-ft. 2½-in. inside diameter. The hoppers operate at the filter inlet pressure and, assuming an equal distribution of char at full load, each can hold up to a half-hour supply of char sorbent residue. The amount/level of residue in each hopper is monitored by both continuous and point alarmed nuclear level indicators. The N valves described below are operated to maintain the residue level at 17 feet above discharge, plus or minus 5 feet. By keeping the level within this control band, the residue is transferred to the PCFB boiler at the rate it is generated. A small nitrogen flow is injected into the hopper drain line to strip residual syngas from the particle interstices and the collected char together with the N valve provide a gas seal between the reducing atmosphere of the carbonizer and oxidizing atmosphere of the PCFB boiler sections of the plant.

N Valve. The char sorbent residue collected by each collecting hopper is transferred to the PCFB boiler at controlled rates via a non-mechanical N valve; the valve consists of a vertical 36-in. line refractory lined to a 16¾-in. ID that is preceded by and followed by pipe sections sloped 60 degrees to the horizon. Char sorbent residue drains by gravity from the char collecting hopper through the downward sloping piping to the base of the vertical line. Steam is injected at controlled rates through a grid at the base of the line and is used to fluidize the vertical column of material. Increasing the fluidizing velocity causes the residue to flow through the N shaped piping at increasing rates; in addition to fluidizing the riser, the steam provides an assist in helping move/blow the residue down the inclined line into the PCFB and acts as a buffer between reducing and oxidizing legs of the plant. A ceramic-lined slide valve in the drain line from the char collecting hopper to the N valve is provided to insure that residue transfer is kept under control at all times and the steam flow is backed up with nitrogen.

2.5.5 PCFB Subsystem by FW

The PCFB boiler subsystem combusts the carbonizer char-sorbent residue and uses the heat release to produce 1600EF flue gas/vitiated air for the gas turbine topping combustor and 1050EF superheated and reheated steam for the steam turbine. The major components of the subsystem are shown in the Figure 2.5.5.1 PCFB Process Flow Diagram and consist of:

1. a single pressure vessel containing the PCFB boiler with its 2 recycle cyclones and 3 fluidized bed heat exchangers
2. two bottom ash bed drains that operate in parallel to control the inventory of sorbent and ash circulating in the PCFB boiler
3. a slurry spray station located in the flue gas piping from each recycle cyclone that injects emathelite to control vitiated air alkali levels
4. four ceramic candle filter vessels described in Section 2.5.7 that operate in parallel to strip the vitiated air of entrained particulate
5. one ash handling system that collects, depressures, and cools the PCFB boiler bottom and fly ash for transport to ash storage silos

Figure 2.5.4.1 shows the major components in plan and elevation views.

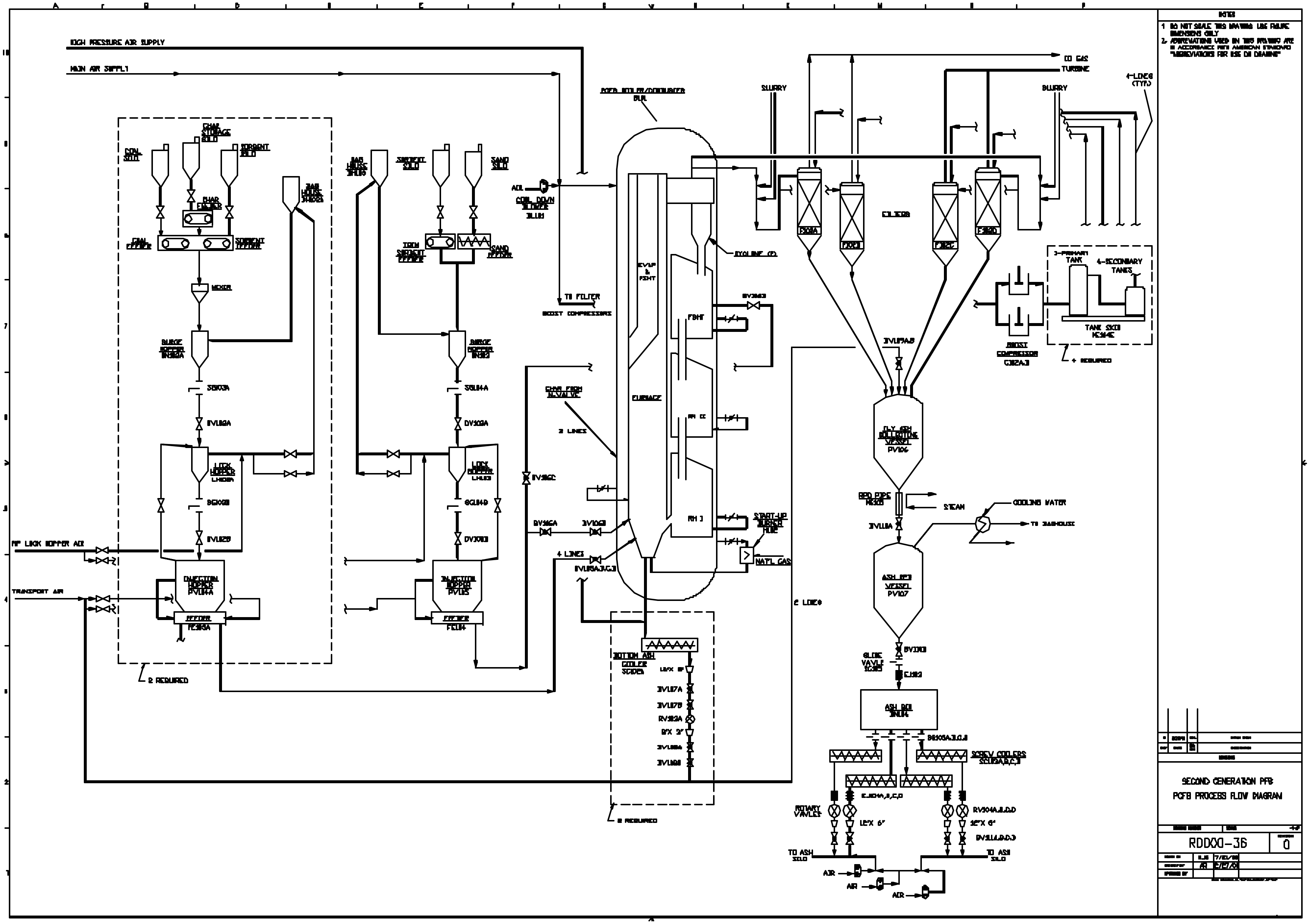


Figure 2.5.5.1 PCFB Process Flow Diagram

PCFB Boiler. The char-sorbent residue generated by the carbonizer is combusted at 1600EF in the PCFB boiler with 600EF 285 psig air supplied from the main air boost compressor. At full load the char heat release totals approximately 1,400 MMBtu/hr and the PCFB boiler uses this heat to supply 1600EF flue gas/vitiated air to the gas turbine topping combustor and 1050EF superheated and reheated steam to the 2400 psig 260 MWe steam turbine. As plant load is reduced the gas turbine and steam turbine power reduce in different proportions. (At 50 percent load the gas turbine and steam turbine power levels are at 44 and 67 percent of full load values respectively.) With syngas and char generation rates decreasing at a faster rate than the reduction in steam turbine power output, two feed trains operating in parallel are provided to supply a coal-dolomite blend directly to the PCFB boiler to maintain superheat and reheat temperatures over the entire load range. As a result the PCFB boiler is operated/fired to meet steam turbine demands. At minimum load the PCFB boiler operates at 1550EF, the coal feed requirement is a maximum, and each of the two feed trains have the capability to supply 100 percent of this flow.

The PCFB boiler excess air level ranges from 50 percent at full load to 30 percent at 50 percent load. Even though pilot plant tests have yielded combustion efficiencies in excess of 99.9 percent at these conditions, a conservative value of 99 percent combustion efficiency has been assumed for the PCFB boiler.

The sulfur contained in the coal and char are released in the PCFB boiler as sulfur dioxide. Although dolomite is fed to the plant at a Ca/S molar ratio of 1.75, based on the sulfur remaining in the char and the remaining unused sorbent, the PCFB boiler operates with a Ca/S ratio of 4.4 and captures the sulfur as calcium sulfate at an efficiency of 99 percent. The used sorbent that accompanies the carbonizer char contains calcium sulfide and, under the PCFB oxidizing conditions together with the scouring associated with the continuous circulation of solids through the unit, the calcium sulfide is converted to calcium sulfate.

Figures 2.5.5.2 through 5 are simplified sketches of the PCFB boiler whereas dimensional and mechanical details together with sectional views referenced further on are presented in Figure 2.5.5.6. The PCFB boiler consists of a furnace or riser section, two cyclones complete with dip legs and loop seals, and three vertically stacked Integrated Recycle Heat Exchangers (IntrexJ) with bypass and return channels for circulating fluidized bed material. The PCFB boiler is in essence a conventional circulating fluidized bed (CFB) boiler that has been placed inside of a pressure vessel to allow operation with 294 psig air. To minimize the pressure vessel diameter the Intrex units are stacked vertically above each other rather than set side by side at one elevation as would be done with an atmospheric pressure CFB. Char, coal, and lime based sorbent are injected at the bottom of the riser to form a fluidized bed primarily consisting of sorbent and fly ash.

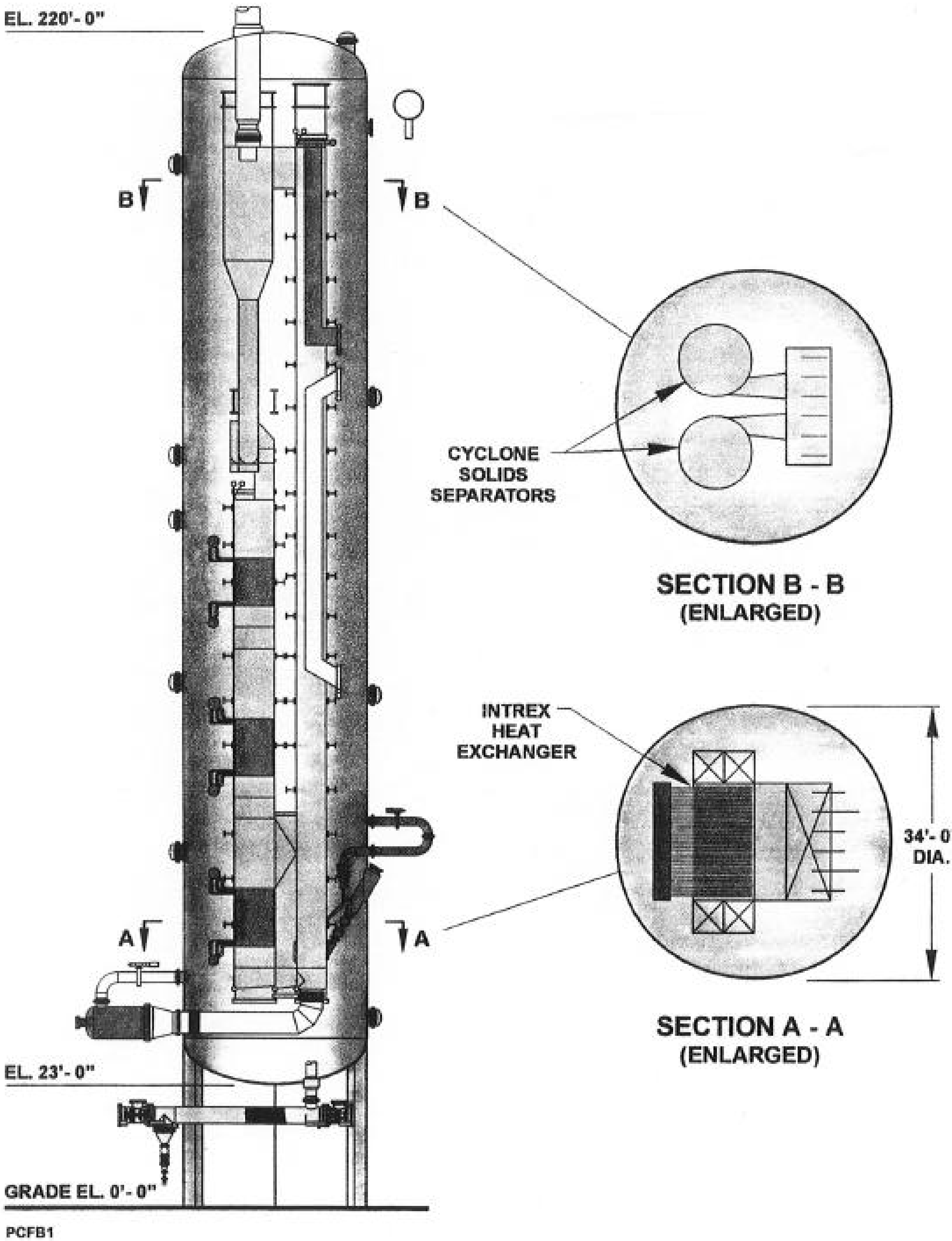


Figure 2.5.5.2 Pressurized Circulating Fluidized Bed Boiler Simplified General Arrangement

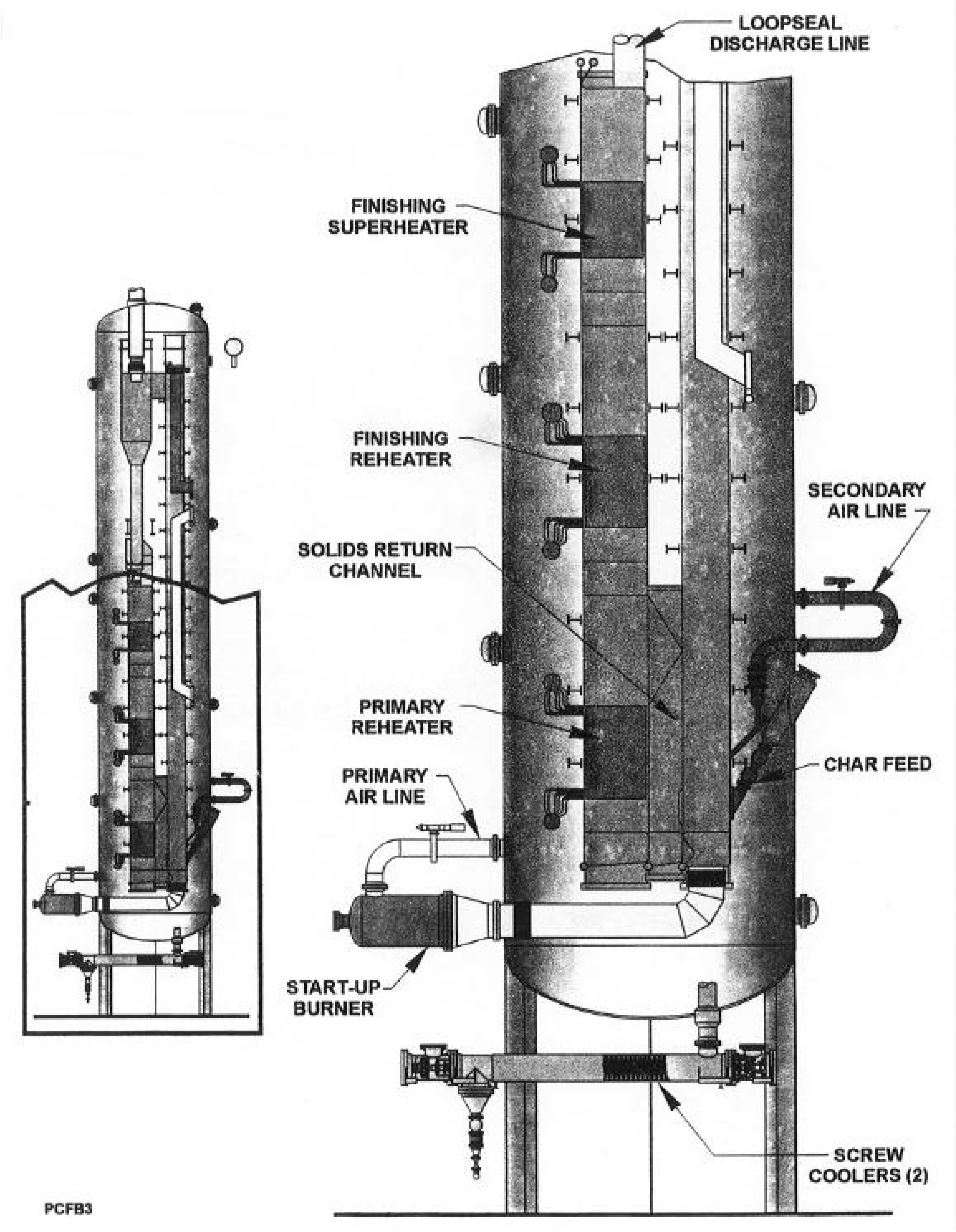


Figure 2.5.5.3 PCFB Boiler Simplified Lower Section

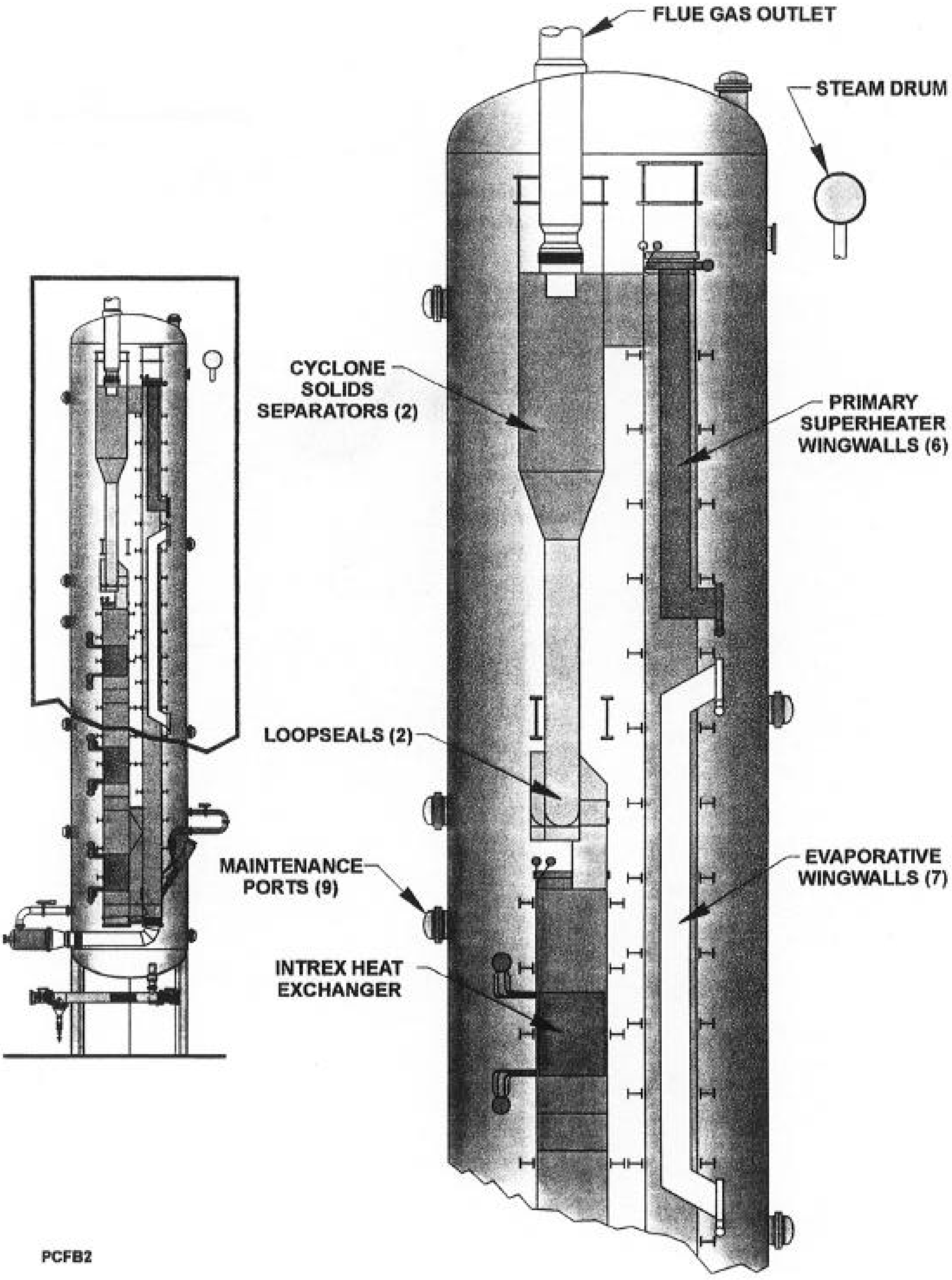


Figure 2.5.5.4 PCFB Boiler Simplified Upper Section

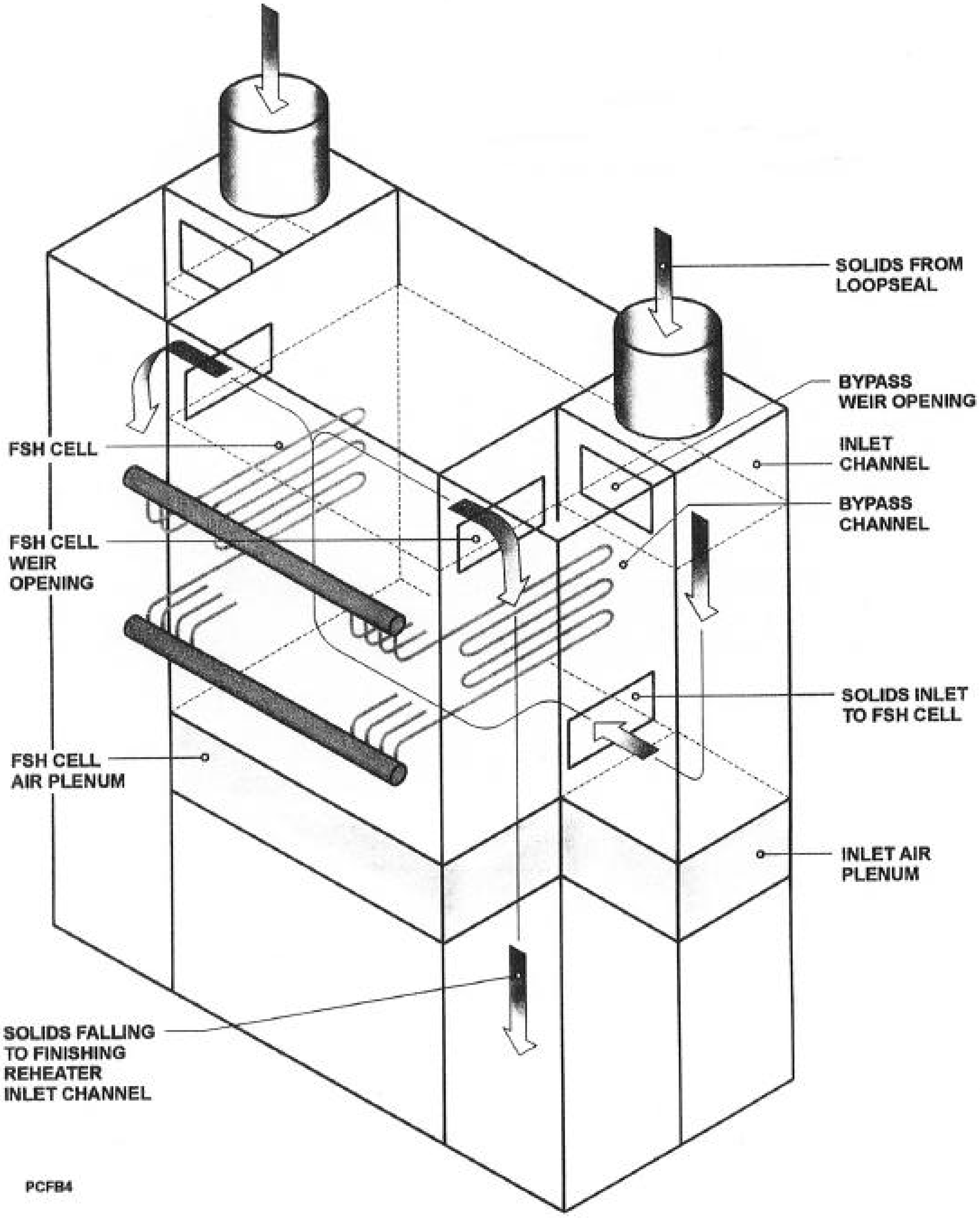


Figure 2.5.5.5. Intrex Heat Exchanger Solids Flow Path – Normal Operation

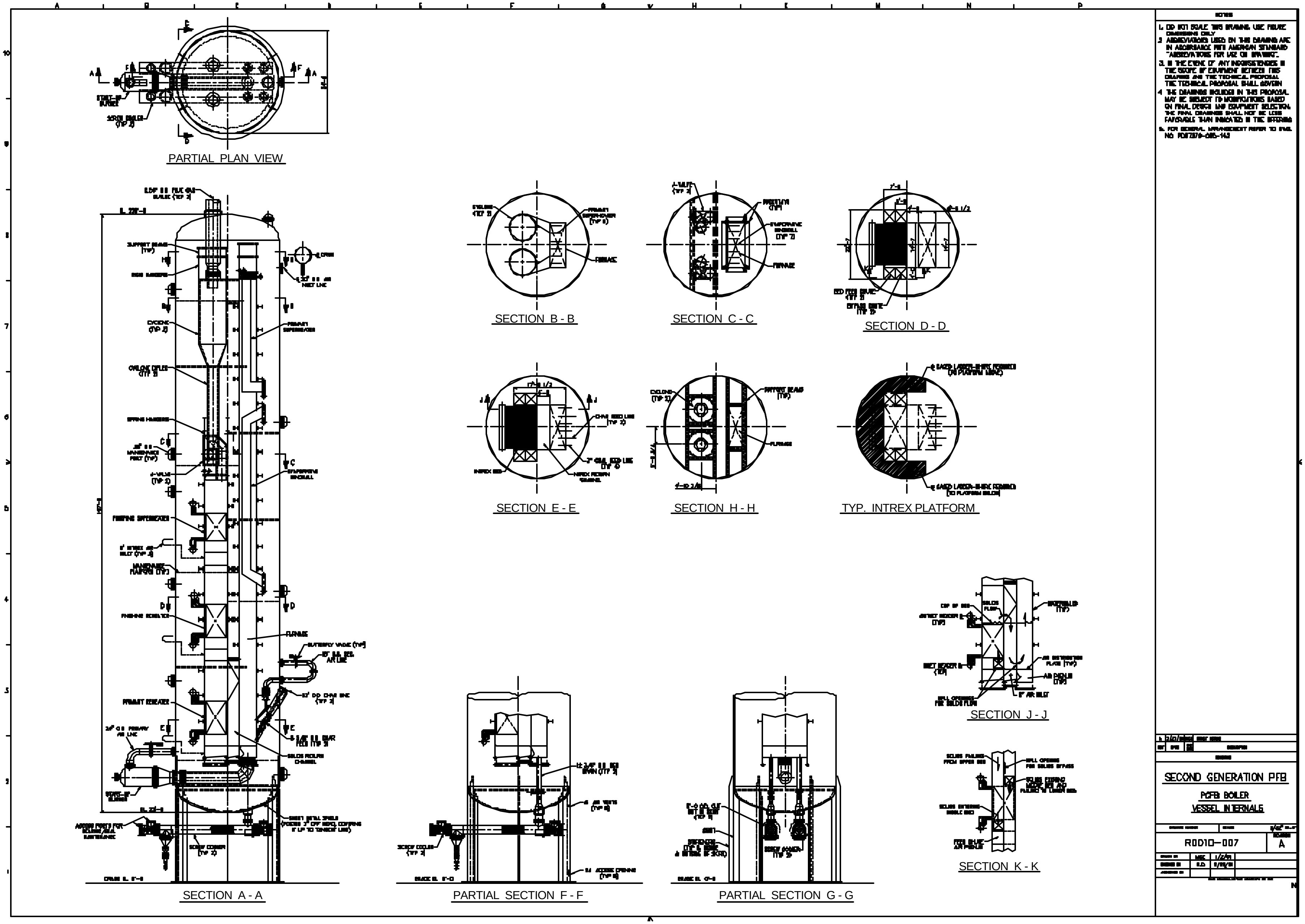


Figure 2.5.5.6 PCFB Boiler General Arrangement

Air is injected into the bed in stages to control NOx formation, char and coal are combusted, sulfur is released from the fuels as sulfur dioxide, and the lime based sorbent reacts with the latter to capture sulfur as calcium sulfate. Combustion heats the bed to 1600EF and a resulting nominal 16 ft/sec superficial flue gas velocity entrains bed material. At minimum load the bed temperature and velocity decrease to 1550EF and 15 feet per second respectively but both high enough to maintain the PCFB's high performance characteristics. The flue gas with entrained particulate flows vertically up to the top of the riser, exits horizontally through two refractory lined outlet ducts, passes through two cyclones operating in parallel that remove the bulk of the entrained solids, and exits from the top of the cyclones and vessel. Solids captured by the cyclones drain through dip legs and loop seals, and cascade through the three vertically stacked Intrex units that cool the solids to approximately 1275EF for return to the bottom of the riser.

Detail Description. In plan view the riser section is 5 ft.-6½ in. by 14 ft.-7 in. and the Intrex units are 7 ft.-6 in. by 14 ft.-7 in. The riser is about 161 ft.-6 in. tall, the two lowest Intrex units are about 31 ft.-10 in. tall, the upper Intrex unit is 27 ft.-10 in. tall, and the given riser and Intrex heights all contain 4 ft. tall air plenums. The walls, floors, and roofs of the riser, Intrex units, and solids bypass and return channels are all formed using waterwall tube construction stiffened by wrap around type buckstay steel beams as shown in Section C-C.

The riser contains two elevations of 3 ft. wide wing walls. The lower elevation contains 7 panels each about 46 ft. tall whereas the upper contains 6 panels each about 33 ft. tall. The lower wing walls together with all the waterwalls serve as evaporative surfaces; the upper wing walls serve as the primary superheater. Each of the Intrex units contains serpentine shaped tube bundles. The topmost or Intrex Number 3 tubebundle is 8 ft.-11½ in. tall and serves as the finishing superheater; the next lower Intrexes, Numbers 2 and 1 respectively, serve as finishing and primary reheaters with each containing 10 ft.-9½ in. tall tube bundles. The wing walls and tubebundles receive and discharge their cooling mediums (e.g., water or steam) to headers provided outside their enclosing waterwalls.

The steam drum is located outside the pressure vessel and two downcomer pipes lead feedwater to three 50 percent capacity boiler circulation pumps located at grade. From the pumps the feedwater piping penetrates the pressure vessel and distributes itself among the waterwall and wing wall supply headers. After passing through these heat transfer surfaces the resulting two phase water-steam mixture discharges to collection headers and is transported to the drum by riser pipes. Steam enters the PCFB boiler for superheating or reheating and, after passing through primary heating surfaces, exits the vessel, passes through temperature control spray stations, reenters the vessel for final heating, and exits for transport to the steam turbine.

Two refractory lined cyclones each 9 ft. in outside diameter are provided at the top of the riser. The cyclones strip entrained particulate matter from the riser flue gas, the gas discharges through two 54 in. OD refractory lined pipes that penetrate the top head of the pressure vessel and proceeds to downstream ceramic candle filters. The hot solids collected by the cyclones drain via refractory lined dip legs and loop seals to feed chutes connected to the uppermost Intrex unit.

Two chutes each approximately 4 ft. square in plan view are provided on both sides of each Intrex unit as shown in Section D-D. One chute on each side, the feed chute, contains an air plenum whereas the adjoining chute, the bypass chute, does not (see Figure 2.5.5.5). Each feed chute contains two wall openings. The lower wall opening discharges to the Intrex bed whereas the upper opening discharges to the bypass chute (see Section K-K). If the Intrex bed is not fluidized, solids cannot flow through the lower opening. As a result solids will collect in the feed chute and reach a level that eventually spills over/through the top wall opening into the bypass chute. When the Intrex unit is fluidized, solids will flow through the lower wall opening into the Intrex and the bed level will build up and eventually submerge the tube bundle. A wall opening provided in the Intrex unit controls the bed height by allowing bed material to spill over into the bypass chute. The bed discharge opening is located at the top of the tube bundle but below the elevation of the bypass opening in the feed chute (see Section K-K). Solids thus enter the bypass chute from either the feed chute or the bed discharge wall openings. The bypass chute in turn discharges to the feed chute of the next lower Intrex unit where a similar arrangement is provided. By a proper adjustment of fluidizing velocities in the Intrex units and feed chutes, solids can be bypassed around the bed tube bundles to prevent overcooling of solids or over heating of tube bundles at startup.

During normal operation none of the Intrex beds are bypassed; hot solids collected by the cyclones cascade through the 3 Intrex units and are cooled by the waterwall and steam cooled tubebundles. Solids discharge from the bottom most Intrex through an above bed wall opening into the Intrex solids return channel (see Section J-J). The solids together with all the fluidizing air used in the Intrex units and feed chutes enter the riser via a wall opening provided at the bottom of the return channel.

Solids Feed and Draining. The PCFB boiler is fueled by carbonizer char-sorbent residue entering through two 8 in. pipes and by a coal-sorbent blend entering through four 3 in. pipes near the bottom of the riser (see Section E-E). Two additional 4 in. lines supply sand to the riser and the top Intrex for startup and can also inject sorbent directly to the unit if immediate sulfur capture or bed inventory adjustment is needed. The solids that return from the Intrex beds are reheated to 1600EF in the riser and continuously circulate through the unit transferring their heat to the various parts of the PCFB boiler. During their continuous circulation attrition reduces the sizes of the solid particles, and, depending upon feedstock characteristics and operating conditions, about 75 percent of the residue eventually escapes the cyclones. To control the inventory of solids circulating through the riser and Intrex beds, solids are drained from the bottom of the riser via either of two 100 percent capacity lines that lead to pressurized water cooled screws located below the PCFB pressure vessel.

Air Flow Path. The 600EF 285 psig air enters at the top of the pressure vessel via a 30 in. line and flows vertically down through the annular shaped space defined by the vessel inside diameter and the PCFB boiler. As the air flows inside the vessel it is distributed among the air plenums provided at the bottom of the riser, feed chutes, Intrex units, and return channel as well as riser secondary air injection nozzles. Valves, located outside of the pressure vessel to facilitate maintenance, control the air flow to each of these locations. As a result the air leaves the vessel, passes through a control device/butterfly valve, and reenters the vessel by piping that feeds each of these users (see Section A-A). In addition to a control device, the air piping to the riser plenum contains a natural gas fired burner that is used to heat the unit to ignition temperature at startup.

Pressure Vessel. The PCFB boiler is contained within a 3 in. thick pressure vessel 34 ft. in outside diameter (OD) by 197 ft. tall. The vessel is designed and fabricated per the ASME Boiler and Pressure Vessel Code Section VIII Division II in SA 537 Cl 2 material. The vessel is oriented vertically, bottom supported by a skirt, and a surrounding platform steel structure provides lateral support for resisting wind and seismic loads.

The vessel is designed for a maximum working temperature of 700EF, the combustion air enters at 600EF, and the waterwall operates at the drum saturation temperature of about 680EF. Although not shown in the sketches and arrangement drawing, the enclosing pressure vessel has 3 in. of insulation and lagging applied to its 34 ft. OD for heat conservation. By having the air sweep the vessel to boiler annular space before entering the various air plenums, the vessel wall is kept at about 600EF and protected from any flue gas leaks, e.g., any enclosure wall leakage would involve 600EF air flowing in through rather than 1600EF flue gas flowing out through the walls. In addition, should any hot solids escape the enclosure walls and fall to the bottom of the vessel, the bottom head is protected by a stand off metal liner.

The PCFB boiler is top supported inside the pressure vessel and guided to grow downward; the riser and cyclones are supported from a truss at the top of the unit that carry their loads to the sides of the pressure vessel. The Intrex assembly is similarly supported but from a lower elevation inside the vessel. Since the riser and Intrex assemblies are connected at the bottom, the Intrex support incorporates spring hangers that absorb differential expansions caused by the two different support elevations. In addition expansion joints and or flexibility loops are provided in the various piping and tubing runs located within the unit.

Numerous 36 in. diameter accessways are provided in the vessel that lead to internal maintenance platforms. Each Intrex unit has been provided with sufficient freeboard height to allows individual tube elements to be withdrawn from/lifted up out of the tubebundle should repairs become necessary during the life of the unit. Accessways located at freeboard elevations enable replacement tubebundle sections to be brought directly into the freeboard regions for assembly and installation.

Field Erection. When empty the PCFB boiler and its 34 ft. OD by 197 ft. long pressure vessel weigh over 3,000 tons. Because of the large size and weight, shop assembly and barge shipment of a fully assembled unit is impractical. As a result the PCFB boiler will be shipped to the site in sections for field assembly. The enclosing pressure vessel will be field fabricated, pressure tested, Code stamped, and placed in position. An 18 ft. diameter disk will be cut out of the bottom head and a rectangular opening cut in the support skirt. PCFB boiler sections will be passed through the rectangular skirt opening, lifted through the disk opening, and installed inside the vessel. Upon completion of the assembly the skirt section and disk will be welded back into position by the vessel manufacturer; the vessel disk weld will be subjected to 100% x-ray and, since the operation will be treated as a repair by the original manufacturer, another pressure test will not be required.

Bottom Ash Removal. A mixture of used sorbent and ash, referred to as bottom ash, is drained continuously from the bottom of the PCFB boiler to control the inventory of circulating solids. Two 100 percent capacity drain lines are provided. A pressurized screw cooler cools the 1600EF bottom ash to 500EF and a pressurized rotary valve feeds the ash into a pneumatic transport line. Each transport line conveys the drained material to a common ash collecting hopper for depressurization and cooling as described further below. The two drain lines contain double block and bleed valving on both sides of the rotary valve to allow for on line maintenance.

Emathelite Spray Stations. Pulverized emathelite is injected into the flue gas exiting the PCFB boiler recycle cyclones to adsorb/remove alkali vapors that could cause corrosion of the gas turbine. The alkali sorbent is sprayed into each of the two 1600EF exhaust streams as a 25 percent emathelite 75 percent by weight water slurry at an injection rate of 400 lb/hr. Because the water injection rate is small (approximately 5 percent of that of the carbonizer) and since the piping run to the filter is long, no spray tower is required. Instead the slurry is sprayed into the 34½ in. ID refractory lined piping leading to the filter. Two 100 percent capacity (one is a spare) air atomized/dual fluid spray nozzles are located on the centerline of this piping. The slurry sprays concurrent with the 1600EF gas flow and atomization assures a minimum droplet size and rapid vaporization under all load conditions.

Ash Handling. The ash handling system depressures, cools, and transports the PCFB boiler ash to storage silos using a vertical equipment stacking consisting of 5 major components. The 1580EF fly ash collected by the four ceramic candle filters drains by gravity to the topmost component, a 13 ft. diameter, refractory lined, ash collecting pressure vessel. The two bottom ash pneumatic transport lines also discharge their cooled ash vertically downward through the head of this vessel. The transport air reverses direction and flows up the filter drain pipes at a velocity of about ¼ ft/sec. The combined fine and coarse ash streams collect in the vessel, their level is monitored via a nuclear level indicator, and they drain by gravity through a bottom nozzle with a mix temperature of less than 1300EF. As a moving packed bed, the ash passes through a 16 in. steam jacketed pipe contained within a 17.5 ft. tall 30 in. pipe and enters the Restricted Pipe Discharge (RPD) vessel. The entry nozzle extends down into and fills the vessel with ash. The slowly moving packed bed of ash drains through a bottom nozzle, passes through a slide valve, and free falls into an ash surge bin operating at atmospheric pressure. Four 33 percent capacity water cooled screws operating in parallel and preceded by maintenance slide gates cool the ash to less than 500EF; the cooled ash discharges to rotary valves that feed the material to two 100 percent capacity pneumatic transport lines that lead to ash storage silos.

The ash drained from the process is controlled by the slide valve positioned under the RPD vessel. The nuclear level indicator in the topmost/ash receiving vessel sets the slide valve position to maintain a constant ash level in that vessel and a continuous column of solids extends from the collecting vessel down into the RPD vessel. The latter runs at atmospheric pressure and a small amount of vitiated air flowing down through this moving packed bed of ash dissipates the process pressure and is vented to the gas turbine discharge. To allow for potential process upsets the RPD vessel is designed for full process pressure and provided with isolation valves that would allow batch type lock hopper operation if necessary.

2.5.6 Combustion Turbine and Accessories

The gas turbine is a Siemens Westinghouse W501G that has been modified to export air to and import hot syngas and flue gas/vitiated air from the carbonizer and PCFB boiler respectively.

Before these hot gases reach the gas turbine, pulverized emathelite is injected into each stream to remove alkali vapors and ceramic candle filters are used to remove all particulate. Hence, the gas turbine is protected from corrosion, erosion, and deposition and standard materials of construction are used that yield blade life commensurate with oil or gas fired units. The nominal performance parameters of this turbine are listed in Table 2.5.6.1.

Table 2.5.6.1 Gas Turbine Nominal Performance

Net power output	239.5 MWe
Carbonizer syngas import flow	202 lb/s at 1584 ^oF
Vitiated air import flow	495 lb/s at 1580 ^oF
Export air flow	632 lb/s at 811 ^oF
Gas turbine exhaust flow	1,221 lb/s at 1130 ^oF
Pressure ratio	19.2:1

This section describes the main elements of the gas turbine, the general equipment arrangement, the manifold systems for compressed air, syngas, and vitiated air, and the bypass system that protects the turbine in case of plant upset.

Gas Turbine. The modified W501G gas turbine consists of three basic elements: axial-flow compressor, topping combustion system, and turbine expander. These three elements are combined into a single assembly with a horizontally split and sectionalized casings, two-bearing rotor support, turbine air cooling system, compensating alignment system and axial-flow exhaust.

The axial-flow compressor design is derived from the W501F compressor. The compressor has 17 stages with advanced profile airfoils and a 19.2:1 pressure ratio. A single variable inlet guide vane assembly is used, together with opening the compressor bleed valves, to avoid compressor surge during startup. The guide vanes are also modulated to improve combined-cycle part load efficiency.

Although some compressed air is reserved for cooling various gas turbine components, about 55 percent is exported for process use (carbonizer, PCFB, feed pressurization and transport, PCFB bottom ash transport, and PCFB filter pulse cleaning).

For this application, the W501G incorporates 16 dual-fuel topping combustors, each of which is an MASB. The air is extracted through the 16 topping combustor assemblies arranged circumferentially around the turbine to ensure uniform air flows within the turbine. Coal-derived syngas from the carbonizer provides the fuel for the topping combustor, and the exhaust gas from the PCFB boiler, from which some of the oxygen has been depleted, is the vitiated air that provides the oxygen.

Bench-scale tests conducted at the University of Tennessee Space Institute [ES-1] demonstrated that the amount of NOx produced by the MASB operating in simulated 2nd Gen PFB conditions was equivalent to a syngas NH_3-to-NOx conversion rate of 8 to 10 percent. These tests also showed that about 10 percent of NOx contained in the vitiated was destroyed in the MASB, and the low heating value of the syngas essentially produced no thermal NOx. The NOx emissions leaving the MASB thus include 90 percent pass-through NOx produced by the PCFB boiler together with 10 percent of the syngas ammonia converted to NOx and no thermal NOx.

Syngas, vitiated air, and compressed air flow to and from each combustor as shown in Figure 2.5.6.1. Compressed air leaves the compressor and enters the housing around each combustor. Some of the air is mixed with vitiated air, and the rest is extracted through a perpendicular nozzle. Vitiated air enters each combustor, where it combines with compressed air to form the oxidizing mixture for the MASB. Except for mixing air, the compressed air is separated from the vitiated air by a containment sleeve. Syngas (or natural gas during startup) is injected into each MASB nozzle and burned, and the products of combustion are delivered to the gas turbine expander through individual transition ducts.

The W501G transitions are steam-cooled to allow the combustion turbine to operate at higher rotor inlet temperatures while maintaining the same burner outlet temperature as W501F-class combustion turbines. Steam that is generated in the PCFB boiler is manifolded into the thin exterior walls of the transitions to cool them. The W501G turbine in this application uses about 100,000 lb/h of 500-psia cooling steam, entering around 500^{o}F and leaving around 1050^{o}F. The hot steam leaving the transition is then returned to the hot reheat steam system to improve the overall efficiency of the combined cycle power plant.

The W501G turbine follows previous W501 designs, with curvic-clutched discs to transmit torque and a 4-stage turbine to optimize efficiency. The first three stages are air-cooled. The turbine uses advanced materials such as directionally solidified castings for the first two turbine rows and state-of-the-art electron-beam vapor-deposited thermal barrier coatings.

Rotor cooling air is provided by compressor discharge air extracted from the combustor shell. This provides a blanket of protection from hot blade path gases and eliminates excessive contaminants that could block critical cooling passages to the rotor blades. Other compressor discharge air is used to cool the turbine blade ring cavities and vane segments.

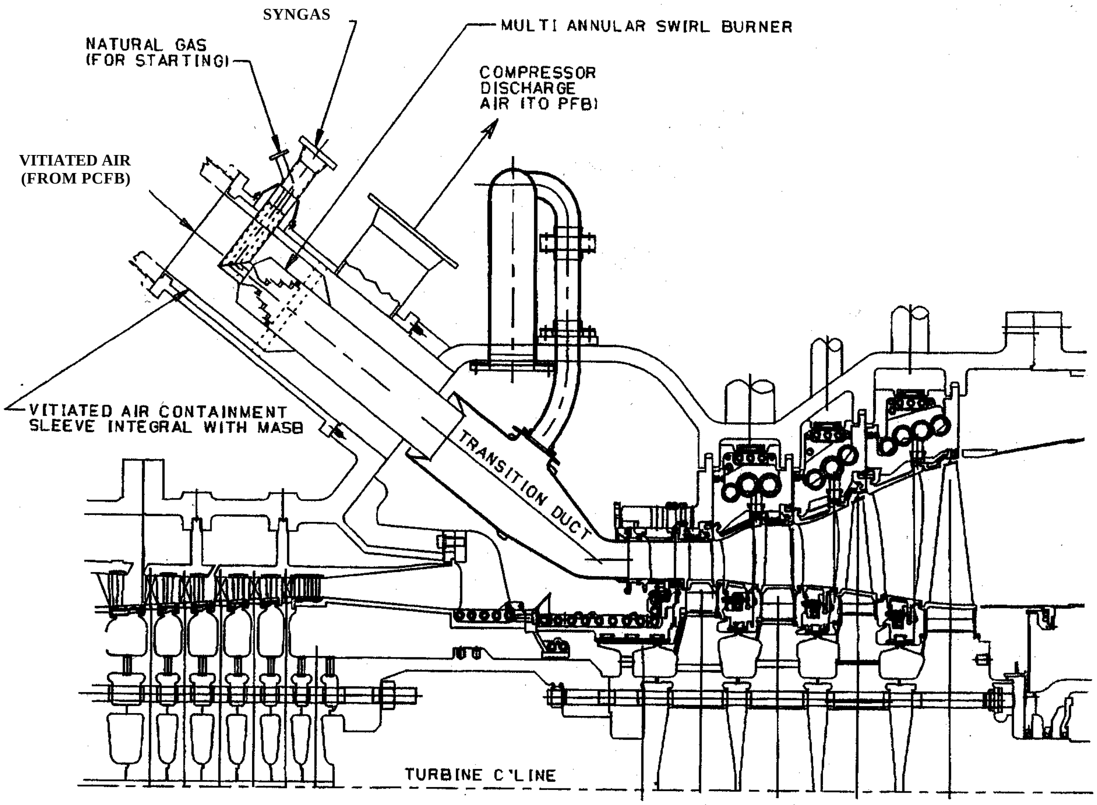


Figure 2.5.6.1 Syngas Combustor Flow Arrangement

General Arrangement. The bill of material for the basic gas turbine system includes the gas turbine assembly previously described, together with the following equipment and assemblies:

- Generator
- Static Excitations and Voltage Regulator System
- Starting Package
- Electrical Package
- Lube Oil System
- Gas Fuel System
- Inlet Air system
- Exhaust Gas System
- Compressor Water Wash
- Pipe Packages
- Cooling Assemblies
- Fire Protection System
- Auxiliary Transformer (Optional)
- Isolated Phase Bus (Optional)

The hydrogen inner cooled generator is equipped with integral lube oil and cooler piping, and necessary instrumentation. The design uses a shaft-mounted axial blower to circulate cooling hydrogen through the generator. A solid coupling connects the generator directly to the compressor at the cold end of the combustion turbine.

The major items of equipment in the gas turbine plant are listed in Table 2.5.6.2, along with their approximate shipping weights.

Table 2.5.6.2 Gas Turbine Plant Equipment Weights

Item	Weight, lbs
Gas Turbine	600,000
Syngas Manifold	75,000
Compressed Air Manifold	11,000
Vitiated Air Manifold	81,000
Generator	545,000
Collector	11,000
Starting Package	85,000
Electrical Package	3,000
Lube Oil Reservoir	16,000
Lube Oil Pump Skid	18,000
Turbine Piping Package	35,000
Excitation Skid	18,200
Excitation Transformer	16,700
Generator Seal Oil Skid	22,000
Fuel Oil/Water Inject. Skid	20,000
Fuel Oil Pump Skid	18,000
Water Injection Pump Skid	15,000

The heaviest piece lifted during construction is the generator, with a weight of 545,000 lbs. The heaviest piece lifted after construction is the bladed gas turbine rotor, with a weight of 118,000 lbs.

Figure 2.5.6.2 is a plan view that shows the arrangement of the gas turbine portion of the plant. The three large ring manifolds for vitiated air, syngas, and compressed air are shown located near the center of the combustion turbine. The enclosures, piping, wiring, fuel system, and the bypass system are not included because they would obscure the view of the major equipment items. The gas turbine unit occupies a space approximately 154 feet by 108 feet. The orientation of the turbine air inlet filter, shown at grade level in the figure, affects both the width and height of the configuration. If a narrower plant footprint is needed, the turbine air inlet filter can also be installed in an overhead orientation, in which inlet air enters the compressor from above.

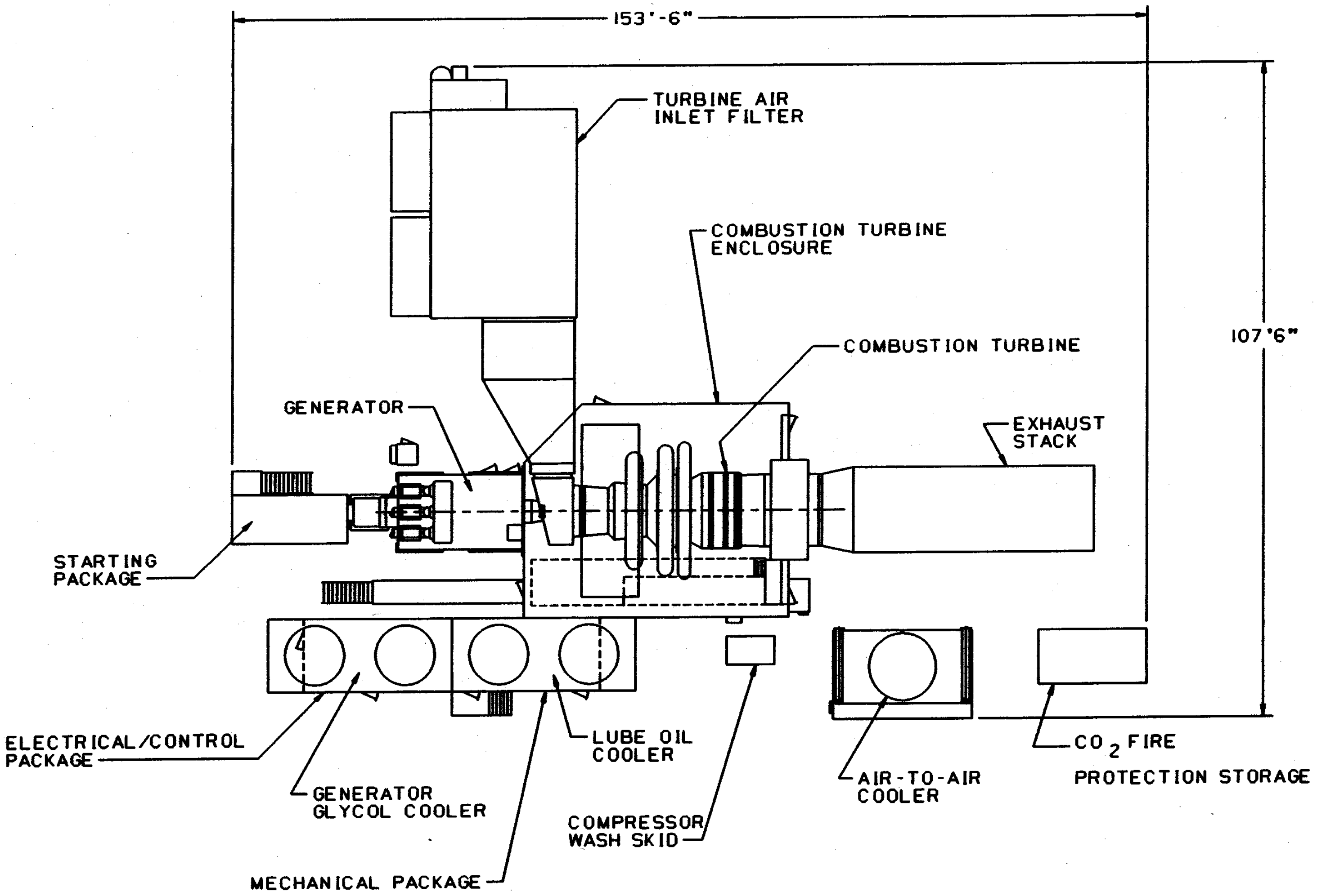


Figure 2.5.6.2 Plan View of Gas Turbine Installation

Fuel and Air Manifold Systems. The gas turbine piping and manifolding are configured to send compressed air to the boost compressor and receive syngas from the carbonizer and vitiated air from the PCFB boiler. Three toroidal ("ring") manifolds connect the plant piping for compressed air, syngas, and vitiated air, respectively, with the 16 gas turbine combustors. The major axis of each toroidal manifold is aligned with the major axis of the turbine, so that the manifold surrounds the turbine.

The modified W501G gas turbine burns syngas from the carbonizer with vitiated air from the PCFB, and also provides compressed air for the carbonizer and PCFB boiler. The 16 topping combustors in the gas turbine are connected to piping manifolds that transfer the syngas, vitiated air, and compressed air between the topping combustors and the large pipes (ducts) leading to and from the carbonizer and PCFB areas of the plant. The main piping sizes are summarized in Table 2.5.6.3.

Table 2.5.6.3 Air and Gas Piping Summary

	Units	*Compressed Air*	*Syngas*	*Vitiated Air*
Main Nozzles	No.	1	1	2
Main Nozzle Size	in.	36	42	48
Ring Manifold Size	in.	24	32	32
Combustor Spur Size	in.	8	24	24

The syngas inlet, vitiated air inlet, and compressed air exit nozzles of each combustor are connected to three separate toroidal ("ring") manifolds for syngas, vitiated air, and compressed air, respectively. The major axes of these manifolds are co-linear with the gas turbine centerline, as shown in Figure 2.5.6.3. Connections between the manifolds and the gas turbine are shown in cross-section in Figure 2.5.6.4.

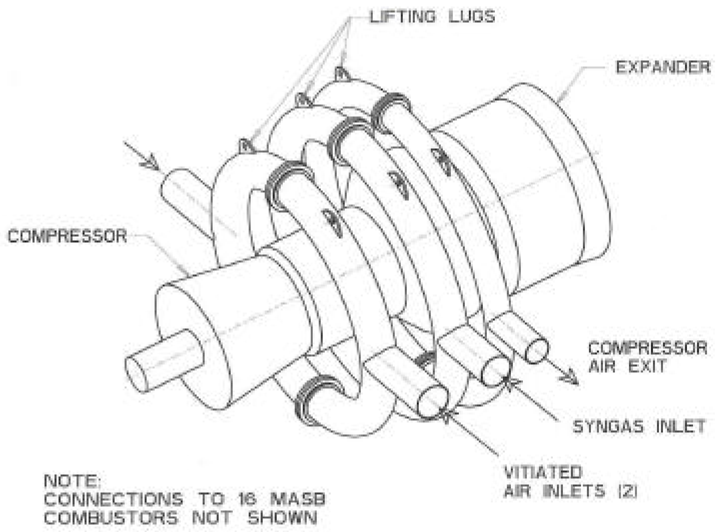


Figure 2.5.6.3 Hot Gas Manifold System

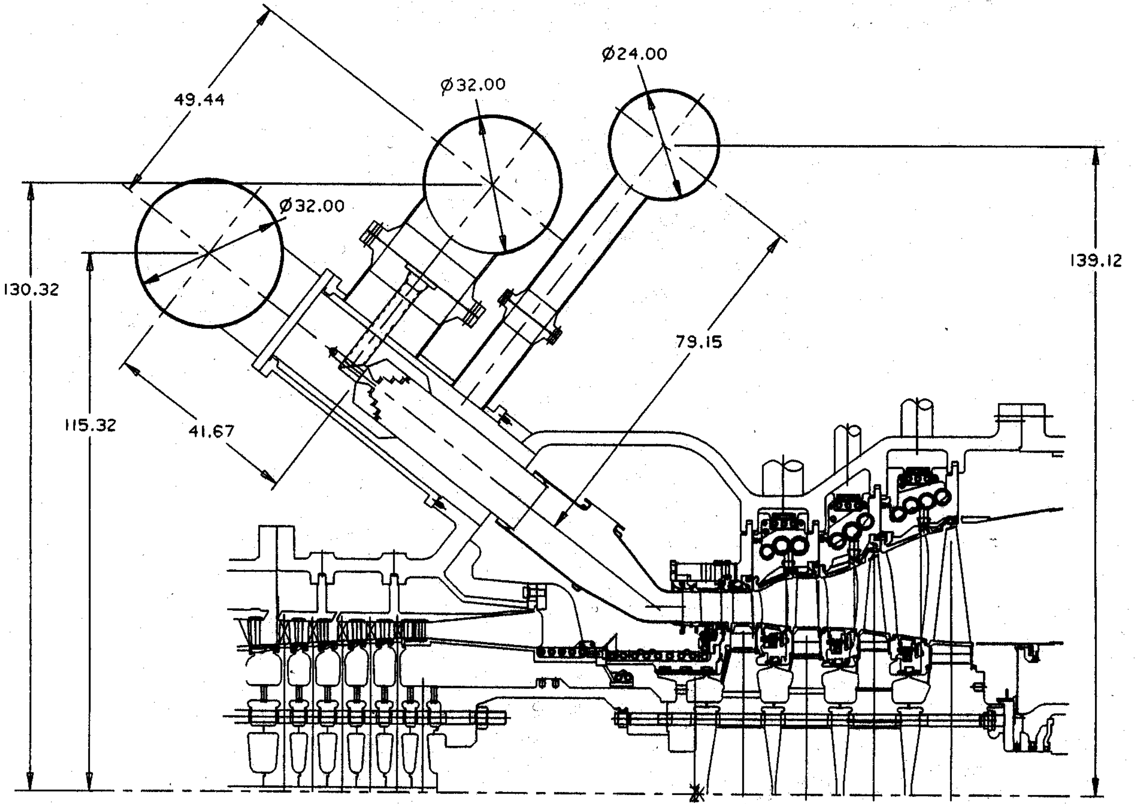


Figure 2.5.6.4 Syngas Combustor Manifold Connections

Protective Bypass Systems. Section 2.7.3 of this report includes the design basis for a control system to start the plant, operate at baseload, follow load, and shut the plant down in a safe and predictable manner. Equipment, piping, and major valves related to the startup, control, turndown, and shutdown of the baseline plant are shown schematically in Figure 2.5.6.5. Acronyms and abbreviations related to this figure are defined in Table 2.5.6.4, and both the plant and its control systems are defined at a conceptual level.

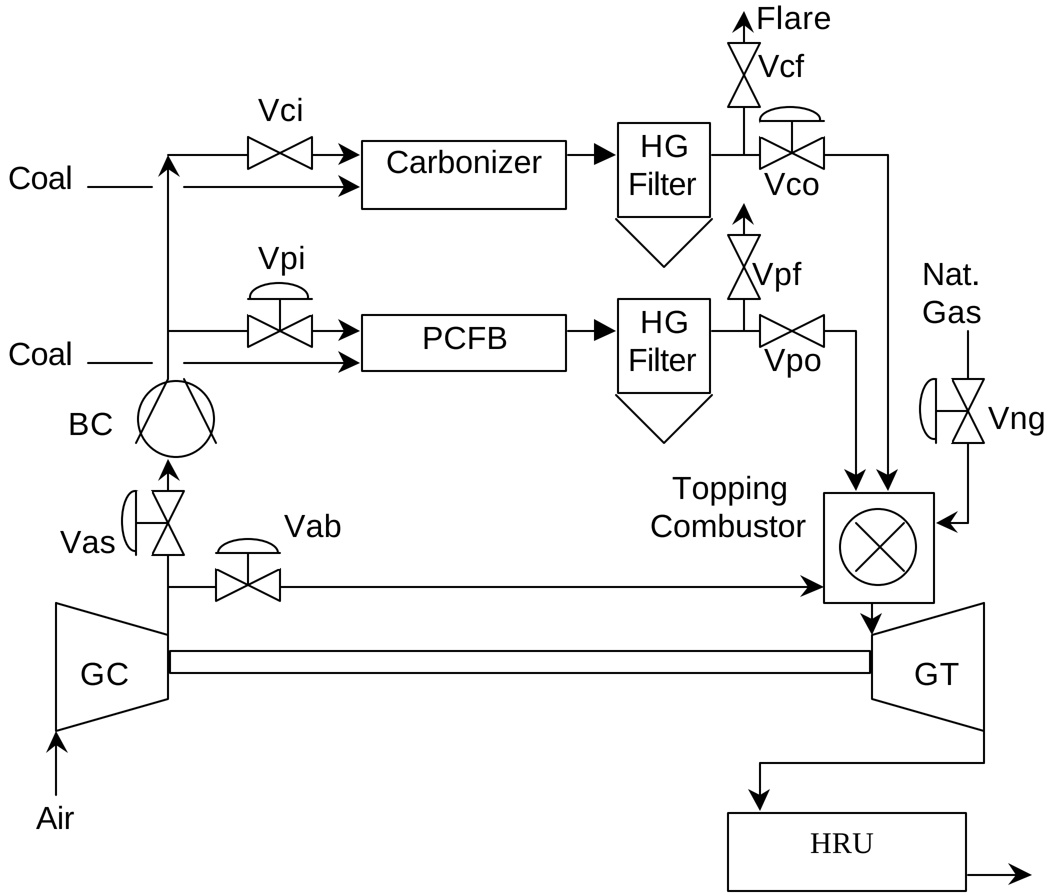


Figure 2.5.6.5 Plant Gas Flow Control Valves

Table 2.5.6.4 Valve and Equipment Abbreviations

BC	Boost Compressor to pressurize the PCFB
GC	Gas turbine compressor
GT	Gas turbine expander
HG	Hot Gas (Filter)
HRU	Heat Recovery Unit
PCFB	Pressurized Circulating Fluidized Bed
TC	Topping Combustor
Vab	Compressed air bypass valve
Vas	Compressed air supply valve
Vpi	PCFB air control valve
Vpf	PCFB (vitiated air) vent valve
Vpo	PCFB (vitiated air) outlet valve
Vci	Carbonizer air shutoff valve
Vcf	Carbonizer syngas flare valve
Vco	Carbonizer syngas control valve
Vng	Natural gas fuel control valve

The gas turbine is protected from damage during abnormal shutdowns by syngas piping and air bypass and isolation valving, the portions of the piping system that include valves Vas, Vab, Vpo, and Vco.

Syngas Piping and Valve System. The syngas piping is much larger than natural gas piping because the syngas heating value is lower and its temperature is higher. The syngas produced by the carbonizer has a combustible heating value only about 10 percent of that of natural gas, so the gas turbine requires a syngas flow rate more than eight times that of natural gas. Also, the temperature of the syngas entering the gas turbine is almost 1600°F, considerably hotter than the nominal 60°F temperature of natural gas, resulting in a specific volume almost three times that of natural gas and a volumetric flow rate about 24 times that of natural gas. The combination of high flow rate and high temperature leads to fuel gas piping and valving requirements that are more severe than the requirements for a natural gas-fueled turbine.

Syngas leaving the carbonizer hot gas filter flows through the carbonizer gas control valve Vco.

Air Bypass Piping and Valve System. The syngas system contains relatively large valves to regulate or shut off the flow of syngas to the topping combustors in the event of a plant upset, change of load, or loss of load. Because the PCFB boiler subsystem contains a relatively large volume of hot pressurized flue gas, an isolation valve, Vpo, is provided to stop the flow of this gas thereby shortening the gas turbine coast down period during a trip.

Loss-of-Load Protection. The sudden loss of electrical load causes rapid acceleration of the gas turbine, which must be stopped in order to prevent catastrophic damage.

At the first instant of load loss, the syngas valve (Vco) quickly closes to interrupt gas flow to the turbine. Upstream of the carbonizer, air is prevented from entering by the closing of valve Vci. At the same time, the compressed air bypass valve (Vab) opens as the compressed air supply valve (Vas) and PCFB air control (Vpi) and outlet (Vpo) valves close, interrupting the hot vitiated air flow to the turbine and bypassing cooler compressed air to the topping combustor. Simultaneous with the operation of the above valves, all solid feeds to the carbonizer and PCFB boiler are stopped and these units are bottled up. Carbonizer syngas flare valve Vcf and PCFB vent valve Vpf are used to depressure these units at controlled rates. By adjusting the air bypass valve (Vab), the compressor pressure ratio is elevated, increasing compressor work to aid in the deceleration process.

A detailed analysis of a loss of load event is given in [2-1] for a 2nd Generation PFB plant operating with a 501F gas turbine; that analysis indicated that the syngas control valve Vco required a 0.6 second closure time and that a leakage rate up to 10 percent of full load flow could be tolerated. The higher temperature of the syngas and vitiated air streams make these valves non-conventional, and an R&D plan for developing them was formulated.

Section 2.7.3 discusses the action of the Figure 2.5.6.5 valving in greater detail for start up, shutdown, load follow-up, and loss of load.

2.5.7 Ceramic Candle Filters

2.5.7.1 Filter Design Configuration

The hot gas filter used for the carbonizer and PCFB boiler utilizes a Siemens Westinghouse configuration and is shown schematically in Figure 2.5.7.1. Each filter uses ceramic candle filter elements, 1.5 m long and 60 mm in outer diameter. The hot gas filter consists of stacked arrays of filter elements supported from a common tube sheet structure. The arrays are formed by attaching individual candle elements (Item 1) to a common plenum section (Item 2). Each candle element has an attached "fail-safe" or "safe guard" device that limits the gas flow and dust emission from a candle if it is damaged. All the gas filtered by the candles comprising this single array is collected in the common plenum and discharged through a pipe to the clean side of the tube sheet structure. Each array of filter elements is reverse-cleaned from a single pulse nozzle source. The individual plenum assemblies (or arrays) are stacked vertically from a common support structure (pipe), forming a filter cluster (Item 3). The individual clusters are supported from a common, high alloy tube sheet structure and expansion assembly (Item 4) that spans the pressure vessel and divides the vessel into its “clean” and “dirty” gas sides.

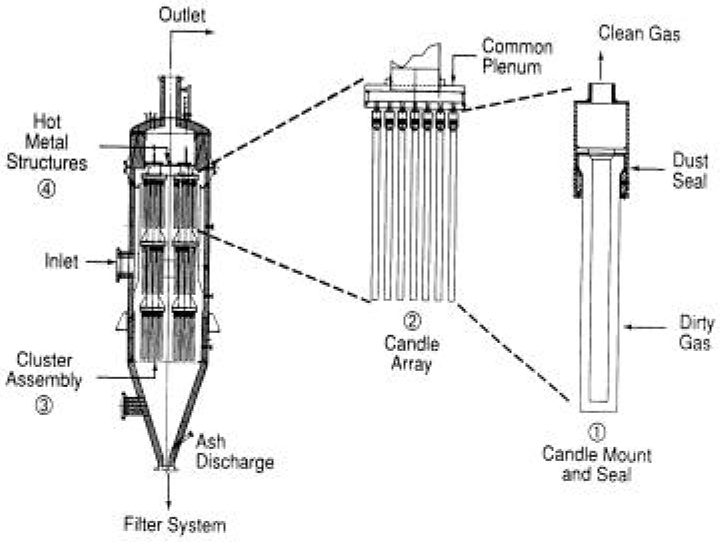


Figure 2.5.7.1 SWPC Candle Filter System

Each cluster attaches to the tube sheet structure by a specially designed split ring assembly. The cluster is free to grow down at temperatures. The plenum discharge pipes ducting the filtered gas to the clean gas side of the tube sheet structure are contained within the cluster support pipe and terminate at the tube sheet. Each discharge pipe contains an eductor section. Separate pulse nozzles are positioned over each eductor section. The eductors assist pulse cleaning. During cleaning, the pulse gas is contained within and ducted down the discharge pipe and pressurizes the respective plenum section.

The plenum assembly and cluster (stacked plenums) form the basic modules needed for constructing large filter systems for electric utility power generation systems. The scale-up approach is:

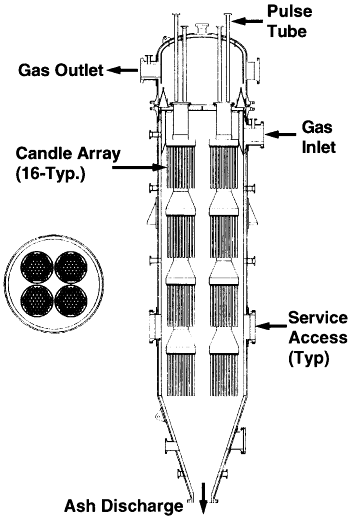
- Increasing plenum diameter (more filter elements per array)
- Increasing the number of plenums per cluster
- Increasing the vessel diameter to hold more clusters

In general, vessel diameter will be limited by the un-cooled tube sheet structure and the desire to shop fabricate the pressure vessel.

Clay bonded silicon carbide (SiC) candle filters are commercially available. The structure of these elements is mainly a coarse-grained SiC bonded by a clay-based binder. Each element is provided with a fine grained SiC or aluminosilicate fiber outer skin that serves as the filtration surface.

Alternate, oxide-based ceramic materials are also being developed for ceramic barrier filter application. Candle filter elements have been constructed using a homogeneous structure that is an alumina/mullite matrix containing a small percentage of amorphous (glass) phase.

Each filter vessel used by the plant possesses the general arrangement shown in Fig. 2.5.7.2. The filter vessel holds 784 candle elements, arrayed on four clusters. Each cluster contains 187 candles distributed on four plenums, and the filter is designed for ease-of-maintenance. Access into the filter body is provided by four, 36-inch diameter manways. Two diametrically opposite manways are positioned between clusters to access the top level of plenums. Similarly, two diametrically opposite manways are positioned between clusters to access the lower middle level of plenums. The access and maintenance arrangement is illustrated in Figure 2.5.7.3. At any given platform location, all filters for two adjacent plenums are accessible by rotating the associated cluster. Such rotation is accomplished by entering the vessel head above the tubesheet, disengaging the cluster top flange from the tubesheet and with standard manual rigging attached between the vessel head and cluster top flange, lifting and rotating the cluster.



- **10 Ft. Dia. (3.05 m) Refractory Lined Vessel**
- **Contains 748 (1.5 Meter Long) SiC Candle Elements**
- **Candle Elements are Arrayed on Sixteen (16) Plenum Assemblies Containing from 42 to 61 Elements**
- **Backpulse Cleaning – Recycled Fuel Gas**

Figure 2.5.7.2 Filter Vessel Arrangement

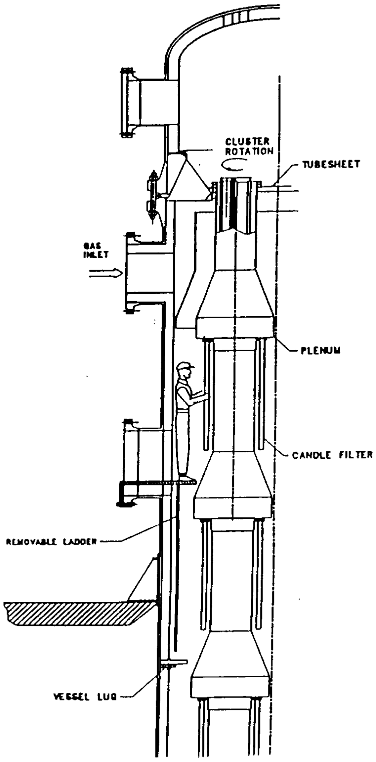


Figure 2.5.7.3 Hot Gas Filter Maintenance Features

Carbonizer Filter System. The carbonizer filter system requires four filter vessels operating in parallel to clean the syngas of particulate; the system is designed for a nominal operating temperature of 1600°F, with inlet gas pressure of 294 psig, and inlet dust loading of 6,800 ppmw. The hot gas inlet and outlet nozzles are radially directed with horizontal orientations. The pressure vessels are refractory-lined with 6.75 inch thickness of a 2-layer castable, and a metal liner is placed in the conical hopper section of the vessel to assist ash flow from the hopper. The pulse gas control skid is designed for high reliability with automatic switching to spare pulse valves in the event a pulse valve fails. Similarly, the pulse gas compression system is designed with a spare compressor for nominal pulse gas compression needs, and both compressors can be operated simultaneously f high pulse gas rates are required to recover from an upset condition. The vessel and its pulse control skid are illustrated in Figure 2.5.7.4. The main characteristics of the carbonizer filter system are summarized in Table 2.5.7.1.

Table 2.5.7.1 Carbonizer Filter Characteristics

number of filter vessels	4
number of pulse control skids	4
number of pulse gas compressors	2
vessel OD (ft)	10.6
vessel height (ft)	58
head height (ft)	11.3
body height (ft)	46
gas inlet nozzle nominal size (in.)	38
gas outlet nozzle nominal size (in.)	34
solids drain nozzle nominal size (in.)	30
vessel empty wt, each (tons)	134
vessel loaded wt, each (tons)	163
pulse control skid floor area, each (ft^2)	350

The performance of the carbonizer filter system is summarizer in Table 2.5.7.2, with the performance estimates based on carbonizer filter ash properties (permeability, bulk density, cleaning behavior) measured in prior carbonizer pilot plant testing. The face velocity is relatively low and well within the experience of testing for such filter systems. The ash storage capacity represents the maximum time that the filter can operate without drainage of ash from the hopper in the event a plugged hopper outlet nozzle or a stoppage of the ash removal equipment occurs. The pulse cleaning is conducted on a uniformly-distributed schedule that results in relatively constant filter pressure drop behavior. The filter can be pulse cleaned over a range of acceptable pulse cleaning frequencies to provide nozzle-to-nozzle pressure drop control. Both maximum and minimum pulse frequency conditions are listed.

Table 2.5.7.2 Carbonizer Filter Performance

face velocity (ft/min)	4.3
vessel ash storage capacity (hr)	4.3
maximum pulse frequency (1/hr)	3.1
nozzle-to-nozzle trigger pressure drop (psi)	3.3
nozzle-to-nozzle baseline pressure drop (psi)	3.1
pulse gas consumption (lb/hr)	1360
gas temperature loss (°F)	16
minimum pulse frequency (1/hr)	2.0
nozzle-to-nozzle trigger pressure drop (psi)	3.9
nozzle-to-nozzle baseline pressure drop (psi)	3.6
pulse gas consumption (lb/hr)	590
gas temperature loss (°F)	14

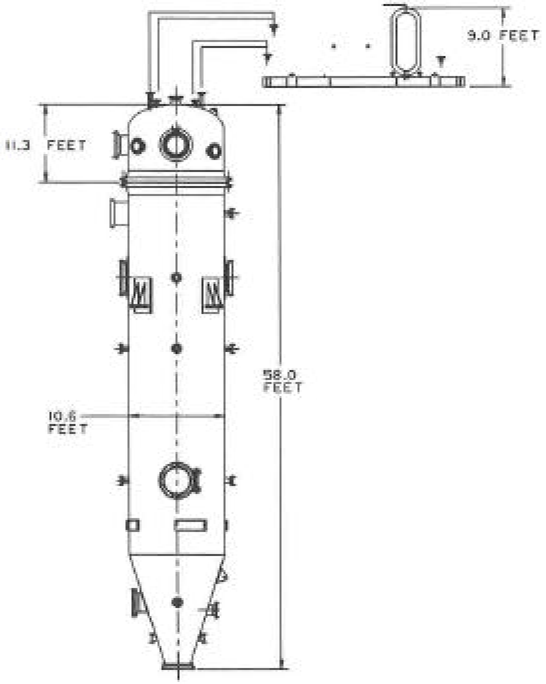


Figure 2.5.7.4 Carbonizer Filter and Pulse Control Skid

PCFB Filter System. The PCFB filter system requires four filter vessels operating in parallel to clean the vitiated air of particulate; the system is designed for a nominal operating temperature of 1600°F, inlet gas pressure of 283 psig, and inlet ash loading of 44,600 ppmw. The vessel design features and the equipment redundancy philosophy is analogous to that described for the carbonizer filter system. The vessel and its pulse control skid are illustrated in Figure 2.5.7.5. The main characteristics of the PCFB filter system are summarized in Table 2.5.7.3. Each PCFB filter vessel is slightly larger than each carbonizer filter vessel and appropriate metal alloys have been selected for the construction of the high-temperature filter vessel internal components.

The performance of the PCFB filter system is summarized in Table 2.5.7.4. The performance estimates are based on PCFB filter ash characteristics measured in prior pilot PCFB filter tests. The face velocity is higher than in the carbonizer filter, but is well within the operating experience of PCFB test filters. The vessel ash storage capacity is relatively small, so care must be taken to keep the ash hopper drain functioning. Because of the high inlet ash loading, the pulse frequencies and pulse gas consumption rates are higher than the carbonizer filter.

Table 2.5.7.3 PCFB Filter Characteristics

number of filter vessels	4
number of pulse control skids	4
number of pulse gas compressors	2
vessel OD (ft)	10.9
vessel height (ft)	61
head height (ft)	12.2
body height (ft)	48.7
gas inlet nozzle nominal size (in.)	44
gas outlet nozzle nominal size (in.)	40
solids drain nozzle nominal size (in.)	38
vessel empty wt, each (tons)	146
vessel loaded wt, each (tons)	175
pulse control skid floor area, each (ft^2)	350

Table 2.5.7.4 PCFB Filter Performance

face velocity (ft/min)	8.1
vessel ash storage capacity (hr)	0.6
maximum pulse frequency (1/hr)	8.0
- nozzle-to-nozzle trigger pressure drop (psi)	5.2
- nozzle-to-nozzle baseline pressure drop (psi)	5.0
- pulse gas consumption (lb/hr)	4911
- gas temperature loss (°F)	11
minimum pulse frequency (1/hr)	3.9
- nozzle-to-nozzle trigger pressure drop (psi)	6.0
- nozzle-to-nozzle baseline pressure drop (psi)	5.6
- pulse gas consumption (lb/hr)	1432
- gas temperature loss (°F)	8

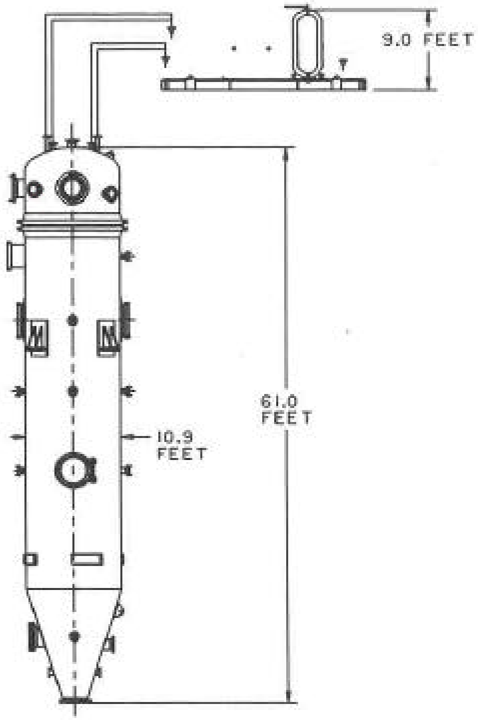


Figure 2.5.7.5 PCFB Filter and Pulse Control Skid

2.5.7.2 Hot Gas Piping

The plant incorporates a significant amount of large diameter hot gas piping to connect the various components into a complete, functional system. Some of this piping contains gases at temperatures up to 1700EF and at pressures of several hundred psig. Because of the high gas temperatures involved, the hot gas piping contains an internal 9-inch thick refractory lining consisting of 3 inches of hard facing/erosion resisting layer backed by a 6-inch thick insulating layer.

The clean gas lines from the barrier filters to the gas turbine (syngas and vitiated air) are lined with stainless steel or Hastelloy in a thin gauge sheet to protect the turbine from spalling fragments of the refractory material. The remaining refractory lined pipe segments, upstream of the barrier filters, do not incorporate the liner. The carbon steel outer piping provides the pressure retaining integrity of the refractory lined system.

Table 2.5.7.5 Major Pipe System Operating Parameters for the Baseline Plant

FLUID	FROM-TO	OPERATING PRESS, PSIA	OPERATING TEMP, F	FLOW RATE, LB/H	DELTA P, PSI
Compressed Air	Compressor Discharge-Boost Compressor	278.6	810.9	2,273,862	8.6
Compressed Air	Boost Compressor-Carbonizer	307.8	599.0	622,805	5.4
Syngas	Carbonizer-Topping Combustor	298.8	1686.4	745,552	23.0
Compressed Air	Boost Compressor-PCFB	307.8	599.0	1,631,364	10.0
Vitiated Air	PCFB-Topping Combustor	286.9	1600.0	1,839,059	11.1
Compressed Air	Boost Compressor-Solids Feed System	354.4	133.8	165,694	15.0

Based on the equipment arrangement shown in the plant general arrangement drawings and the compressed air, syngas, and PCFB vitiated air piping isometric drawings shown in Figures 2.5.7.6 through 7.8, an analysis of piping pressure drops was performed. The results of this analysis (see Table 2.5.7.5) enabled selection of appropriate pipe diameters; specification of materials and wall thickness followed, based on normal design practice for power plant pressure piping. Initial estimates of pipe sizes was based on selection of an entrance Mach Number into each pipe segment of 0.07. Experience in piping system design for compressible fluids (gases) indicates that this is a reasonable threshold value; higher values for the entrance Mach No. tend to produce choking by friction (Fanno Line effects), while lower values may lead to unnecessarily large and expensive pipe selections.

The entrance Mach No. selection enabled sizing of the pipe for each line segment, and calculation of pressure drops. Some minor adjustments were made to pipe diameters to utilize standard pipe sizes; gas velocity and Mach No. will thus vary slightly from the nominal 0.07 value. Table 2.5.7.6 presents pipe size and specification data for representative major pipe runs identified in Table 2.5.7.5.

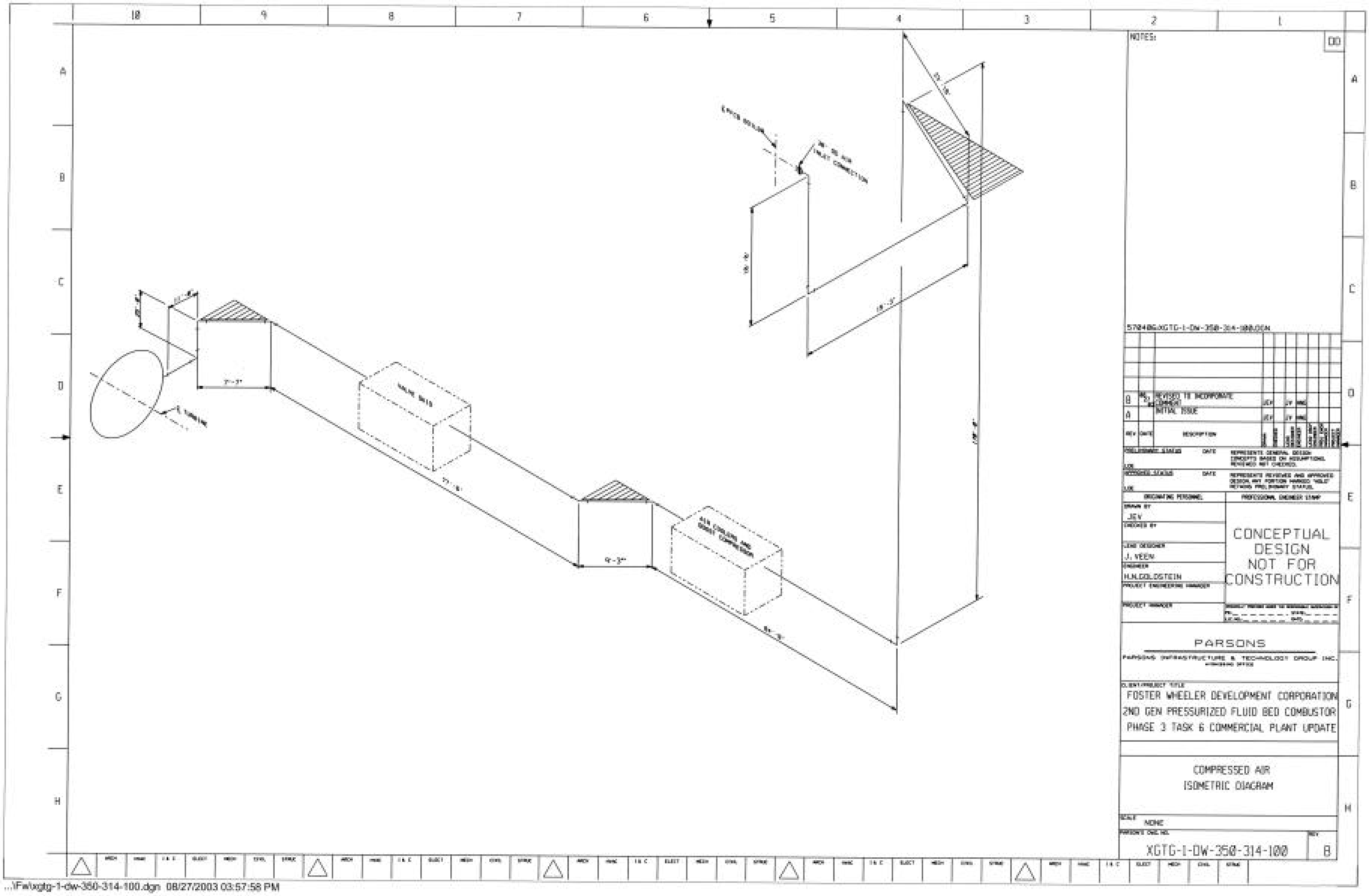


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Figure 2.5.7.6 Air Piping from Gas Turbine to PCFB Boiler

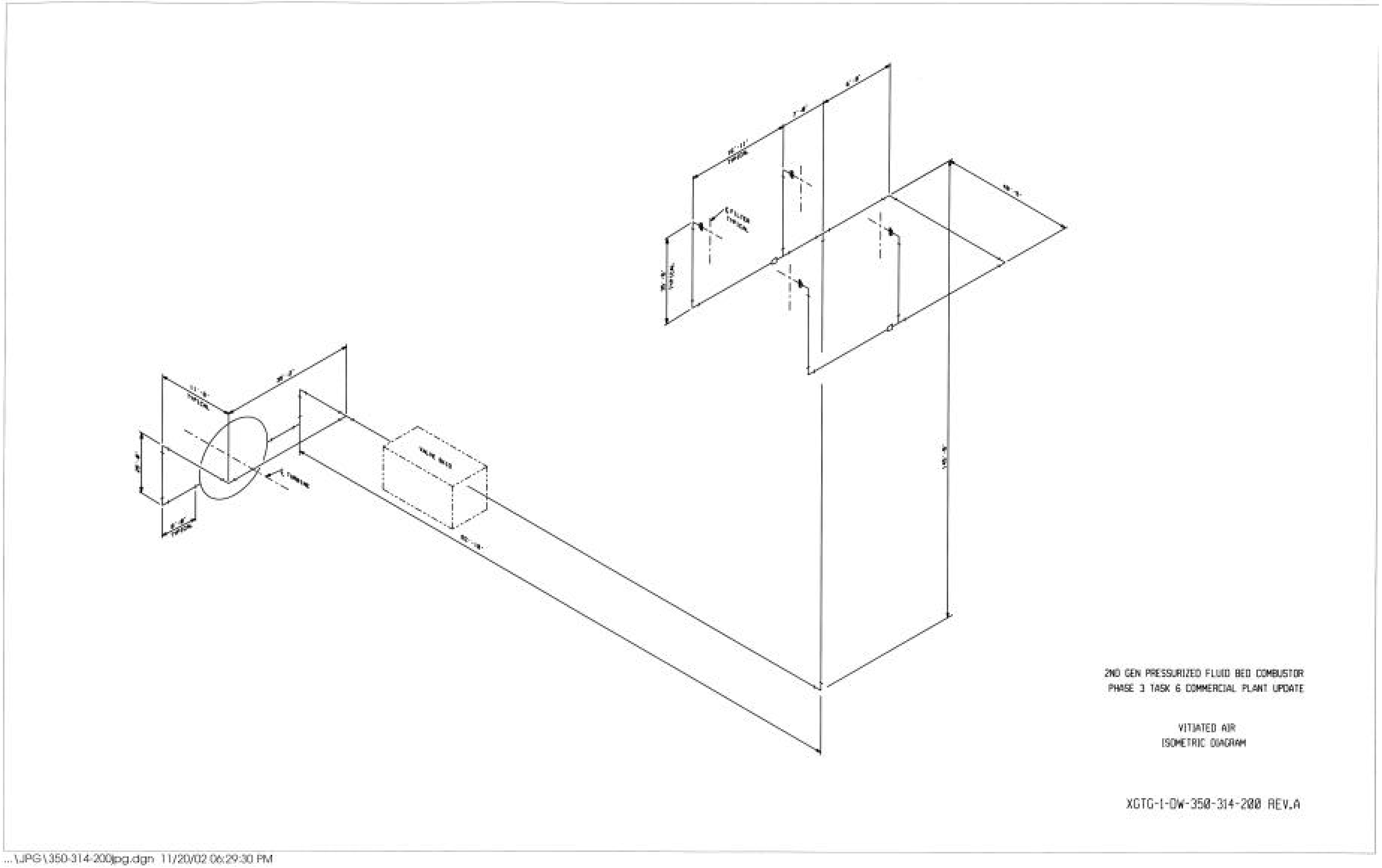

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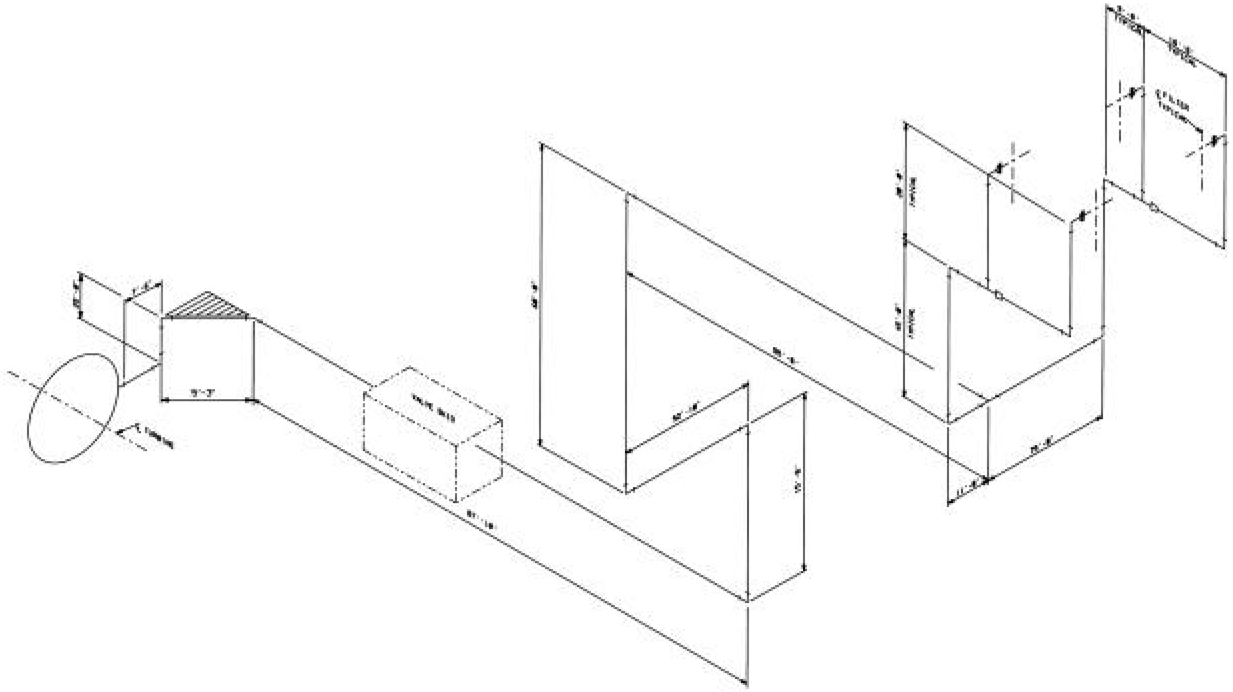
Figure 2.5.7.7 Vitiated Air Piping from Filters to Gas Turbine



2ND GEN PRESSURIZED FLUID BED COMBUSTOR
PHASE 3 TASK 6 COMMERCIAL PLANT UPDATE

SYNGAS
ISOMETRIC DIAGRAM

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Figure 2.5.7.8 Syngas Piping from Filters to Gas Turbine

Table 2.5.7.6 Major Pipe System Design Parameters for the Baseline Plant

FLUID	FROM-TO	DESIGN PRESS., PSIG	DESIGN TEMP., F	ID, IN.	OD, IN.	$T_{(WALL)}$, IN.	MATERIAL
Compressed Air	Compressor Discharge-Boost Compressor	300	900	41.0	42.0	0.50	A691 Gr P22
Compressed Air	Boost Compressor-Carbonizer	325	650	17.25	18.0	0.375	A106 Gr B
Syngas	Carbonizer-Topping Combustor	315	1700	29.0	48.0	0.50	A672 Gr B70 Refractory Lined
Compressed Air	Boost Compressor-PCFB	325	650	31.0	32.0	0.50	A672 Gr B70
Vitiated Air	PCFB-Topping Combustor	300	1650	40.5	60.0	0.75	A672 Gr B70 Refractory Lined
Compressed Air	Boost Compressor-Solids Feed System	325	650	11.25	12.0	0.375	A106 Gr B

Although piping thermal expansion stress analyses were not conducted, the piping layout/ routing shown on the plant general arrangement drawings is based on experience with hot large diameter pipe on other power plant designs and is believed to be reasonable.

2.5.7.3 Stack

The stack design is based on the following:

1. Stack gas velocity at the top is limited to a nominal 100 ft/s
2. Draft loss is limited to 2.0 in H_2O
3. Gas flow is 4,281,300 lb/h of gas at 1 atm. and 274F.

The stack height is 300 feet; the diameter at the top is 18 feet and it tapers to a 29 foot. diameter at the bottom. The stack is constructed of reinforced concrete with a steel liner. Openings in the shell are provided for access doors, flues, and windows. The stack is complete with internal ladders, platforms, lightning protection, internal lighting and power and aviation obstruction lighting.

2.5.8 Syngas Bypass and Flare System

A flare stack is provided to allow safe discharge/venting of carbonizer syngas during start-up, shutdown, and upset conditions. The flare consists of a 70-in. diameter, 55-ft tall self-supporting stack. The stack is lined for high-temperature service, and it includes a 70-in. flare tip, a manual flame-front generator, four flare pilots, and pilot flame monitoring instrumentation. The stack is in a remote, open area, between the river and the main plant, with a clear radial area of 150 ft surrounding it. The syngas discharges to the flare system via valve V_{cf} shown in Figure 2.5.6.5. A smaller, secondary line not shown in Figure 2.5.6.5 is used to vent syngas between the emergency shut-off valve and the gas turbine topping combustor. Any other streams of combustible gases that require discharge are also discharged to the flare.

2.5.9 Steam Turbine/Generator, Condenser, and Auxiliaries

Steam Turbine. The plant uses a 2400 psig/1050ºF/1050ºF/2½ in. Hg.(a) steam turbine that requires only three extraction openings rather than the usual five to seven.

The steam turbine is a tandem compound 3600 rpm machine with single HP and IP turbine sections, mounted in an opposed manner in a single casing. The LP turbine section is contained in one separate two-flow casing, with last-stage bucket length of 33 inches. The LP turbine exhausts laterally into the condenser, which is split into two half-sized units, one on each side of the LP turbine casing. The three machine elements (HP/IP and two LP sections) drive a 60 Hz synchronous generator through a common shaft. The generator is hydrogen cooled, and is equipped with a static exciter. The standard turbine auxiliaries, including gland steam condenser, lube oil reservoir and conditioner, oil and generator hydrogen coolers, electrohydraulic control system, etc., are provided on ancillary skids and packages.

2.5.10 Steam and Feedwater

The steam and feedwater system (Figure 2.5.10.1) uses conventional steam-based power generating equipment, and the steam system produces approximately 52 percent of the electrical output of the plant. Included in this section are descriptions of the system function, design criteria, and major equipment.

System Functions. The feedwater system furnishes condensate-quality feedwater (cleaned, preheated, and pressurized to the level necessary for providing steam to the steam turbine/ generator) to the PCFB boiler and compressor air cooler drums for evaporation and eventual superheating and reheating. It is then sent to the steam turbine/generator. After the usable energy is converted into mechanical energy in the turbine, the exhaust steam is condensed, ready for recirculation.

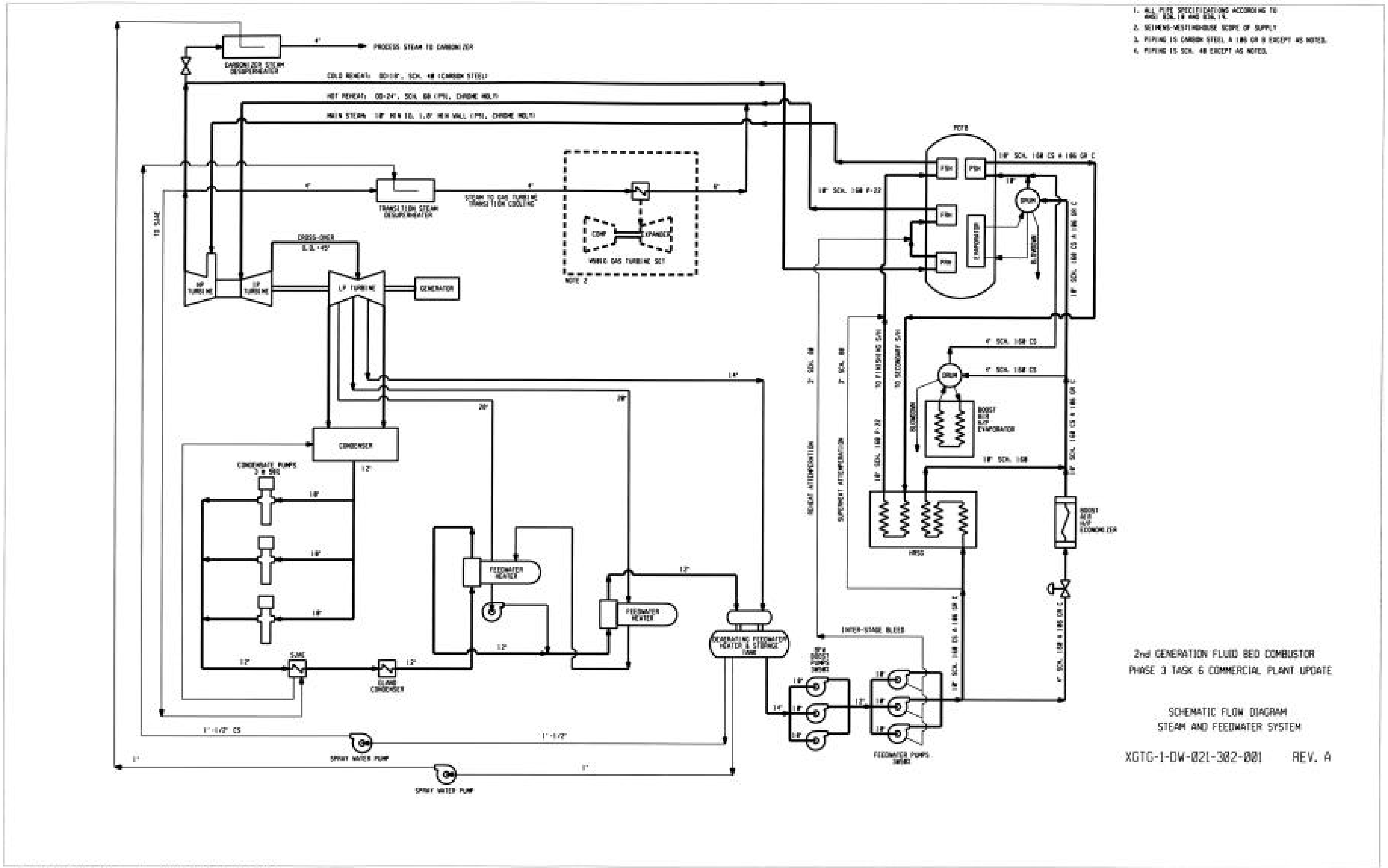

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Figure 2.5.10.1 Steam and Feedwater Systems

Design Criteria. Design criteria for this system are shown on the plant heat balance (Figure 2.2.0.2), which defines the flows, pressures, and temperatures necessary to produce the electrical power output required of the plant. The nominal turbine steam inlet pressure is 2400 psig, with turbine main and reheat steam temperatures of 1050°F. The condenser pressure is 2-1/2 inches of Hg. absolute. Although the steam pressure is normal for a baseload electric utility plant, it is unusually high for a combined-cycle-type system (usual ratings would be either 1450 or 1800 psig.). Since the gas turbine HRU provides only economizer and primary superheat duties, the higher operating pressure is not expected to cause any heat recovery technology problems.

Feedwater heating is accomplished in three stages using conventional feedwater heaters supplied with steam from three extraction points on the low-pressure turbine at 4.1 and 14.9 psia for two closed heaters and 28.2 psia for a direct-contact deaerating heater. A portion of the feedwater by passes the closed heater and is routed through the ash coolers for recovery of ash heat for use in the power cycle. Additional feedwater heating is accomplished in two economizer units: a unit that cools compressor discharge air en route to the main boost compressor and economizer surface in the HRU that recovers gas turbine exhaust thermal energy.

Major Equipment. This section lists and describes the major equipment contained in the steam and feedwater system. Some equipment shown on the system diagram (Figure 2.5.10.1) is not listed since, by definition, it is part of a different system. The unlisted equipment and the location of descriptions are:

Equipment	Section
Steam turbine/generator	2.5.9
PCFB boiler	2.5.5

- Steam Condenser (E-304A). The steam condenser condenses steam exhausted from the main steam turbine/generator and deaerates the condensate.

Steam flow, lb/h	1,261,900
Duty, 10^6 Btu/h	1206
Back pressure, in. Hg absolute	2.5
Circulating water temperature inlet, EF	85
Effective tube length, ft-in.	44 - 3
Number of tubes	9400
Tube material	Titanium
Velocity, ft/s	7.5
Circulating Water, gal/min	140,000
Surface, ft^2	109,000

- Condensate Pumps (P-311A. B. and C). The condensate pumps take water from the steam condenser and raise the water pressure to the level necessary to enter the deaerator. Three 50 percent pumps are provided.

Type pump	Vertical Canned
NPSH	0 at pump suction
Total Hydraulic Head, ft	375
Stages	6
Bowl size, in.	12
Speed, rev/min	1770
BHP	125

- Condensate Demineralizer (WS-305A and B). Particulates and contaminants are continuously removed from the condensate by the condensate demineralizers. Two 100 percent capacity units are provided.

Diameter, ft	8.5
Unit capacity, gal/min-ft^3	50
Capacity, gal/min	2835
Regeneration	External
Design pressure, psig	150

- Heater Drain Pumps (P-309A and B). The heater drain pumps pump the drains from the lowest pressure feedwater heater forward to join the condensate leaving the first stage heater. Two 100 percent pumps are provided.

Type pump	Vertical Canned
Stages	1
NPSH required, ft	0 at pump suction
Total Hydraulic Head, ft	375
Capacity, gal/min	160
Speed, rev/min	1750
BHP	25

- Feedwater Heater (E-307A). The temperature of the feedwater is raised in a closed feedwater heater for one stage of regenerative feedwater heating.

Steam side:	
Pressure, psia	4.1
Enthalpy, Btu/lb	1085.6
Flow, lb/h	29,542
Water side:	
Pressure, psia	200
Inlet Temperature, EF	109
Flow, lb/h	1,219,715

- Feedwater Heater (E-307A). The temperature of the feedwater is raised in a closed feedwater heater for one stage of regenerative feedwater heating.

Steam side:	
Pressure, psia	14.9
Enthalpy, Btu/lb	1168
Flow, lb/h	50,162
Water side:	
Pressure, psia	200
Inlet Temperature, EF	146
Flow, lb/h	909,889

- Deaerator (E-308A). The last stage of feedwater heating before the steam generators is an open, direct-contact heater with a deaerating function. One full-size deaerator is provided.

Steam flow, lb/h	45,676
Steam pressure, psia	28.2
Steam enthalpy, Btu/lb	1216.4
Water flow, lb/h	909,889
Inlet water temperatures, EF	203.5
Outlet water temperature, EF	242

- Feedwater Booster Pumps (P-312A, B, and C). Feedwater pressurizing is broken into two physical stages. The feedwater booster pumps provide the first stage, and provide the main feedwater pumps with adequate NPSH. Three 50 percent pumps are provided.

Capacity, gal/min	1800
Total Hydraulic Head, ft	400
NPSH required, ft	20
Pump type	Horizontal split case
Number of stages	1
BHP	250
Speed, rev/min	3550

- Feedwater Pumps (P-310A, B, and C). Three 50 percent pumps are provided.

Capacity, gal/min	1800
Total Hydraulic Head, ft	7200
NPSH required, ft	30
Pump type	Barrel Type
Number of stages	9
BHP	4000
Speed, rev/min	3550

- Heat-Recovery Unit (CB-302A). Heat is recovered from the exhaust of the combustion turbine and used to heat feedwater and superheat steam as follows:

Gas Side:	
Flow, lb/h	4,281,300
Temperature In, EF	1129.6
Temperature Out, EF	274
Water In:	
Flow, lb/h	1,192,863
Pressure, psia	3070
Temperature, EF	247.6
Water Out:	
Flow, lb/hr	1,192,863
Pressure, psia	2770
Temperature, EF	650
Steam In:	
Flow, lb/h	1,342,779
Pressure, psia	2694.2
Temperature, E F	690.0
Steam Out:	
Flow, lb/h	1,342,779
Pressure, psia	2618
Temperature, E F	970.0

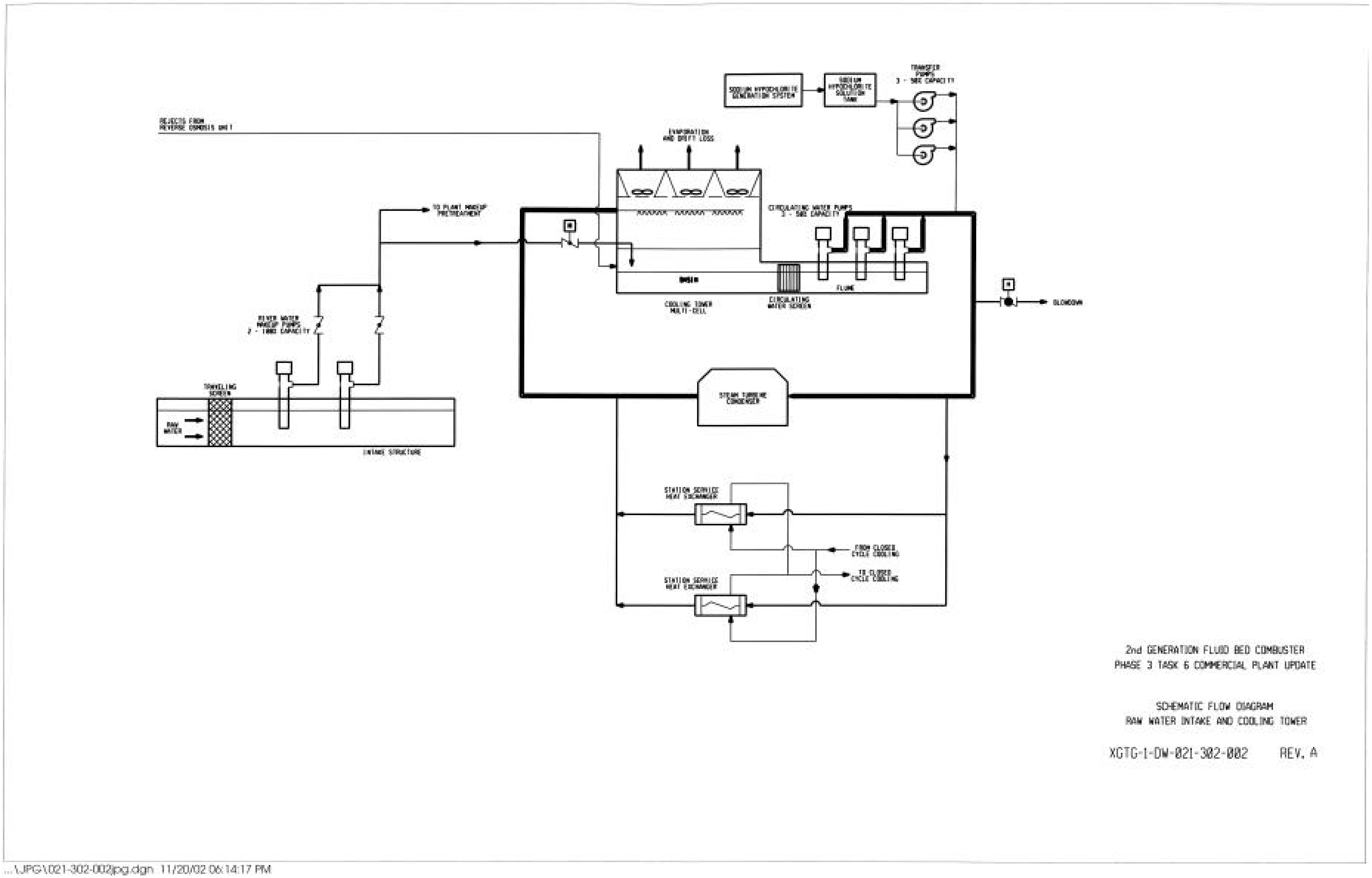
2.5.11 Cooling Water System

System Function. The cooling water system (Figure 2.5.11.1) is designed to supply cooling water to the condenser of the steam turbine/generator. The water is pumped from a cooling tower flume by three 50% capacity, vertical, circulating water pumps, which discharge into a common circulating water pipe. The water flows through the condenser to the cooling tower and back to the flume for reuse.

Design Criteria. The circulating water flume is designed for a velocity of 1 ft/s and uniform distribution to each pump. The flume and cooling tower basin are constructed of reinforced concrete. The flow velocity in the pump discharge piping is limited to 12 ft/s.

The makeup to the cooling tower is river water, which is drawn into the system by vertical wet-pit-type pumps through trash racks and traveling water screens.

The circulating water system is also designed to supply cooling water to two station-service heat exchangers that provide the cooled condensate through the closed-cycle system to all major equipment heat exchangers in the main turbine generator and boiler areas.



2nd GENERATION FLUID BED COMBUSTER
PHASE 3 TASK 6 COMMERCIAL PLANT UPDATE

SCHEMATIC FLOW DIAGRAM
RAW WATER INTAKE AND COOLING TOWER

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Figure 2.5.11.1 Cooling Water System

Major Equipment. Major equipment in the cooling water system consists of:

- Cooling Tower. A multi-cell, induced-draft cooling tower provides the means to cool 140,000 gal/min water at 103°F inlet temperature and 85°F outlet temperature with an atmospheric wet bulb temperature of 77°F.

  The warm water leaving the condenser passes through the cooling tower to transfer heat to the atmosphere by evaporation into the airflow induced by the fans. Drift eliminators remove entrained water droplets.

  The cooling tower basin is designed to resist the maximum uplift of soil and water when completely empty. Makeup water (to replace evaporated water, blow-down, and drift) enters the cooling tower basin through a motor-operated, automatic, level-control valve.

  Cooling tower effluent water flows through a flume to the circulating water pumps. This flume includes a local-level indicator and a level transmitter to notify the control room of the level and to transmit a high- or low-level alarm.

- Circulating Water Screens (SR-304A and B). A double set of 1/2-in. mesh, removable screens, which remove large objects such as leaves, sticks, logs, and ice, protects the circulating water pumps and condenser tubes from plugging. These screens, installed upstream of the pump suction, are galvanized iron. They slide into structural steel channels and can be pulled out one at a time for cleaning. Although they are designed to withstand a differential pressure of 3.5 ft of water, normal operation is with less than 6 in. of water differential.

- Circulating Water Pumps (P-304A. B. and C). Three identical, circulating water pumps are provided, each 50 percent of the design capacity. The pumps are vertical, with above-surface discharge and pull-out construction. One pump can be used for start-up; two are required for design load. Each pump has a motor-operated discharge butterfly valve. The pump discharge valve is interlocked with the pump motor starting circuit so that the valve is first opened approximately 15 deg. The motor starts automatically when the valve reaches that position. After the pump is up to speed, the system is full, and stable flow is established, the valve is opened to 90 deg. On shutdown, the valve closes to 15 deg and then trips to the closed position after the motor has stopped. To avoid hydraulic surges, the valve closes automatically upon loss of power.

- Station-Service Heat Exchangers (E-308A and B). Two 50 percent capacity plate and frame type station-service heat exchangers are required for full load, although only one heat exchanger is required during winter. The circulating water passes through the one side of the heat exchanger, and the filtered makeup water passes through the other side.

- Traveling Water Screens (SR-303A and B). Two vertical, traveling, water screens clean the plant makeup water obtained from the river. Each screen is furnished with galvanized steel baskets. The main frame of the screen is two-post construction. Overlapping side-guard seals are designed to prevent the passage of debris around the outside of the screen frame. The screen is motor-driven through an enclosed, gear-type speed reducer. The slow-speed shaft of the reducer turns the screen head shaft through a chain drive.

- River Water Makeup Pumps. One 100 percent capacity, vertical, wet-pit-type makeup water pump runs continuously at all loads and during shutdown when cooling water is required. A second 100 percent capacity pump is provided for standby.

2.5.12 Cycle Makeup Pretreatment System

The primary function of the cycle makeup pretreatment system shown in Figure 2.5.12.1 is production of filtered water for domestic uses, the cycle makeup demineralizer, and plant service water systems. Storage, a part of this system, accommodates variations in the rate of production and use of water. The system is designed to produce 120 gal/min partially softened, filtered water from raw water taken from the river. The filters, coagulator, and filtered water distribution pumps are in the water treatment building. The system consists of these major components:

- Coagulator (TK-303). The coagulator is a constant-rate water treatment and clarification unit of the sludge-recirculation type. It is a circular steel shell containing a center cone and draft tube, a sludge recirculator, a settling zone, and a sludge scraper.

- Dry Chemical Feeders (BN-305 and.306). There are two dry chemical feeders – one for coagulation and one for pH adjustment. The dry chemical feeder feed rate is manually adjustable and constant when raw water is flowing to the coagulator.

- Hypochlorite Solution Feeder (TK-302). The unit consists of a PVC-lined steel hypochlorite reservoir tank equipped with a motor-driven agitator and two 100% capacity, positive-displacement, diaphragm-type pumps. The hypochlorite solution feed rate is manually adjusted to be proportional to the raw water flowing to the coagulator.

- Gravity Filters (F-302A, B and C). Three steel, single-compartment, gravity filters, coated with coal-tar epoxy, are rated at 2 gal/min-ft^2. One unit is a spare. Each filter compartment is sealed on the influent side; each contains 30 in. of sand and anthracite. The underdrain for each compartment consists of stainless steel strainers in a carbon steel flat-bottom plate. The inlet and backwash outlet piping is connected to the sealed filter influent compartment. The backwash water storage zone above the filter compartment is connected to the underdrain collection chamber by a riser pipe.

- Filtered-Water Transfer Pumps (P-306A, B and C). The filtered water transfer pumps are electric-motor-driven, vertical, turbine-type pumps that transfer water from the filtered water wetwell to the external storage tank. There are three 50 percent capacity pumps, including one spare. Normally, no more than two pumps operate simultaneously, and then only when high makeup is necessary.

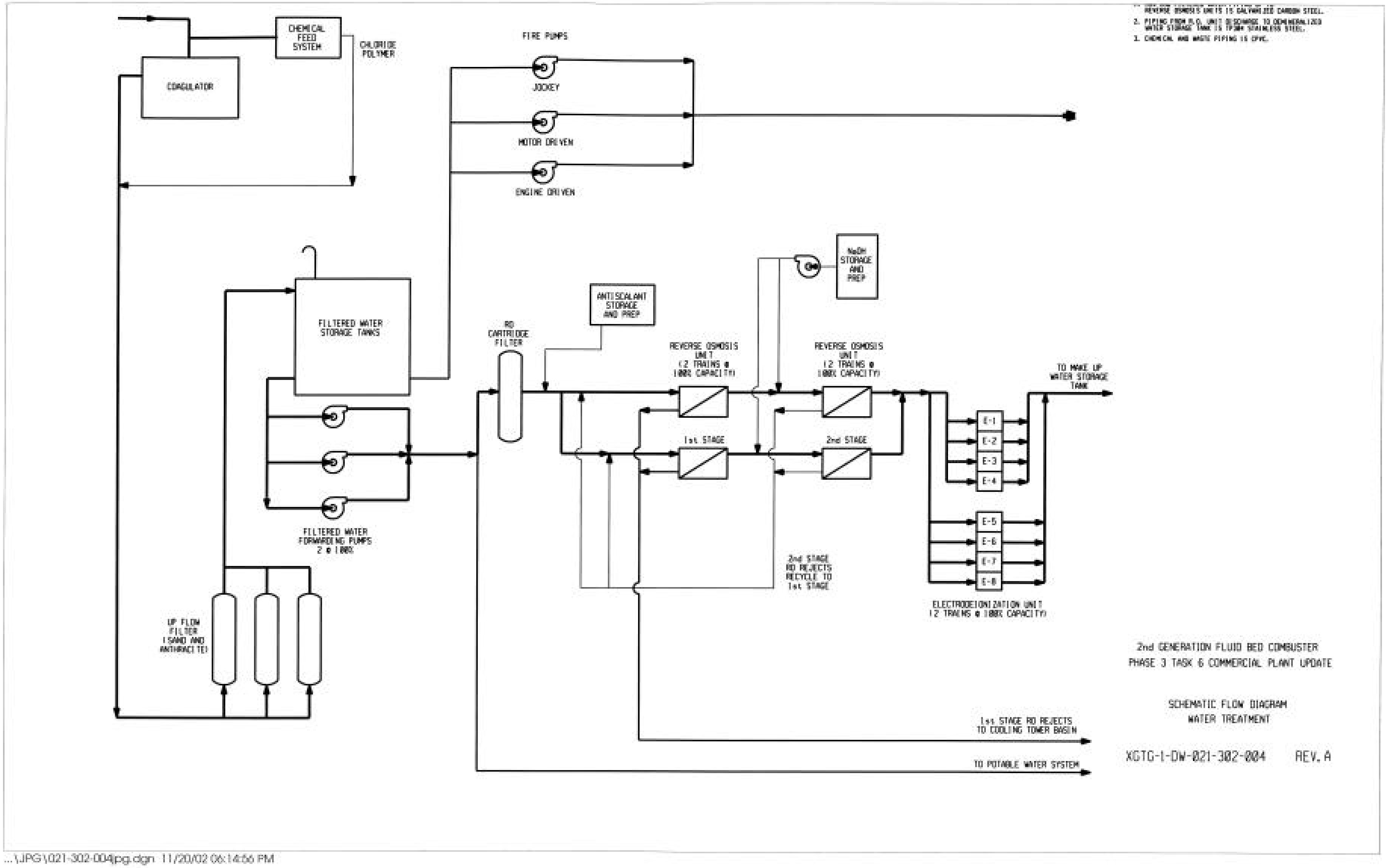

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Figure 2.5.12.1 Plant Makeup, Pretreatment, and Demineralizer Makeup

- Filtered-Water Storage Tank (TK-304). The filtered water storage tank is a field-erected, vertical, cylindrical, lined carbon steel tank with a conical roof. The tank is on grade near the water treatment building. A caged ladder gives access to the tank roof. A vent at the center of the roof is designed to prevent entry of birds, insects, and air-borne debris.

- Filtered-Water Forwarding Pumps (P-307A, B and C). The three filtered-water distribution pumps are electric-motor-driven, horizontal, centrifugal pumps, each 50 percent capacity, that distribute water from the storage tank to the various filtered water uses in the plant.

2.5.13 Demineralized Makeup Water System

System Function. The demineralized water system shown in Figure 2.5.12.1 provides a makeup supply of acceptable-quality demineralized water to the feedwater system. The demineralizer system is supplied by filtered water from the filtered-water storage tank. The demineralized water system removes dissolved solids from the inlet water via ion exchange, utilizing reverse osmosis and electrodeionization processes.

System Description. The Demineralized Makeup Water System is comprised of reverse osmosis units (RO) and electrodeionization (EDI) units in series. The system includes a cartridge pre-filter to remove any suspended solid that may have entered the system after the clarificatin process described in the previous subsection. The RO and EDI systems are in series; each is comprised of two 100% capacity trains. The RO process is arranged in two stages in series. First stage reject is sent to the cooling tower as part of the makeup water required by the tower, while second stage RO unit reject is recycled to the first stage inlet. The EDI unit acts a polisher for the second stage RO unit product, and is routed to the demineralized water storage tank. All system wetted surfaces (piping, valves, pumps, and the demin water storage tank) downstream of the first stage RO unit is made of stainless steel.

Equipment Description

Reverse Osmosis (RO) Units:

- Two 100 percent reverse osmosis (RO) units are furnished in FRP pressure vessels in an array configuration. Membrane elements, seals, connectors, and end caps are provided. All interconnecting feed, product, and reject piping is shop assembled. Valves and instrumentation are provided for proper operation and in-place cleaning of the elements.

- The RO system includes all controls and instrumentation, piping, valves, and accessories for a fully functional, fully automatic system.

- The RO system provides at least 75 percent recovery and removes at least 99 percent of the influent total dissolved solids. The Langelier Saturation Index will not exceed 1.5 in the reject water with the addition of the antiscalant.

- Two 100 percent capacity RO booster pumps are furnished complete with accessories and drive motors to increase the water pressure as required for proper system performance. The pumps are designed with a head capacity characteristic which rises steadily from the design capacity to shutoff, and are selected to allow proper filtration by the RO membranes while operating at any point along the pump characteristic curve above the minimum flow rate for the pump. All pump wetted parts are 316 stainless steel.

- The RO clean-in-place skid includes a skid mounted solution tank, centrifugal pump and motor, 5 micron solution filter, solution mixer, immersion heater, valves, piping, instruments, and any other required accessories. Hoses are provided as required for connection of the cleaning skid feed and recirculation lines to the RO units.

Decarbonator:

- One 100 percent capacity decarbonator is provided at the discharge of the RO unit. The decarbonator is equipped with an integral storage tank, one 100% capacity forced draft blower, and two 100 percent capacity decarbonator transfer pumps.

- The decarbonator is sized for a hydraulic rate not to exceed 25 gpm/ft2. The decarbonator is designed to decrease carbon dioxide (CO_2) levels in the product to less than 5 mg/l.

- Decarbonator packing is of a corrosion-resistant material such as polypropylene.

- The unit is equipped with a clearwell tank having 3 minutes storage from high to low operating level and is of FRP construction with UV inhibitor designed in accordance with ASTM-D3299.

- The decarbonator includes all controls and instrumentation, piping, valves, and accessories for a fully functional, fully automatic system.

Electrodeionization System (EDI) Units:

- Two 50 percent capacity skid mounted electrodeionization units are provided for final demineralization of the cycle makeup water. The EDI system includes all controls and instrumentation, piping, valves, and accessories for a fully functional and automatic system.

- The EDI system is designed to provide at least 95 percent recovery. EDI product water will meet the boiler and turbine manufacturers' water quality guidelines, turbine supplier requirements, and the ASME boiler chemistry guidelines for makeup water for boiler drums operating above 1500 psig.

- A stainless steel concentrate pump is provided, to recirculate the concentrate water through the EDI stacks.

- The power to the skid is supplied as AC current. Any required AC/DC converter is supplied by the EDI vendor.

Chemical Feed Equipment:

- A sodium bisulfite feed system is provided to meter commercial-strength ("neat") sodium bisulfite into the system piping upstream of the cartridge filter to protect the RO membranes from chlorine damage.
- An antiscalant feed system is provided to meter commercial-strength ("neat") antiscalant into the system piping upstream of the cartridge filter to protect the RO membranes against scaling.
- A sulfuric acid feed system is provided to meter 66 degree Baume sulfuric acid into the system piping upstream of the cartridge filter to control the system feed water pH and improve carbon dioxide removal in the decarbonator.
- Antiscalant and sodium bisulfite is supplied in refillable totes. The sulfuric acid chemical feed skid is equipped with a day tank sized to contain at least one (1) day's supply of the sulfuric acid required for operation of the cycle makeup treatment system. The day tank is refilled via a transfer pump from the bulk sulfuric acid storage tank located at the cooling tower.
- Each chemical feed system is a complete, prefabricated unit, including one 100 percent capacity diaphragm type chemical metering pump.
- A static mixer is installed in the line downstream of the chemical injection points to ensure adequate mixing. Injection quills for the chemical feeds are provided in the piping.
- The chemical feed systems include all controls and instrumentation, piping, valves, and accessories for a fully functional, fully automatic system.

2.5.14 Compressed Air Systems

Compressed air system requirements, depicted in Table 2.5.14.1, are based on the baseline heat and mass balance (Figure 2.2.0.1).

System Functions. Compressed air is used primarily in the carbonizer and PCFB boiler to fluidize their beds and support coal gasification and combustion reactions. These requirements and others are shown in Table 2.5.14.1. Except for "shop air" and "instrument air," the gas turbine compressor supplies the entire plant with compressed air at 279 psia and 811EF. After cooling to 557EF, this air is passed through a boost compressor that increases the air pressure by 40 psi to compensate for pressure drops induced by carbonizer and PCFB components. Two smaller air flows are further boosted in pressure to pressurize lock hoppers and pneumatically transport/feed the coal and dolomite.

Design Criteria.

- The design criteria for the booster compressors are set by the process pressure needs listed in Table 2.5.14.1. Sizing is based on using a full-sized compressor and, with the exception of the main/process air boost, a spare full-sized unit with appropriate valving.
- The instrument air is typical: 40 psig with a -40°F pressure dewpoint. Shop air is also standard at 100 psig. Neither use is shown in the overall heat and mass balance.
- A small amount of service air is needed at the highest pressure (354 psia) for purging and miscellaneous uses.
- Feed system transport air requirements are based on vendor information.
- The ceramic filter booster compressor sizes and pressures were determined by Siemens Westinghouse.

Table 2.5.14.1 Major Compressed Air Requirements

	Flow, lb/h	Pressure, psia	Temp., EF
Feed System Pressurization Air	2,750	750	150
Feed System Transport Air	103,482	354.4	134
Carbonizer	403,568	304.4	599
PCFB Boiler	1,683,957	309.8	599
PCFB Bottom Ash Transport	19,600	309.8	599
Shop Air and Instrument Air	3,720	115	180

System Description. The gas-side pressure drop through the fluid beds, cyclones, candle filters, and piping of the baseline plant is greater than the corresponding pressure drop through the combustor of a simple gas turbine fueled by natural gas. Increased pressure drop between the main compressor and the expander in PCFB plants can result in reduced expansion through (and less power from) the gas turbine, unless compensated for in some manner.

The reduced pressure at the expander first stage nozzles affects operation of the gas turbine in the following manner: first, the reduced pressure reduces the flow capacity of the expander nozzles, and thereby of the entire machine. This occurs as a consequence of the fixed value of the choked flow parameter at the nozzle entrance, which defines a relationship between flow, the square root of the turbine nozzle entrance temperature, the flow area, and the pressure. Reduced mass flow through the expander nozzles results in reduced mass flow through the machine, thereby reducing power output. Second, in addition to the reduction in flow capacity of the expander, the reduction in pressure at the expander entrance also reduces the expansion pressure ratio that is achieved. This also reduces the work and power produced by the expander.

To satisfy the fixed flow parameter relationship, one or more of the following must occur:

- Pressure is restored to its original design basis value by means of a boost compressor or by adding an additional stage to the gas turbine main compressor.

- Turbine inlet temperature is reduced (along with firing temperature).
- Air mass flow through the machine is reduced.
- The nozzle area is increased.

Only the first remedy noted above completely resolves the issue, as it restores the flow capacity of the machine along with the full expansion ratio of the expander. For this conceptual design study, a boost compressor has been added for the air exported to process so it returns at the normal gas turbine rotor inlet pressure yielding only a slight reduction in the overall plant efficiency. Adding a new stage to the gas turbine main compressor requires a significant design and investment effort by the gas turbine vendor, and is beyond the scope of this study.

- Main Boost Compressor

  The main/process air boost compressor is a centrifugal fan type unit placed in a heavy gauge housing with a stuffing box to minimize shaft seal leakage. The fan and housing are fabricated of carbon steel (A-36 for the housing and A-514 for the wheel).

  Variable Speed Boost Compressor Drivers. There are a number of driver options for the boost compressor. The requirements for the driver are as follows:

  - One unit, supplying up to 12,000 horsepower at design speed.
  - Power delivered to the compressor at a design basis shaft speed of 900 rpm at full load.
  - Capable of operating over a speed range of 20 to 100 percent of design speed for sustained periods.
  - If an electric motor is used, be capable of low-torque start to reduce starting amps, increase motor life, and reduce impacts on the electrical supply bus.
  - Have low parasitic load penalty over the speed range to maximize station energy efficiency.
  - Have low operational maintenance levels, and maintenance characteristics that do not normally require shutdown during plant operation.
  - Require shutdown maintenance only during the annual plant maintenance outage.
  - This will be a plant startup device. It must be capable of operating the boost compressors independent of plant operation. That is, if electrical, driver needs to be tied to the grid bus; if steam, it must be supplied with steam from the station auxiliary steam header.

  Three types of large horsepower driver systems were considered, as follows:

  - Solid state electronic system generating variable frequency power to a synchronous or induction type electric motor. The full-load motor speed is set at 3550 rpm, and a fixed ratio gearbox with a 4:1 speed reduction is incorporated to match the full load speed requirement of the driven equipment.

- Fixed speed electric motor driver (3550 or 1750 rpm) with variable speed hydro-viscous or hydraulic drive and a fixed ratio gearbox.
- Steam turbine driver and speed reducing gearbox. The gearbox is required since the steam turbine selection (for a machine of this power rating) is likely to be at shaft speeds in the range of 5000 to 6000 rpm (for best efficiency), while the fan shaft is likely to about 900 rpm at full load (based on the hydraulic condition that yields the best fan efficiency).

The selection of driver for the boost compressor system requires a detailed project specific assessment. Selection involves trades in performance, operations, and economics. For the purposes of this study, an electric motor drive with gearbox and electronic variable speed control was selected; and because of the unit size and cost, only one was provided.

- Lock Hopper and Feed System Air Booster Compressors. Air for the lock hopper feed system is first cooled in a two-stage air heater/shell-and-tube heat exchanger system and then dewatered in a separator before being boosted in pressure. One compressor boosts the air pressure by approximately 50 psi for the pneumatic transport of feed material while a second compressor boosts a much smaller air flow by approximately 450 psi for rapid pressurization of the lock hoppers. Reciprocating compressors were selected for these applications.

  Two transport air coolers are located upstream of the compressor – an air-cooled heat exchanger (9 ft wide x 16 ft long) and a water-cooled shell-and-tube exchanger (35-in. diam x 20 ft long). The temperature range is split between air-cooled and water-cooled exchangers to avoid depositing dissolved solids on the tubes because of the hot (712EF) inlet temperature (i.e., the tubewall temperature could reach a point where the cooling water would vaporize on contact). The water-cooled unit serves as a low-temperature economizer, heating about 30 percent of the condensate. This condensate stream is further heated in ash stripper coolers and screw coolers before being routed to the deaerator.

- Auxiliary Air Compressor. The auxiliary air compressor supplies 100 psig air for instruments and for miscellaneous intermittent shop uses. Only one compressor is furnished as back-up is provided by a tie-in to the turbocompressor air line. The reciprocating air compressor chosen is rated for 625 acfm at 125 BHP. Ambient air is used for the inlet.

  An aftercooler, a cyclone water separator, and a 100-ft^3 air receiver follow the compressor. The instrument air system has a typical fixed-cycle air dryer (alumina) and cartridge filters.

- Carbonizer Filter Blowback Compressor. This compressor receives clean, cool, recycle syngas at 286 psia and boosts the pressure to 900 psia for pulse cleaning the ceramic candle filter. The compressor is of a reciprocating type that can deliver syngas at up to 1360 lb/hr at pressures as high as 1200 psia; one full-sized spare is provided.

- PCFB Filter Blowback Compressor. This compressor receives 298 psia air from the solids feed air system and boosts the pressure to 900 psia. The compressor selected is a reciprocating type that can deliver air at up to 4910 lb/hr at pressures as high as 1200 psia; one full-sized spare is provided.

2.5.15 Ash-Handling System

The ash-/spent sorbent-handling system required for the baseline plant is shown in Figure 2.5.15.1.

System Functions. The overall function of the ash handling system is to receive and convey 500EF ash from the PCFB ash bin to storage silos; to prepare the silo-stored ash for discharge; and to feed it to disposal trucks.

Design Criteria. As the plant mass balance diagram (Figure 2.2.0.2) shows, the total ash flow from the plant is 98,369 lb/h with as received coal and dolomite feed rates of 272,406 and 78,864 lb/h respectively at 100 percent load. The ash flow splits as a 25 percent bottom ash-75 percent fly ash mixture generated by the PCFB boiler.

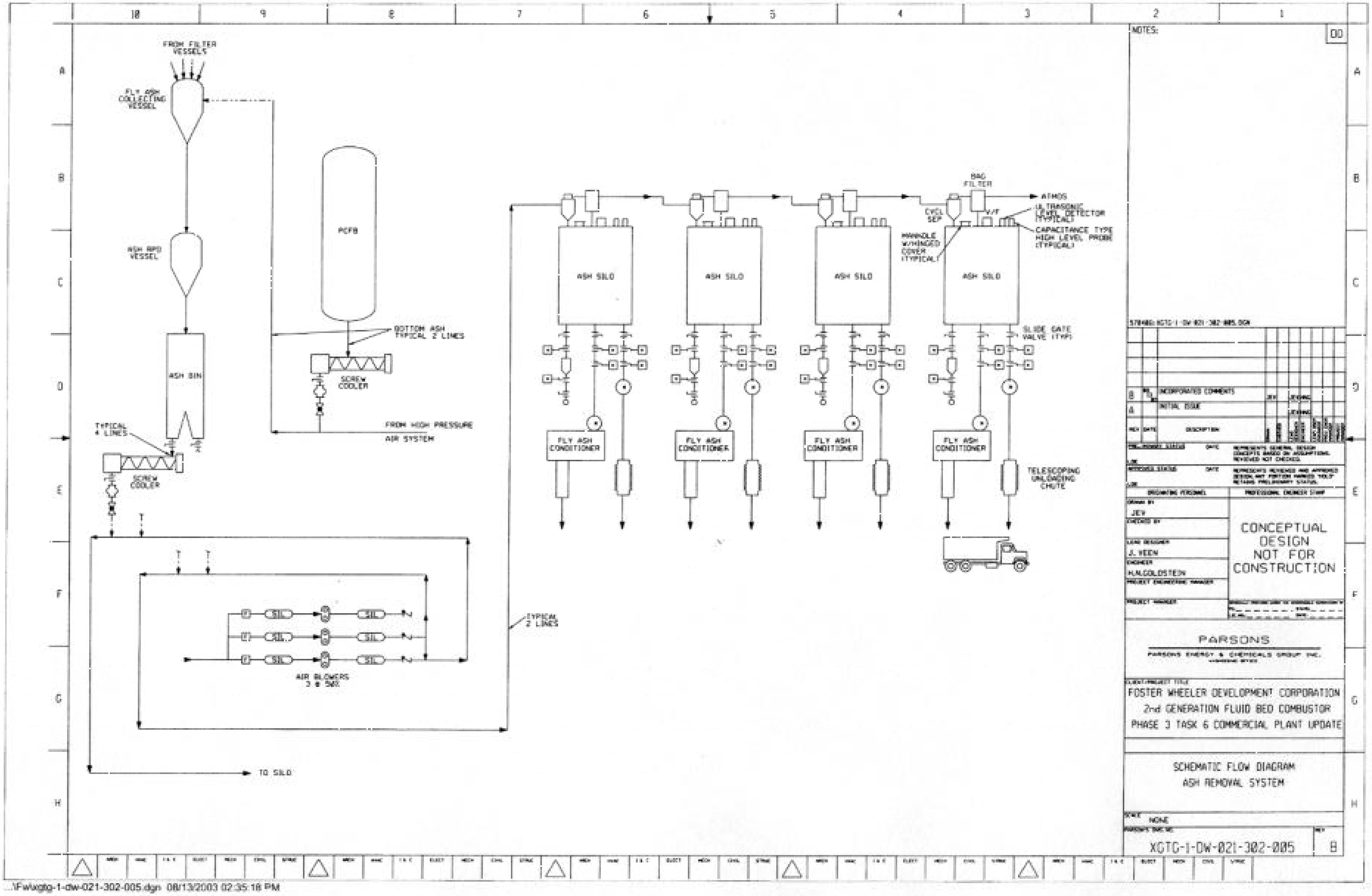

Figure 2.5.15.1 Ash Removal System

System Description.

- The ash handling system conveys ash pneumatically from the discharge of the screw coolers located under the PCFB filter ash bin to the ash silos. The silos provide storage for a three-day period and the transfer is accomplished by compressed air provided by a complement of blowers, supplying air at 15 psig to the conveying system. At the ash silo, the ash enters a cyclone, which separates the ash from the conveying air. The cyclone overheads are ducted to a bag filter to remove fine particulate, and the transport air is then discharged to atmosphere. The ash material from the cyclone and bag filter drops into the silo. The ash is stored in the ash silos until discharged to a truck for off-site removal on a periodic basis. An ash pugmill is provided at the outlet of each silo to mix the ash with water and suppress dusting during unloading.

Major Equipment Description.

- Ash Storage Silos. Four ash silos designed for a combined capacity of 3600 tons, provide for a nominal 3 days of storage at the baseline 100 percent load ash flow rate of 49 t/h. The inlets are sized to accommodate a maximum conveying capacity of 85 t/h. The outlet of each silo discharges through an ash pug mill and can fill three 20-ton trucks every hour yielding a maximum discharge rate of 240 t/h.

  Ash Storage Silos

Quantity/Type:	Four elevated concrete cylindrical silos, one cone bottom each with fluidizing outlet blower and nozzles.
Capacity:	900 tons each
Inlets:	One each silo via cyclone separator and bag filter)
Outlets:	One vertical gravity drop via isolation valve to ash pelletizer at 60 t/h.

- Ash Pugmills. Each of four pugmills provides an ash removal rate 1.25 times the maximum ash generation rate. With two pugmills running, the ash removal rate is more than double the maximum generation rate. If all four silos were to be full, with two pugmills in operation they can be emptied in 52 hours with the plant running at full load.

  Ash Pugmills

Quantity:	Four
Capacity:	Nominal 60 t/h each
Drivers:	Two 25-hp ac motors

- Ash Conveying Blowers. Three blowers are provided at 50% capacity each to supply compressed air at 15 psig to the ash conveying system. Each blower is rated at 1000 acfm, and is driven by a 100 hp 460 volt 3 phase electric motor.

- Ash Fluidizing Blowers. Three blowers are provided at 50 percent capacity each to supply compressed air at 15 psig to fluidizing nozzles in each ash silo. The air fluidizes the ash so that it flows freely to the silo outlet nozzles. Each blower is rated at 250 acfm, and is driven by a 25 hp 460 volt 3 phase motor.

- Other equipment comprising the ash handling system includes numerous slide gate valves, controls, and instrumentation. Ash conveying piping is provided with special fittings at elbows to withstand abrasion and wear from the ash.

2.5.16 Plant Electrical Equipment

Plant power generation is delivered by one combustion turbine generator and one steam turbine/generator. The electrical scope includes the in-plant auxiliary loads and associated distribution system up to the high-voltage side of the two generator step-up transformers and two plant auxiliary transformers.

The utilization voltages are 13.8 kV, 4160 V, 480 V, 480/277 V, and 208/120 V. The generation voltages are 22 kV for the combustion turbine unit and for the steam turbine unit. Each generator supplies power through an isophase bus duct and dedicated step-up transformer to an overhead connection to a high-voltage transmission line.

Each of the two auxiliary power transformers receives power from a high-voltage transmission line and is connected to 13.8-kV switch gear by a segregated bus duct. The 13.8-kV switch gear feeds the large motors, miscellaneous plant feeders, and 4160-V switch gear. The 4160-V switch gear feeds associated motors and a 480-V switch gear which, in turn, feeds 460-V motors, feeders, and motor control centers.

Aerial, triplexed cable runs throughout the plant area on wood pole lines to furnish 13.8-kV power to remote electrical loads.

A 460-V unit-essential motor control center receives normal power from a 480-V substation and emergency power from an alternative diesel/generator source. The unit-essential motor control center feeds a battery, battery charger, redundant charger, and dc panel. A dc supply from the panel feeds an ac inverter for an uninterruptible power supply to computer and critical power supplies, with an alternative feed directly from the unit-essential motor control center through a regulating transformer.

The combustion turbine/generator units are supplied as packages, which include: starting package, electrical/control package, isolated-phase bus, surge equipment and potential transformers in a cubicle, and fire protection. Equipment basic-impulse levels will be sized to suit the site conditions.

Generators.

- Combustion Turbine/Generator. The combustion turbine drives a 22-kV, three- phase, 60-Hz generator rated at 300 MVa at 0.9 power factor. It is hydrogen cooled with shaft-mounted axial blowers for circulating cooled hydrogen through the generator. The generator is complete with turning gear, seal system, lube- oil system, and starting system, which includes a 13.8-kV starting motor and clutch. The exciter is a potential source, static unit with thyristor control.

- Steam Turbine/Generator. The steam turbine drives a 3600 rev/min, standard continuous rating, 22 kV, three-phase, 60-Hz generator rated at 310 MVa, 0.9 power factor at 60-psig hydrogen pressure, hydrogen inner-cooled. The generator is complete with turning gear, seal system, and lube-oil system. The exciter is a potential source, static unit with thyristor control.

Generator Step-Up Transformer. The main step-up transformers are three-phase, 60 Hz, 55°C/65°C rise, forced-oil and -air rating, cooled, sized to carry the maximum generator output (minus the parasitic demand loads) at rated power factor and 95 percent rated voltage with a 30°C average ambient. The limiting generating factor is the turbine. The transformer impedance is standard for the MVa rating and consistent with voltage regulation and short-circuit current considerations. The transformer has delta-connected low-voltage and solid-grounding wye high-voltage windings. It is equipped with two 2½ percent, no-load, full-capacity taps on the high-voltage windings and high-voltage metal oxide surge arresters. Current transformers within the proper accuracy classes provide both relay protection and incoming/outgoing metering.

Station Service Transformers. The station service transformers are three-phase, 60-Hz, 65°C rise, forced-air self-cooled forced-oil and -air rating, cooled, and sized to carry the maximum demand load on 80 percent self-cooled rating at rated power factor and 95 percent rated voltage with a 30°C average ambient. The transformer impedance is standard for the MVa rating and consistent with voltage regulation and short-circuit current considerations. The transformer has delta-connected high-voltage and wye-connected low-voltage windings brought out for a low-resistance grounding system. It is equipped with two 2½ percent, no-load, full-capacity taps. In addition to standard accessories, the transformer has tank-mounted secondary resisters (10-second rated) enclosed in metal grills for grounding the neutral of each low-voltage winding. Bushing current transformers with the proper accuracy class satisfy metering and relaying requirements.

Auxiliary Transformers. The auxiliary medium- or low-voltage power transformers are three-phase, 60 Hz, 65°C rise (dry- or cast-resin type for indoor or oil-immersed for outdoor). They have one stage of fan cooling and are sized to carry the maximum demand load on 80 percent of the self-cooled or dry transformer self-cooled rating at rated power factor and 95 percent rated voltage with a 30°C average ambient. The transformer impedance is standard for the MVa rating and consistent with voltage regulation and short-circuit current considerations.

Bus Duct. An isolated-phase bus connects the generator line terminals to the main step-up transformer. The bus duct section between the generator and main step-up transformer is rated to carry rated generator MVa continuously at 95% of rated generator voltage without exceeding a 65°C conductor temperature rise for a maximum 40°C ambient temperature.

A segregated-phase bus connects the station service transformer to the 13.8-kV switch gear. The segregated-phase bus is rated to carry the maximum transformer current continuously at 95 percent of rated voltage without exceeding a 65°C conductor temperature rise for a maximum 40°C ambient temperature.

Protective Relaying. Protective relays in the electrical system permit isolation of faulted or overloaded equipment and cables as quickly as possible to minimize equipment damage and limit the extent of system outages. The generators, step-up transformers, and station-service transformers have primary and backup relaying.

Medium-Voltage Switchgear. The medium-voltage switch gear consists of 13.8- and 4.16-kV metal-clad, NEMA I[*] assemblies feeding large motors, power transformers, and 480-V load centers. Each switch gear line-up includes provisions for future additions on one end. The switch gear assembly incorporates drawout circuit breakers equipped with current transformers, protective and auxiliary relays, ammeters, indicating lights, cable terminations, and other special required devices.

Low-Voltage Unit Substations. The 480-V unit substations have double-ended switch gear with integral transformers at each end and a normally open tie breaker separating the two switch gear buses. The transformer associated with each power center is the dry-type, three-phase, fan-cooled rated, dry transformer OA/AA (self-cooled/forced-air) rating, connected delta on the high-voltage winding and solidly grounded wye on the low-voltage winding. The transformers are sized for the running load plus 20 percent margin based on the forced-air rating. Standard transformer impedances are used. The switch gear is 600-V class in a NEMA-I metal enclosure with drawout components. Motors rated 101 through 200 hp are, as is normal, supplied directly from load-center breakers. A three-phase dry-type transformer with disconnect and a 120/208-V circuit breaker are provided where required.

Motor Control Centers. Motor-control centers are located throughout the plant in areas of concentrated loads. They are 460 V, in NEMA enclosures to suit the environment, made of standard modules, 20 in. deep. All devices are front-mounted, except those made of valve-reversing starters, which can have rear-mounted components.

Essential Power System. The essential power system provides power to essential auxiliaries required for shutdown in the event of a total blackout of a unit or the complete plant. System components are:

- Emergency generator
- Essential motor control center
- 480-V ac essential-power panel

A diesel-engine-driven emergency generator supplies shutdown power to the essential motor control center. Major loads supplied from the essential motor control center are:

- Turbine auxiliary lube-oil pump and turning gear
- Essential lighting
- Boiler feed pump turbine oil
- Selected sump pumps
- Battery chargers

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[*] National Electrical Manufacturers Association

pump and turning gear

The essential motor control center is supplied through an automatic transfer switch from either a 480-V power center or the emergency generator. Loss of voltage at the transfer switch starts the emergency generator; when rated voltage and frequency are achieved, the switch transfers the essential motor control center to the generator.

Uninterruptible Power Supply System. The uninterruptible power supply system furnishes a reliable source of 120-V ac power and control voltage to equipment vital for plant operation and shutdown. The system consists of:

- An inverter
- A static switch
- A manual bypass switch
- A 120-V ac vital-ac distribution panel.

The inverter takes normal power from the 125-V dc power system. The inverter output is connected to a static switch; upon failure of the inverter, the switch automatically transfers it to an alternative 120-V ac supply.

The uninterruptible power supply is sized to feed the following plus 20 percent margin:

- Combustion controls and burner management
- Turbine generator/ electrohydraulic control system.
- Turbine supervisory instruments
- Recorders and indicators
- Other essential instrumentation
- Critical components of plant control systems

Direct Current Power System. A 125-V dc system furnishes control power to the switch gear and for power feeds to the uninterruptible power supply, emergency lighting, and motors such as those that drive the emergency bearing and seal-oil pumps. The system consists of a battery, two battery chargers, and dc distribution panels. Battery capacity provides emergency lighting and control power for orderly plant shutdown, enables uninterrupted operation of vital equipment via the uninterruptible power supply system, and enables breaker operation to set up a plant restart.

Motors. Except for special applications, all ac motors are squirrel-cage induction-type with Class B insulation, are designed for full-voltage starting, and have the lowest possible locked-rotor current consistent with good performance and design. The motors match the inertia and speed-torque requirements of the driven equipment. Where required, medium-voltage motors are designed to start and accelerate the connected load with an applied voltage of 80% of rated voltage.

Motor voltage ratings and power supply source are shown in Table 2.5.16.1.

Motor enclosures are normally fully guarded, open, drip-proof for indoor service and weather-protected NEMA Type II for outdoor service. Motors 200 hp and lower are totally enclosed, fan-cooled (TEFC) for outdoor service. Regardless of size, all motors subject to fire protection spray water are totally enclosed, fan cooled unless limited by size to a totally enclosed, non-cooled (TENC) enclosure. Explosion-proof motors are provided where required for service in hazardous locations.

Table 2.5.16.1 Motor Voltage Rating and Power Supply Service

Horsepower	Voltage	Phase	Supply Source
1500 and up	13,200	3	3.8-kV switch gear
250 to 1000	4160	3	4.16-kV switch gear
125 to 200	460	3	480-V switch gear
1/2 to 100	460	3	480-V motor control center or individual starter
Less than 1/2*	115	1	Lighting cabinets or 120-V distribution panels

**Fractional hp motors less than 1/2 hp used for reversing service, such as motors on valve operators, are 3-phase, 460-V starter.*

Totally enclosed and explosion-proof motors have a 1.00 service factor. Drip-proof and weather-protected motors have a 1.15 service factor, except where an adequate margin is already available. The service factor is not infringed upon by normal continuous loads.

All medium-voltage motors include resistance temperature devices for overload detection, and motors over 1500 hp have six leads and three donut-type current transformers mounted in the terminal box for self-balanced primary-current differential protection. All medium-voltage motors and valve motor operators have space heaters, and all outdoor motors above 50 hp have space heaters that automatically activate when the motor is idle.

Grounding/Lightning/Cathodic Protection. The grounding system is a permanent and continuous system designed to provide safety to personnel, protection to equipment, and a minimum input of electrical noise to control and instrumentation signals.

The plant grounding grid is made of buried copper grounding loops around each building, a buried grounding grid in the switchyard for step-and-touch potential protection, and buried grounding grids for step-and-touch potential on both sides of fences and gates where applicable. The grounding grid is designed for a resistance to ground of less than 1 ohm. All grids and loops are connected at two places (minimum).

All building, structural, and outdoor tank steel is connected by copper cable to the main plant ground grid. Electrical continuity is maintained for all structural steel used as a grounding path. All medium-voltage equipment is connected to the plant grounding grid by copper cable. Small miscellaneous equipment lower than 600 V, in remote locations, may be grounded to the building steel and conduit system, providing electrical continuity to ground is maintained. Electronic devices have isolated signal grounds, chassis and enclosure grounds, and electrical power-source grounds for safety and to minimize electrical noise inputs to the controllers from external sources. Instrument cable shields are grounded at one end only to prevent circulating currents, unless otherwise recommended by the instrument manufacturer.

Metal-oxide-type station lightning arresters on the high-voltage side of the main step-up transformers and station service transformers protect insulation from voltage surges. The chimney cooling tower and tall buildings are protected by air terminals in accordance with the Lightning Protection Code NFPA No.78.

Underground structural steel, pipes, tanks, and wharf areas are protected from harmful galvanic corrosion by cathodic protection. The cathodic protection system is designed in accordance with guidelines established by the National Association of Corrosion Engineers (NACE). The cathodic protection consists of individual galvanic sacrificial anodes or an impressed-current system, as determined by field test and design.

Heat Tracing. Where required, freeze protection is provided for all outdoor piping, gauges, and instrumentation with self-regulated parallel-type heat cable. Space heaters are utilized for items that are not suitable "for heating cable application. Heating cable circuits are supplied from distribution panels similar to those used for lighting circuits and are controlled by thermostats.

Lighting. Normal, emergency, and egress lighting is provided for the station, service building, remote buildings, and associated outdoor areas within the plant boundary.

Normal lighting is energized from three-phase four-wire lighting panels throughout the station. Each lighting panel is fed from locally mounted 480-/277-V panels or 480-208Y/120-V transformers that are fed from the nearest motor control center. Yard and roadway lighting is supplied at 277 V from the nearest motor control center or power distribution cabinet.

Lighting illumination levels are calculated in accordance with recommended levels of illumination in an electric supply station, as listed in Part 1, Section 11, of the latest edition of the National Electrical Safety Code.

Emergency dc lighting in the station building and in the control room permits safe egress. For outlying miscellaneous buildings, emergency lighting is from self-contained battery-charged lamp units. Office areas, shops, laboratories, and the control and computer rooms have fluorescent fixtures. High-intensity discharge fixtures are installed in indoor plant areas. Incandescent fixtures are used for the emergency lighting system and for exit lights. Fixtures are explosion-proof in hazardous areas of the coal-handling system.

Wire for lighting systems is Type RHW (moisture and heat-resistant rubber cable), run in either conduit or tray. All fluorescent and pendant lighting fixtures have Type SO high-temperature flexible cord for wiring from the outlet box to the fixture. Conduit used for lighting systems can be rigid, IMC (intermediate conduit}, EMT (intermediate conduit}, or a combination of these, depending on the application.

Communication System. An intraplant communication system consists of one paging and five party lines. The speech input to the paging amplifiers is from handsets throughout the plant area and in the control room. Each handset has its own solid-state amplifier. Where required, noise-canceling microphones, speaker-muting controls, and appropriate enclosures are provided. Public telephone lines are installed for administrative areas and the main control room. All communication system interconnecting wiring is installed in conduit.

Miscellaneous Small Power Systems. Miscellaneous, small power systems provide the plant with electrical supply for convenience outlets, food preparation, storage equipment, office and building services, and similar requirements. The systems are.208Y/120-V, three-phase, four-wire supply. They consist of step-down transformers (fed from the plant low-voltage distribution), panel boards, and branch circuit wiring feeding various loads. There are 48-V welding outlets throughout the plant.

2.5.17 Plant Instrumentation and Control

General

The plant control system hardware is described in this subsection, whereas, the plant operating/ control philosophy, e.g., start-up, shutdown, trip, and normal operation are described in Section 2.7. Development of the control system software required by the plant is beyond the scope of this conceptual study and would be performed during the plant detailed design and construction effort.

The control system provided for the PFB baseline plant will be a state-of-the-art, micro-processor-based distributed control system (DCS) located in a central control room. This room will contain the DCS operator consoles, printers, engineering workstation, and other auxiliary equipment. The central control room will be continuously manned.

Design Basis

The control system design, equipment supply, and construction will adhere to applicable American standards, ordinances, and recommendations for fossil power plants.

System Description

The DCS will be used to control and protect the main plant equipment/systems and will serve as the central interface for the operators. This system will be connected to the various instrumentation and control devices throughout the plant, and will be linked to the gas turbine and steam turbine controls through communication data links. All trip signals or other critical I/O between the DCS and the gas and steam turbine-generators will be hardwired. Figure 2.5.17.1 shows a simple schematic diagram of the architecture of the proposed DCS system.

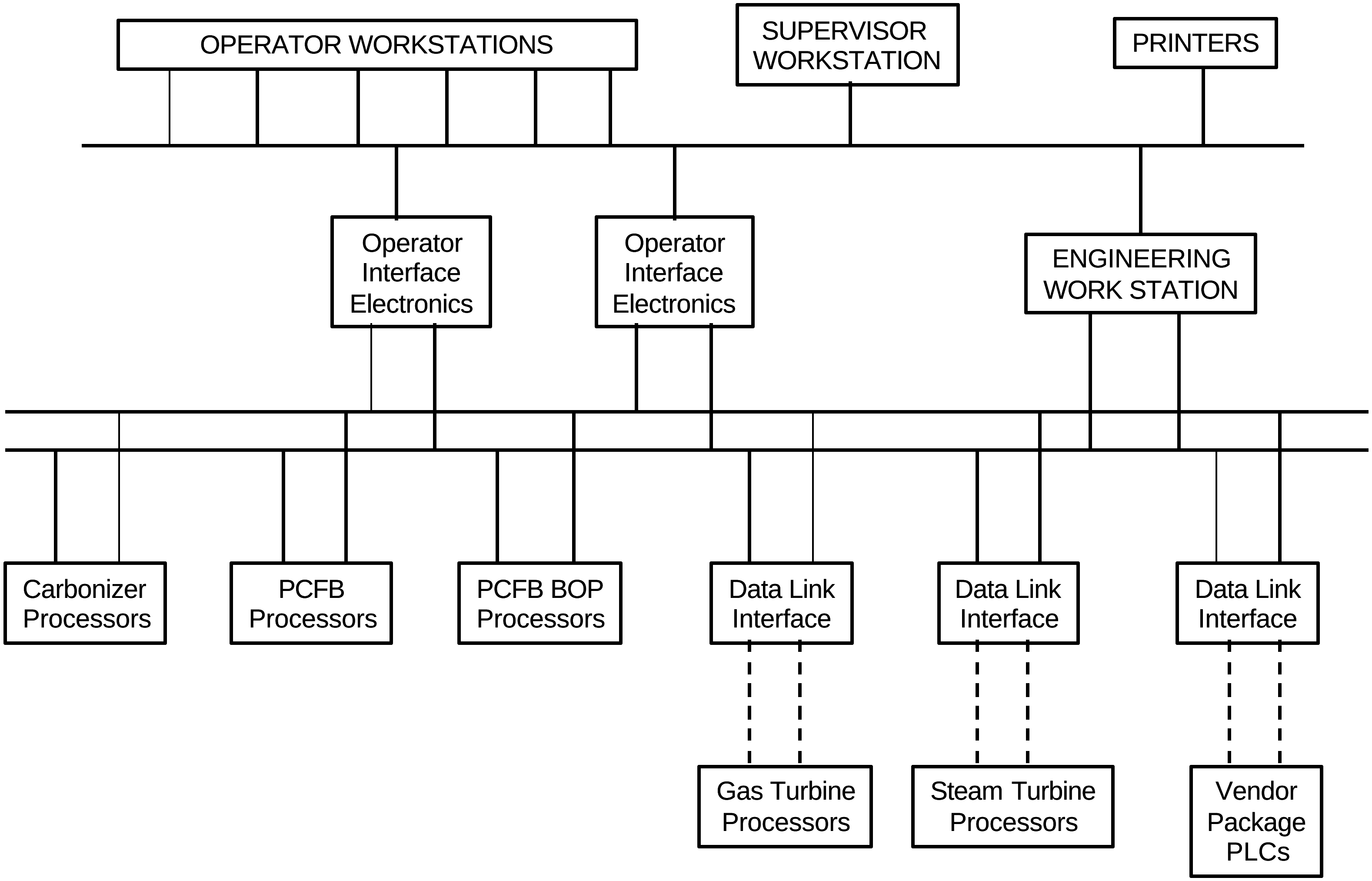

Figure 2.5.17.1 PFB Baseline Plant DCS Network

The DCS will be a hierarchical, microprocessor-based control system. The hierarchical division of the system will enable control at various levels and function groups. All DCS control and monitoring functions will be implemented into functional processors. All processors will be a minimum of 32-bit, multi-speed standard software design, with self-checking features to allow detection of processor malfunctions.

The DCS equipment will be designed such that a component failure of system equipment or a DCS power source failure will not disrupt control system functions. Each process control unit and I/O cabinet will provide redundancy of functional processors, power supplies, and data highway interfaces. If the system detects a processor failure, a power supply failure, or a communications failure, the failed equipment will automatically transfer to its backup. In the case of a processor failure, if the backup is unavailable, the processor outputs will fail to their fail-safe position and allow a manual shutdown of the equipment affected. Upon a backup power supply failure, the affected equipment will fail in its de-energized position.

Remote I/O cabinets located in the field and connected by a redundant data highway to the processing units will be utilized when I/O can be grouped together in the field and will result in a cost savings from reduced cable and conduit.

A redundant coaxial or fiber optic cable highway, installed in separate routed steel conduits, will be used as the communication link between the DCS processing units and operator consoles. An uninterruptible power supply with battery back up will provide the power requirements for the DCS, operator consoles, and other critical equipment.

The DCS will have logging and historical storage and retrieval capabilities in order to facilitate long-term monitoring of plant equipment and performance.

A sequence of events system integral to the DCS will be provided with an interrogation time of 1.0 ms or less. Each point will be time-stamped with resolution of 1.0 ms. Event logs will be provided as well as the printed archived data. The gas and steam turbines will each be supplied with an independent sequence of events system. These packages will provide a gas turbine or steam turbine trip contact to the DCS.

The anticipated required system hardware is listed in Table 2.5.17.1.

Control System Operator Interface

The DCS will have CRT-based operator stations that will be the primary interface to the control system. Smart interactive operator consoles, each with a graphic CRT operator interface display, will be provided. At least two operator interface processors independent of any other computing element will be provided, capable of accessing data from and entering operation interface commands onto the data highway.

Table 2.5.17.1 Required System Hardware

Description	Qty
Operator Interface CRTs	6
Operator interface Electronics	2
Supervisors Workstation (Single CRT)	1
Engineer Workstation (Single CRT)	2
Alarm Printer	1
Event Printer (supports 11x17 paper)	1
Supervisor/Engineer Printer (supports 11x17 paper)	2
Color Printer (for graphics)	1
Sequence of Events (SOE)	2
Gateway (Ethernet highway, Owner's computer system)	1
Global Position Satellite System (GPS)*	1

**GPS provided for time synchronization to each microprocessor-based controls system and SOE via IRIG A, IRIG B, or contact output.*

In normal operating mode, each operator workstation with its video display unit will be in charge of operation and control of a part of the plant. In case of one display unit failure, the other units will take over its functions, thus allowing plant operation and safe shutdown.

Standard interactive graphic capabilities will be utilized. System overviews, subsystem control and monitoring, critical alarm windows, alarm summaries, and trend displays are types of graphic displays to be used.

One engineering console containing one graphic CRT operator interface display with laser printer will be provided for programming. One supervisor station with laser printer will be provided for overall supervision. The engineering console will provide all the functions of the operator's console and will directly interact with the DCS software. One historical storage and retrieval console with logging capabilities with one graphic CRT operator interface will be provided. The DCS main processing unit cabinets will be located in the central control room.

Distributed Control System Design Approach

All operator interfaces for power generation and DCS-controlled process equipment will normally be through the CRT keyboard and color graphics. The DCS will provide all alarm annunciations. Hardwired annunciators, indicators, recorders, status lights, and push buttons will not be used. However, hardwired "trip" push buttons will be provided in the control room and at local panels for the gas and steam turbine.

The DCS system will have the capability to control the entire plant from startup to full load. Actual gas and steam turbine control will be exercised by the individual unit control system that provides the ultimate machine protection function.

The DCS will interface with and control and/or monitor local PLC-based control packages for systems such as:

- Hot gas filter pulse cleaning.
- Water treatment.
- Coal, sorbent and ash handling.
- Lock-hopper feed systems.

Other plant equipment including HVAC, and other pre-packaged equipment supplied with its own integral PLC based controls.

Control for systems that do not have pre-packaged control systems will be configured in the DCS. DCS-controlled pumps, fans, compressors, and motor-operated valves would normally be started and stopped from the central control room interactive graphic displays. The DCS interface to medium-voltage motor starters and MCC larger motor starters (sizes 4, 5, and 6) will be through momentary "start" and "trip" digital outputs. The "trip" digital output will be an electrically held, normally closed contact (open to trip the pump) and will include permissive process interlocks. The trip digital output contact will open momentarily on DCS stop. The DCS interface to MCC small pump motor starters (sizes 1, 2, and 3) will be through one maintained "run" digital output. The process interlocks will be provided through the DCS for running the motors from the DCS only. The running status of major pumps and compressors will be generally determined via discharge pressure monitoring in addition to motor starter auxiliary contact. Motor starter auxiliary contact only will be utilized where discharge condition monitoring is inappropriate.

DCS Inputs and Outputs

Digital inputs to the DCS will utilize cards with 24 VDC internal power for wetting contacts. Digital outputs to solenoid valves from the DCS will utilize cards providing the power for energizing the solenoids. Digital outputs to all other sources will utilize cards providing mercury-wetted relays or solid-state relays.

Analog inputs to the DCS will utilize cards providing the power to drive field-connected instruments and to accept field-powered analog inputs. Analog outputs from the DCS will utilize cards providing power to field devices. All analog inputs to the DCS, other than thermocouples and resistance temperature detectors, will be 4 to 20 ma. Process flow, pressure, and level transmitters will be powered from 24 VDC power distribution within the DCS cabinets. All other transmitters will be powered locally. All DCS analog outputs will be 4 to 20 ma DC, powered from the DCS cabinets except for control valves, which may require customization to their actuator.

Generally, the digital inputs for alarming will alarm in the "reset" (contact open/logic 0) condition. Digital inputs required for control and alarming will be analyzed for failure condition so that the plant and equipment safety are not compromised. In most cases, the digital inputs for status indication will provide the status in the "set" (contact closed/logic 1) condition. Digital inputs required for status and alarming will alarm in the reset condition. Digital inputs for open and close status of all motor-operated valves will be provided. For pneumatic and solenoid actuated valves, the open and/or close status inputs from limit switches will be provided where required by code or where the secondary instrumentation on the process would not indicate the open and close status of the valve. All digital outputs to pilot solenoids for pneumatic valves and solenoid actuated valves will be powered from AC power distributed within the DCS cabinets and remote I/O cabinets.

All shields on instrument cables will be kept floating at the transducer and the final control element ends and will be terminated and grounded to the instrument ground in the DCS cabinet. The redundant coaxial/fiber optic cables of the DCS data highway routing will conform to the DCS vendor requirements. As a minimum, above grade, the redundant data highway will be routed through separate galvanized steel conduits when running between different DCS drop clusters or rooms. Below grade, the redundant highway may run in the same dedicated steel conduit.

The routing requirements for the remote I/O redundant serial communication fiber optics cables will conform to the requirements of the DCS vendor. As a minimum, the redundant serial communication cables will be routed through separate galvanized steel conduits when running between DCS cabinets and remote I/O cabinets.

The DCS system grounding will conform to the DCS vendor requirements. The DCS redundant coaxial data highway will be grounded to the cabinet ground inside each DCS cabinet. As a minimum, the data highway will be grounded every 1,500 feet. Conduit carrying the data highway will be grounded every 100 feet. All data highway coaxial cable grounds must be within 1 ohm of true ground, and within 1 ohm of each other. Cable trays will be kept electrically isolated from DCS cabinets for the top entry cables.

A minimum of 20 percent spare I/O will be provided.

2.5.18 Miscellaneous Auxiliary Systems

Included in this section are the following systems:

- No. 2 fuel oil
- Nitrogen supply and distribution
- Auxiliary steam system
- Industrial waste treatment system

No. 2 Fuel Oil System. The No. 2 fuel oil unloading and storage system consists of two 100 percent capacity oil-unloading pumps, an oil-storage tank, and two 100 percent capacity oil-transfer pumps. Oil is received at the site via railroad tank cars or truck. It is pumped from the tank car using the unloading pump(s) and delivered to the 500,000-gal storage tank. Each unloading pump has a capacity of 500 gal/min.

Oil from the storage tank is pumped to the burners, to other uses, or both, using one of the transfer pumps. The oil-storage tank is enclosed in a dike to confine any oil spill in case of an accident.

The fuel oil system also has sufficient storage to replace the carbonizer heating duty to the topping combustor for 3 days in the event the carbonizer is shut down. With regular 3-day fuel oil delivery, the plant is capable of continuous full-load operation with the carbonizer out of service and direct coal feed to the PCFB boiler.

Nitrogen Supply and Distribution. This system provides nitrogen for conveying, blanketing, purging, and other miscellaneous uses, where an inert gas is required for safety or to avoid problems created by moisture.

Nitrogen is stored on site in six 11,000-gal liquid nitrogen tanks. Each tank is a double-walled vessel that separates the liquid nitrogen from the tank wall with an evacuated and insulated space. The vaporizing requirement for the nitrogen supply is met with water-bath vaporizers, heated with plant steam. The system includes interconnecting cryogenic piping and valves, water-circulating piping, and automatic controls. Nitrogen is distributed through the plant through a manifolded piping system. Delivery of nitrogen to the plant is either by truck on a daily basis or by rail car on a weekly basis. Plant nitrogen requirements are presented in Table 2.5.18.1.

Nitrogen required for coal storage blanketing was determined by calculating breathing losses and working losses. Since the coal-dolomite blend is relatively coarse in size (1/8” x 0) and its residence time in the lock hopper feed system is approximately 25 minutes at full load and 50 minutes at minimum load, the system is pressurized with air rather than nitrogen. However, upstream bunkers and hoppers are continuously made inert with nitrogen. At shutdown, the feed system is purged with nitrogen, forming an inert atmosphere to prevent spontaneous combustion/ fires in any coal residue remaining in the system. An 11,000-gallon storage tank contains 1,025,700 sft^3 nitrogen, and the six tanks provide for approximately six days of continuous operation at full load.

Table 2.5.18.1 Plant Nitrogen Requirements

Plant Use		lb/h
Stripping & fluidizing gas to operate the N valves for transfer of char from the carbonizer to the PCFB		4,130
Blanketing/inerting for all coal storage bunkers		450
Miscellaneous		100
	Total	4,680

Auxiliary Steam System. The auxiliary steam system is designed to supply the following during plant start-up:

- Steam to turbine seal system
- Steam to jet ejector
- Pegging steam to deaerator
- Building heating
- Miscellaneous steam for process, steam tracing, etc.

The auxiliary steam system supplies steam to the building heating system to maintain the temperature of the enclosed space well above the freezing point (approximately 45°F) during a winter plant outage. The system includes two 100 percent capacity boilers (auxiliary boilers), two 100 percent capacity feedwater pumps, and other related auxiliary equipment. Each auxiliary boiler is designed to burn No.2 fuel oil and can provide 100,000 lb/h steam at 250 psig saturated condition. Each feedwater pump is sized for 220-gal/min capacity at 700-ft discharge head. A separate connection is provided on the plant main deaerator for the feedwater suction. One auxiliary boiler is maintained in a standby condition when the plant is operating.

Industrial Waste Treatment System. The industrial waste treatment system for the baseline plant employs the following unit processes and operations:

▪ Flow Equa1ization. Contaminated runoff and leachate from a storm over a synthetic-membrane-lined coal pile (design based on the worst recorded storm in 10 years during a 24-hour period) is collected in a synthetic-membrane-lined earthen basin. Contaminated runoff from the dolomite storage pile is similarly collected in a separate earthen basin, which also receives contaminated yard drains. Both basins are designed to settle heavy sediment and equalize the peak flow rates from the "design" storm. A common pump station collects the discharge from the two basins, and the combined wastewater is pumped to the treatment system at a controlled rate.

  The treatment system employs a flow-equalization tank designed to equalize flow from the following sources:

  - Material storage pile runoff collection basins

  - Plant floor drain sumps which receive miscellaneous low-volume wastes, boiler blowdown, water treatment filter backwashes, and equipment cooling water

  - Discharge from a batch demineralizer-regenerant neutralization tank.

▪ Neutralization. Acidic wastewater is neutralized with hydrated lime in a two-stage system. Each fiberglass neutralization tank provides 10 minutes of reaction time at design flow. Each tank is equipped with a fixed-mount mixer, which completely mixes lime slurry with the wastewater, and with a pH probe and a controller, which automatically feeds lime slurry to the tank to control pH. An integral lime storage silo/lime slurry makeup system consists of a 50-ton lime silo, dry lime feeder, lime slurry tank, slurry tank mixer, and lime slurry feed pumps.

▪ Oxidation. Air is fed to the second-stage neutralization tank through a sparger pipe to oxidize any remaining ferrous iron to the ferric state. The air is supplied by a set of centrifugal blowers.

- Flocculation. Flocculation to promote particle size growth is provided in a fiberglass tank with a 10-minute retention time at design flow. The tank is equipped with a low-rev/min, variable-speed agitator. Polymer emulsion is drawn directly from a 55-gal drum and is diluted and fed to the flocculation tank by a polymer feed unit.

- Clarification/Thickening. Overflow from the flocculation tank enters a plate-type clarifier/thickener to separate suspended solids. Solids settle between the inclined plates to the thickener zone while the clarified supernatant liquid rises above the plates and discharges through flow-distribution orifices. The integral thickener section includes a picket-fence-type scraper mechanism, which further concentrates the sludge.

- Sludge Dewatering. Thickener sludge is piped to a holding tank; the procedure allows one-shift operation of the dewatering equipment and provides some further thickening. From the holding tank, the sludge is pumped to a plate-and-frame filter press for dewatering. The filter press provides a sludge cake of 30 wt% or higher dry solids. The filter press cake is dropped from the press into a sludge dump truck or dumpster. Filtration is returned to the flow-equalization tank. Cooling tower blowdown is collected and treated separately in an earthen basin to remove only the suspended solids before the blowdown is discharged to the receiving stream. The basin is designed for sludge removal by drag-line or front-end loaders and trucks.

2.5.19 Civil, Architectural, and Structural Plant Aspects

Building structures enclose the following plant components (Figure 2.3.2.1):

- Steam turbine
- Gas turbine
- Administrative area, controls complex, and maintenance area
- Auxiliary boilers
- Emergency generator
- Coal preparation equipment
- Selected areas of the steam generation module housing compressors and critical equipment
- Vehicle maintenance area
- Warehouses
- Makeup water pretreatment equipment
- Wastewater treatment equipment.

Additionally, supporting structures, foundations, or both, are provided for the balance-of-plant components shown in Figures 2.3.2.1 through 2.3.2.4.

Codes and Standards. The following are applicable in establishing structural engineering design criteria and steel and concrete construction requirements:

- The BOCA Basic Building Code, or comparable governing code, based on plant location.
- American National Standards Institute, "Minimum Design Loads for Buildings and Other Structures," ANSI A58.1.
- Local building codes, as applicable.

- American Concrete Institute
  -ACI 301, "Specification for Structural Concrete for Buildings"
  -ACI 318, "Building Code Requirements for Reinforced Concrete"
  -ACI 307, "Specification for the Design and Construction of Reinforced Concrete Chimneys"
- American Institute of Steel Construction
  -AISC, "Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings
  -AISC, "Code of Standard Practice for Steel Buildings and Bridges.

Building/Structure Description.

Structures.

- Building structures and equipment supports are steel framed, AISC Type 2 construction, with bracing for transfer of lateral forces.
- Building foundations are anticipated to be spread footings and mats, based on the assumption that rock will be found near the ground surface. Should the sub-surface exploratory program and geotechnical evaluation that would be conducted for the specific site prove differently, the most economical deep foundations would be selected at that time. Caissons, steel piles, cast-in-place or precast piles, and composite piles are possible alternatives if shallow foundations prove unfeasible.
- Barge unloading facility with dolphins (closely driven piles tied together) supporting reinforced-concrete caps, with a protective fendering system. Pile type will be determined upon evaluation of the geotechnical data.

Improvements to Civil Engineering Aspects.

- Surface Design.

  - The site is conceptually designed to conform, where feasible, with existing drainage patterns and contours.
  - Final earth grade adjacent to equipment and buildings will be at least 6 in. below the finished floor slab, with a minimum slope away from the building to normal grade of 0.5%.

- Access Roadways and Parking. The plant roads are all two lanes with a paved shoulder, with the pavement type and thickness selected based on the soil-bearing value of the subgrade and the anticipated vehicular axle loads. Road cross sections are crowned to achieve positive drainage; they slope away from the crown at a slope of at least 2%.

- Railroad Development. A railroad spur is extended from existing tracks into the plant site. All elements necessary to provide access to the plant site are furnished, including, for example, grading, ties, ballast, rails, switches, and road crossings.

- Coal Storage, Dolomite Storage, and Ponds. The material storage areas and the associated runoff ponds are protected to conform to all State and Federal regulations.
  - The coal pile and the coal pile runoff pond are lined with a 30-mil PVC liner.

- The dolomite storage runoff pond and the cooling tower pond are lined with a bentonite/clay liner.
- The construction pond is unlined.

Materials of Construction.

- Structural Steel. ASTM A36, unless otherwise dictated by design requirements
- Exterior Walls. Insulated metal siding
- Interior Partitions
  - Metal studs with two layers of gypsum board on each face
  - Concrete masonry units (normal weight) where required for fire barriers, stairwells, lavatories, and other selected locations
- Elevated Floors. Metal floor deck and reinforced concrete slab
- Roof. Metal deck, rigid insulation, and single-ply membrane roofing.
- Stairs. Open grating.

2.6 PLANT CONSTRUCTION AND SCHEDULE

The baseline plant incorporates many components already utilized by the process and power industries together with new PFB related components. The approach taken in estimating the baseline plant construction effort was to apply conventional practices to the former and to conceptually evaluate and, in some cases, apply engineering judgment in estimating the extent of shop fabrication, modularity, and field fabrication of the new components. The following steps were involved in this effort:

a. determine weights and outline dimensions of all major components
b. for those new components too large to ship, estimate the dimensions and weights of their modular shipping sections and the field work required to complete their fabrication
c. for all other shippable components estimate field work and construction costs using in-house data bases

The following maximum shippable dimensions were assumed for the baseline plant and were used to establish which components required field assembly:

a. Rail: 16 ft wide by 22 ft high by 85 ft long
b. Road: 10 ft wide by 13 ft 3 in high by 53 ft long

2.6.1 Major Components

Carbonizer-PCFB Island. Based on the above maximum shipping dimensions, the carbonizer and the PCFB boiler were found to be the only new technology components requiring field fabrication; the balance of their associated equipment were all shippable, shop fabricated components. Many of the latter utilize internal refractory linings that could be installed either in the shop or in the field, and shop installation was assumed for most of them. Those components that were relatively large or required field fabrication, e.g., the carbonizer, char collecting hoppers, and PCFB boiler waterwalls were assumed to be refractory lined in the field. Although the ceramic candle filter vessels were of a shippable size, their ceramic candles were assumed to be installed in the field.

Gas Turbine and Generator. The gas turbine generating system is conventional and utilizes modular construction to facilitate shipment and field assembly. The system was pre-assembled to the maximum extent permitted by shipping limitations. Where possible, subsystems were grouped and installed in auxiliary packages to minimize field assembly; those optimized packages were completely assembled and wired at the factory and required only interconnections at the site. The pipe rack assemblies provided as a part of these packages eliminated/minimized the need for on site construction work.

Steam Turbine and Generator. Because of its size and weight, the steam turbine generating system cannot achieve the modularity typical of its gas turbine counterpart. The LP case was shipped as an assembled component minus the rotor but it had to be disassembled to some extent to allow the installation of the rotor and other parts in the field. A similar situation existed for the HP/IP steam turbine section and the generator rotor. Although modular shipment of the exciter and main steam valves is possible, complete steam turbine generating system modularity is not recommended and was not used in this study.

2.6.2 Balance of Plant Components

The balance of plant (BOP) components of the baseline plant are similar to and, in many instances, identical to those already used in the process and power industries; for those components conventional construction approaches and costing were assumed.

2.6.3 Construction Schedule

A 500 MWe PC plant typically requires a 36-month construction schedule and involves such major activities as field fabrication/assembly of the boiler, regenerative air heater, electrostatic precipitator (ESP), scrubber, steam turbine, steam condenser, cooling towers, etc., and the setting of multiple pulverizers with primary, forced, and induced draft fans together with their ducting. Since the steam cycle of the baseline plant is about half that of the PC plant, its steam cycle components that will require field assembly, i.e., steam condenser, cooling tower, etc., will be smaller in size and require slightly shorter field assembly efforts. In addition the baseline plant does not require a regenerative air heater, ESP, or scrubber and instead replaces the ESP by 8 ceramic candle filter vessels. Functionally the gas turbine and main boost air compressor replace the PC plant fans and the baseline plant's two feedwater heaters and HRU replace the PC plant's 7 or 8 feedwater heaters.

The above simplistic comparison indicates the erection costs of the baseline plant should be significantly less than that of the PC plant and the Section 5 comparison of these two plants indicates a 45 percent savings in erection direct and indirect labor. Based on this difference in erection costs a shorter construction schedule could be expected for the baseline plant. The formulation of comprehensive shop fabrication, field fabrication, and erection plans and their integration into an optimized baseline plant construction schedule was beyond the scope of this update study. In the absence of such detailed plans and to be conservative, a 36-month construction schedule has been assumed for the baseline plant

2.7 PLANT OPERATING PHILOSOPHY

2.7.1. General

The high efficiency of the 2nd Generation PFB will move it to the front of a utility's dispatch order and, as a result, the subject plant is envisioned to be a baseload unit with occasional turndown to reduced load, rarely less than 50 percent load. Although operation as low as 25% may be possible, an analysis to determine the minimum permissible continuous load was beyond the scope of this study. At 25% load, the plant would probably be operating in a temporary holding pattern during a ramp-up or ramp-down.

Throughout the plant 50 to 100% load envelope the carbonizer will be operated at a fixed air to coal feed ratio designed to yield a nominal 1700EF temperature. The carbonizer through-put/coal feed rate will be increased or decreased as required to meet the gas turbine demand for higher or lower syngas flows respectively. Should there be a significant change in coal quality that affects the syngas yield per pound of coal fed, the carbonizer temperature can be trimmed by an adjustment in the air to coal feed ratio; a 1600EF to 1800EF range in operating temperature is permissible and will more than cover any change envisioned. The char transfer rate to the PCFB boiler will be controlled to maintain a constant level of char in the char hoppers so that the char transfer rate equals the char generation rate. The char feed to the PCFB boiler will be supplemented with direct coal feed to the PCFB as required to meet the steam turbine demand for steam while maintaining the PCFB between 1550EF (minimum load) and 1600EF (full load). The control of the PCFB boiler is typical of an atmospheric CFB boiler – superheat steam temperature will be controlled by attemperation whereas reheat temperature will be controlled by firstly adjusting the fluidizing velocity and hence varying the bed to tube heat transfer coefficients in the IntrexJ reheat units; secondly, the solids flow rate through the IntrexJ units can be varied if needed. Water spray is also available if immediate reheat temperature control becomes necessary.

The coal and dolomite are fed to the carbonizer and PCFB boiler via lock hopper type pneumatic transport feed systems; flow rates to each unit are controlled by varying the speed of volumetric feeders that are part of the vendor feed system package. The feeders will be calibrated on site yielding RPM versus flow rate curves and their injector vessels are placed on load cells to allow change in weight mass flow rate readings.

The plant air flow is determined by the positioning of the gas turbine inlet guide vanes; flow meters and control valves located in the gas turbine air compressor discharge line control and proportion the air flow to the carbonizer and PCFB boiler.

At the 50 percent load point the gas turbine inlet guide vanes have closed to reduce the plant airflow to 73 percent of the full load value. The gas turbine output is reduced to 106.3 MWe or 44.4 percent of full load and its exhaust temperature has dropped 114EF to 1015EF. The steam turbine output is reduced to 173.8 MWe or 67 percent of full load. With less syngas and hence char being produced coal is fed directly to the PCFB boiler to maintain the operating temperature and desired steam flow rate.

Since the gas turbine and steam turbine work together to determine the plant power output, an algorithm will be prepared for the plant that defines each turbine's operating conditions with concommitant carbonizer and PCFB boiler coal and air flow rates at various load points.

The PCFB boiler operates with excess air levels of 50 and 30 percent at 100 and 50 percent load, respectively, hence, there is an ample supply of air at all load points. Oxygen monitors, however, are still provided in the PCFB boiler flue gas and carbonizer syngas outlet streams to ensure that oxidizing and reducing conditions are maintained respectively in these units.

2.7.2 Plant Duty Cycle

The actual duty cycle imposed on the PFB baseline plant will vary according to the application. Because of the plant's high efficiency and depending upon the utility's nuclear capacity and daily load swings, it is quite likely the plant will have a high dispatch priority resulting in an 80 to 85% capacity factor. For the purpose of this conceptual design and to facilitate economic evaluations it is assumed the baseline PFB plant will operate with an 80 percent capacity factor and require one four week long planned annual outage per year. Since the plant will be predominantly operated as a baseload unit over its lifetime, features often incorporated to accommodate extended/ efficient low-load operation and rapid start-up/shut-down (e.g., variable pressure and 50 percent steam bypass) have not been included in the plant cost estimate.

2.7.3 Startup, Shutdown, and Normal Operation

Due to its high efficiency and low emissions, the PCFB plant has been designed to be and is expected to be dispatched as a base load unit. Part-load operation, apart from normal start-up and shutdown time intervals, is expected to be limited. The gas turbine will be operated at its maximum continuous rating, with the carbonizer trimmed to provide the syngas required for the topping combustor and the PCFB fired to meet steam turbine needs. The steam turbine will be designed to operate at its guarantee point at the maximum continuous system operating condition established by the gas turbine at ISO conditions (59EF, 14.7 psia ambient conditions). Some steam turbine margin will be available beyond the guarantee point, as the typical “valves-wide-open” capability, to accommodate the increased plant output that may be available at reduced ambient temperatures. A detailed analysis must be conducted at the minimum expected ambient temperature so that components are sized properly.

From a system operations and controls perspective, the gas turbine represents the leading component. The carbonizer subsystem operates to satisfy the gas turbine demand for syngas, based on the load setpoint selected. The other components follow, as required. In the base load mode of operation, stable operation of all components is expected, with gradual minor changes in operating parameters to accommodate changes in ambient temperature, barometric pressure, fuel composition, etc. Operation at 50 percent load is characterized by full closure of the gas turbine compressor inlet guide vanes and a several hundred degree reduction in gas turbine rotor inlet temperature. Steady state load conditions between 50 and 100 percent are characterized by some reduction in rotor inlet temperature and partial or full closure of the compressor inlet guide vanes. Preparation of detailed schedules for system operating parameters over the load range is beyond the scope of this report.

The following brief discussion illustrates start-up, shutdown, and some aspects of plant load changing including sudden loss of load (generator trip or loss of grid demand).

Equipment, piping, and valves related to the startup, control, turndown, and shutdown of the baseline plant are shown schematically in Figure 2.7.3.1. Acronyms and abbreviations used throughout this document are defined in Table 2.7.3.1. All references to valves and other components in this report refer to this figure and table.

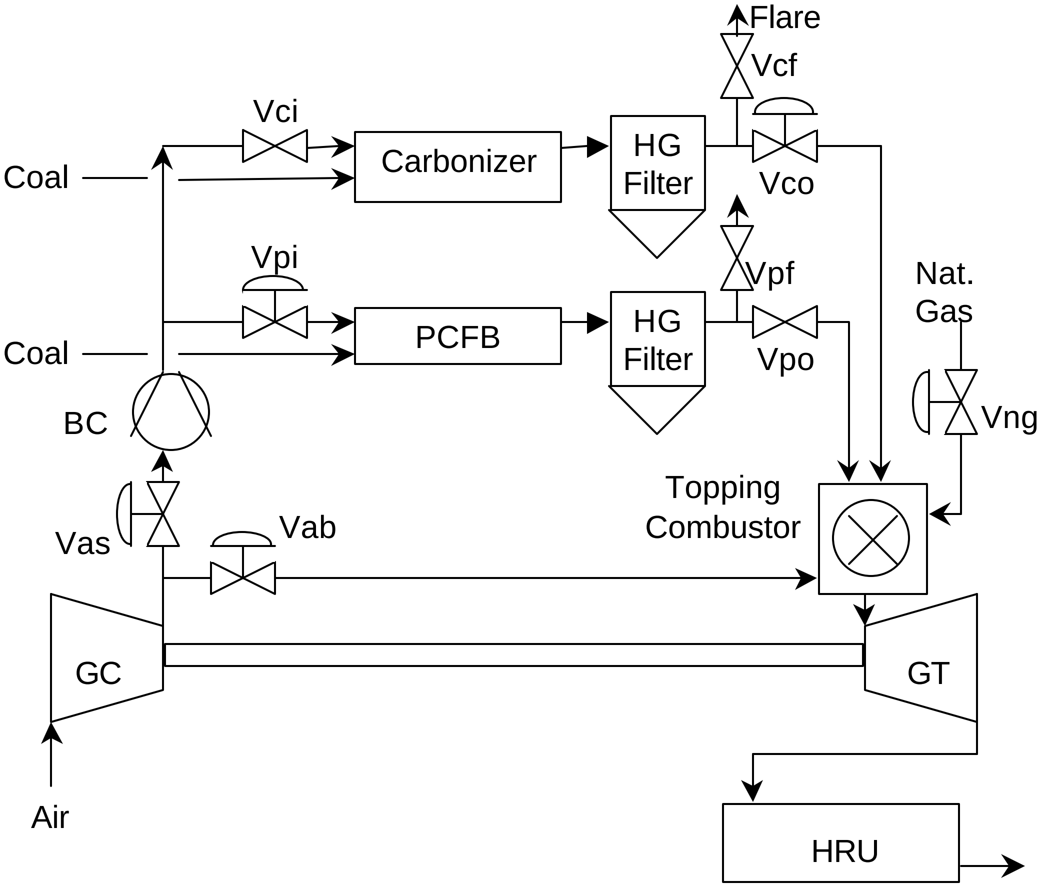

Figure 2.7.3.1 – Plant Gas Flow Control Diagram

Table 2.7.3.1 Abbreviations and Acronyms for Gas Flow Control Valves

APFBC	Advanced Pressurized Fluidized Bed Combustion
BC	Boost Compressor to pressurize the PCFB
GC	Gas turbine compressor
GT	Gas turbine expander
HG	Hot Gas (Filter)
HRU	Heat Recovery Unit
MASB	Multi-Annular Swirl Burner, which is part of the Topping Combustor
PCFB	Pressurized Circulating Fluidized Bed
TC	Topping Combustor
Vab	Compressed air bypass valve
Vas	Compressed air supply valve
Vcf	Carbonizer syngas flare valve
Vci	Carbonizer air shutoff valve
Vco	Carbonizer syngas control valve
Vng	Natural gas fuel control valve
Vpf	PCFB (vitiated air) vent valve
Vpi	PCFB air control valve
Vpo	PCFB (vitiated air) outlet valve

Plant Startup. Table 2.7.3.2 describes the cold startup procedure for the complete plant, including the proposed use of bypasses. Maximum and minimum air flows to and from the W501G compressor and turbine during startup and operation are consistent with normal SWPC practice.

Similar procedures would be used for warm startup, such as would occur after an overnight or weekend shutdown, or a hot startup, such as would occur after a brief shutdown following a generator trip or component failure that is quickly remedied. Since equipment temperatures are warmer at the beginning of warm and hot starts, the duration of each step is shorter than for cold starts.

Table 2.7.3.2 Plant Cold Start Sequence

Step	Activity	Hours	Valve Lineup
1	Start the gas turbine on natural gas, connect it to the power grid in simple cycle, and increase power to about 15% load. (15% load is the suggested point at which the transition-cooling medium is normally changed from air to steam. Combustor shell pressure and temperature are 165-170 psia and 665-670°F at this 15% load point.)	Normal start time is 20 minutes	Vab open to TC Vas closed to BC Vpi closed Vpf closed Vpo closed Vci closed Vcf closed Vco closed Vng open
2	Start BC. Use compressed air from the gas turbine to pressurize the PCFB and its HGF to the same pressure as the topping combustor (TC).	Determined by vessel and piping volumes and air feed rate.	Same as previous step plus: open Vas
3	Using compressed air from the gas turbine together with a start-up burner at the PCFB, establish air flow and heat the PCFB to approximately 1200°F with exhaust returned to the TC.	~4 hrs	Same as previous step plus: open Vpo
4	Establish PCFB coal feed and ignition, gradually shut off the start-up burner, and heat the PCFB and filter approximately 1600 °F.	~6 hours	Same as previous step plus: Trim Vas and Vab to increase flow to TC. Trim Vpi
5	Begin natural-gas-topped PCFB operation.		Same as previous step plus: close Vab
6	Use compressed air from the gas turbine to pressurize the carbonizer and its HGF to the same pressure as the topping combustor (TC).	Determined by vessel and piping volumes and air feed rate.	Same as previous step plus: open Vci
7	Using compressed air from the gas turbine together with a start-up burner in the carbonizer, heat the carbonizer and bed to about 1200 °F at a rate of approximately 150 °F/hr. Activate the slurry water spray as required to keep the temperature of the syngas entering the filter below 600 °F to avoid combustion of any char inadvertently remaining in the downstream system. Carbonizer warm-up exhaust gas is sent to flare.	~6 hrs	Same as previous step plus: open Vcf
8	Establish carbonizer coal feed and ignition, immediately ramp to stoichiometric conditions. Gradually turn off the start-up burner and heat the carbonizer and hot gas filter to approximately 1600 °F at a rate less than 150 °F/hr.	~6 hrs	Same as previous step. Trim Vci and Vcf as required.
9	To convert from stoichiometric to substoichiometric operation. Ramp coal flow rate and adjust syngas pressure to match TC pressure.	~2 hrs	Same as previous step. Trim Vci and Vcf as required.
10	Begin syngas-topped PCFB operation. Shut off natural gas flow to combustion chamber.		Same as previous step plus: Reduce Vng to zero open Vco close Vcf and Vng

Plant Turndown. Table 2.7.3.3 describes the tentative turndown procedure for the complete plant. Maximum and minimum air flows to and from the W501G compressor and turbine will be consistent with normal SWPC practice.

Table 2.7.3.3 Plant Turndown Sequence

Step	Activity	Hours	Valve Lineup
1	Reduce gas turbine load by reducing syngas feed rate while closing the GT guide vanes to maintain constant exhaust gas temperature. Reduce carbonizer coal and char flows while increasing coal feed to PCFB to maintain the PCFB temperature around 1600 ^{o}F. Operate Vpi and Vco together to maintain proper flow balance between carbonizer and PCFB. (At the end point of this step, GT inlet air flow is about 70-75% of GT baseload value, and GT net power is about 65% of GT baseload value. Combustor shell pressure and temperature are 200-210 psia and 720-730 ^{o}F.)		Vas open to BC Vab closed to TC Trim Vpi Vpf closed Vpo open Vci open Vcf closed Trim Vco Vng closed
2	Reduce syngas feed rate to reduce GT power output to about 15% GT load. (At the end point of this step, GT net power is about 16% of GT baseload value. Since GT power is above 15%, the transition cooling medium does not need to change from steam to air. Combustor shell pressure and temperature are 165-170 psia and 665-670 ^{o}F.)		Same as in previous step.
3	Reduce coal flow to PCFB to reduce PCFB steam generation. GT conditions unchanged.		Same as in previous step.

Plant Normal Shutdown. Table 2.7.3.4 describes the normal shutdown procedure for the complete plant. Maximum and minimum air flows to and from the W501G compressor and turbine during shutdown are consistent with normal SWPC practice.

Table 2.7.3.4 Plant Normal Shutdown Sequence

Step	Activity	Hours	Valve Lineup
1	Reduce power to 25% of rated plant load using the procedure described under "Plant Turndown."		Vas open to BC Vab closed to TC Trim Vpi Vpf closed Vpo open Vci open Vcf closed Trim Vco Vng closed
2	Gas turbine power will be just above 15% of rated load. Switch from steam cooling to air cooling of the GT transition.		Same as prior step.
3	Cut off coal and air flow to the carbonizer and char transfer to PCFB.		Same as prior step, plus: Close Vci, Vco and char transfer valves
4	Open natural gas flow to TC to enable GT operation after the syngas was pulled out.		Same as prior step, plus: Open Vng
5	With the carbonizer isolated and topping combustion ended, reduce coal flow to the PCFB. Switch on the start up burner during the reduction in coal flow (coal will be cut off at 1450 ^{o}F) to provide reduced steam flows to hasten the cool-down of the steam turbine. Continue minimum steam generation via the startup burner.		Same as prior step.
6	Once the steam turbine has cooled, Shut off the start up burner.		Same as prior step.
7	Divert part of the air flow from the PCFB to the TC. Purge the PCFB leg of the plant with air.		Same as prior step, plus: Partially open Vab Partially close Vas
8	As the PCFB leg of the plant depressures to ambient, simultaneously depressure the carbonizer leg of the plant to the flare.		Same as prior step, plus: Open Vcf
9	Once the carbonizer leg of the plant has depressurized, purge it of all syngas by twice pressurizing it to 3 bar with nitrogen, then vent to flare to remove remaining syngas.		Same as prior step, plus: Close Vcf, then Open Vcf
10	Drain and cool all char from the carbonizer leg of the plant and transfer to char day bins at PCFB boiler.		
11	Plant cool down can be speeded up by using: a. Cool Down Blower BI-101 to blow cold air through the PCFB leg of the plant. b. Pressurizing carbonizer leg of plant to 3 bar with nitrogen and using the syngas recycle system to continuously circulate cool nitrogen.		

Plant Abnormal Shutdown. Loss of load from either a generator trip or loss of grid demand is expected to represent the most severe transient for the plant. Table 2.7.3.5 presents a shut down procedure for such an occurance; this procedure is essentially identical to that developed for and found to be suitable for a 2nd Gen PFB plant operating with a Siemens Westinghous 501F gas turbine [2-1]. Maximum and minimum air flows to and from the W501G compressor and turbine during abnormal shutdown are consistent with normal SWPC practice.

Table 2.7.3.5 Plant Abnormal Shutdown Sequence

Step	Activity	Hours	Valve Lineup
1	The following valve actions happen simultaneously. Shunt compressor exit to topping combustor (Switch valve Vas & Vab) Shut off air to carbonizer (Close Vci) Shut off air to PFBC (Close Vpi) Depressure plant at slow controlled rate via valves Vcf and Vpf		Vas closed to BC Vab open to TC Vpi closed Vpf open Vpo closed Vci closed Vcf open Vco closed Vng closed
2	Purge and cool down plant by steps 9 through 11 of Table 2.7.3.4.		

2.8 RELIABILITY AND AVAILABILITY ASSESSMENT

The rationale for undertaking a reliability, availability, and maintainability (RAM) assessment of a 2nd Generation PFB Combustion Plant is that, like any power-generating unit, it is capital-intensive and a complex combination of electrical and mechanical components subject to random failure as well as wear. Additionally, a highly efficient unit such as the baseline plant will be high on any utility's commitment schedule (i.e., it will be scheduled to operate whenever it is capable of operation, at the highest capacity available). For these reasons it is desirable not only to determine what proportion of time the baseline plant can produce power, but also to take cost-effective measures to increase plant availability to the maximum feasible level.

RAM techniques have been applied in the electric utility industry for several decades and have reached a mature state, with standard and generally accepted definitions of terminology and methodology. The North American Electric Reliability Council (NERC) has a historical database on the performance of power plants and their components for all present-day methods of power generation, ranging from fossil and nuclear base-load steam plants to load-leveling units such as pumped storage. The Council publishes Generating Availability Data Summary reports, which include the annual and 10-year performance of various types of generating units and their components. EPRI has developed assessment methodologies for advanced generation technologies, such as gasification combined cycles, and has developed computer programs such as UNIRAM for RAM assessment.

The original baseline plant design was the subject of a detailed RAM analysis that is presented and described in [ES-1]; that study used utility-accepted RAM methodology and EPRI's UNIRAM computer code. Component data from the NERC data summary and EPRI databases supplemented by engineering estimates for new components, were used to determine the RAM indices for the baseline plant. In addition to overall plant RAM measures, the criticality ranking option of the UNIRAM computer code was used to determine the 15 components that have the greatest impact on plant reliability.

A repeat detailed RAM analysis of the updated baseline plant design was beyond the scope of this study. The original analysis found that an n^{th}/mature 2^{nd} Generation PFB Combustion Plant should perform similar to a state-of-the-art PC plant with sulfur-removal equipment and should be acceptable to utility planners as an alternative technology for meeting NSPS when installing additional system capacity. Since the updated plant design is technologically and component-wise essentially identical to the original baseline design, this finding still appears reasonable.

Section 3

PLANT ECONOMIC ANALYSIS

This section describes the approach, basis, and methods that were used to perform an economic evaluation of the 2nd Gen PFB baseline plant. The results of this effort are presented at the composite level--expressed as the levelized Cost of Electricity (COE), and at the component level--consisting of the capital cost and operating costs and expenses, including fuel cost. Results of this evaluation based on a 30-year life are summarized in Table 3.0.1.

The evaluation approach is summarized in the following section. Succeeding discussions examine the components of the COE in the order they were developed and presented in Table 3.0.1.

*Table 3.0.1 Summary of Capital Costs and Economics of 2nd Gen PFB Baseline Combustion Plant**

Item	**Year 2002 Dollars**	**Unit Cost**
Total Plant Cost (TPC)	517,182,000	1,083 $/KW
Operating and Maintenance	20,994,000	44.0 $/kW-yr
Consumables	10,030,000	3.00 mills/kWh
Fuel	29,957,000	8.95 mills/kWh
Levelized Busbar COE	---	41.9 mills/kWh

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*Based on net plant electrical output of 477.5 MW, an 80% capacity factor, a total plant cost (TPC) expressed in January 2002 dollars, and first-year costs expressed in January 2002 dollars. COE levelized over 30 years.

3.1 EVALUATION APPROACH

The figure of merit in this evaluation is the COE. The capital cost, operating costs and expenses, and the COE were established consistent with EPRI Technical Assessment Guide methodology, and the plant scope identified in Section 2. The specific components of the COE, identified in Figure 3.1.1, indicate the proportion of their contribution to COE. The cost of each component was quantitatively developed to enhance credibility and establish a basis for subsequent comparisons and modification as the technology is further developed.

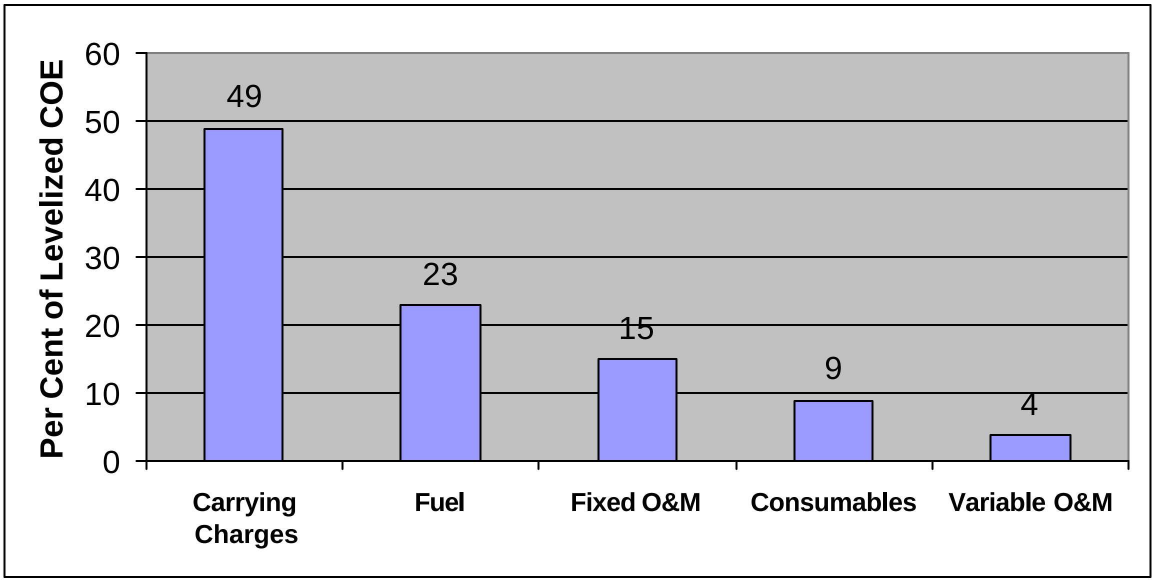

Figure 3.1.1 Components of Levelized Plant COE

The carrying charge value, the largest component of the COE, is determined directly as the product of the fixed charge rate and the capital cost of the plant. The approach to evaluating the capital cost of the plant consists of evaluating the installed equipment and material cost of each identified component of the plant. The sum of these individual costs, added to the estimate of engineering services, contingencies, escalation and financing charges, and owner's costs, yielded the total capital requirement (TCR) for the plant. The general estimate basis and assumptions are identified below:

- Total plant cost values are expressed in January 2002 dollars.
- The estimate represents a mature technology plant, or "nth plant" (i.e., it does not include costs associated with a first-of-a-kind plant).
- The estimate represents a complete power plant facility with the exception of the exclusions listed in Section 3.7.
- The estimate boundary limit is defined as the total plant facility within the "fence line," including the barge unloading pier but terminating at the high side of the main power transformers.
- Site location is within the Ohio River Valley, southwestern Pennsylvania/eastern Ohio, but not specifically sited within the region.
- Terms used in connection with the estimate are consistent with the EPRI TAG.

- Costs are grouped according to a process/system-oriented code of accounts; all reasonably allocable components of a system or process are included in the specific system account in contrast to a facility, area, or commodity account structure.

- The basis for equipment, materials, and labor costing is described further below.

- Design engineering services, including construction management and contingencies basis, are examined in Section 3.4.

- The fuel cost component of the COE was developed on the basis of a straightforward calculation involving the plant size, plant heat rate, coal heating value, coal unit cost, plant annual operating hours, and a levelizing factor. Section 3.9.5 contains a more specific treatment of this calculation.

- The operating and maintenance expenses and consumables costs were developed on a quantitative basis.
  - The operating cost is determined on the basis of the number of operators required.
  - The maintenance cost is evaluated on the basis of relationships of maintenance cost to initial capital cost.
  - The cost of consumables is determined on the basis of individual rates of consumption, the unit cost of each consumable, and the plant annual operating hours.

  Each of these expenses and costs is determined on a first-year basis and levelized at the 10-year life of the plant through application of a levelizing factor to determine the value that forms a part of the COE. These costs and expenses are individually examined in greater detail in Section 3.9.

3.2 CAPITAL COSTS

The capital cost, specifically referred to as TCR for the mature second-generation PFB combustion power plant, was estimated using the EPRI methodology identified in Figure 3.2.1. The major components of TCR consist of bare erected cost, total plant cost (TPC), total plant investment (TPI), and owner's costs.

The capital cost was determined through the process of estimating the cost of major equipment items, components, and bulk quantities identified. A Code of Accounts was developed to provide the required structure for the estimate. The Code facilitates the consistent allocation of individual costs that were developed by various companies. The selected code structure, though not identical, is similar to other PFB estimate code structures to permit cost comparisons if desired. The Code facilitates recognition of estimated battery limits and the scope included in each account. The summary level of this Code is presented in Table 3.2.1.

The result of the evaluation process, to the level of TPC, is presented in summary form in Table 3.2.2.The development of the values that constitute the TPC level of the capital cost estimate as well as the TPI and TCR levels, is described in the subsections that follow. These subsections are supplemented by identification of specific estimate exclusions and discussions of the approach used to verify that the resultant PCFB combustion plant estimate is a good representation of expected capital cost.

3.3 BARE ERECTED COST

The bare erected cost level of the estimate, also referred to as the sum of process capital and general facilities capital, consists of the cost of: factory equipment, field materials and supplies, direct labor, indirect field labor, and indirect construction costs.

Factory equipment or major equipment costing was determined by the various project team members and Parsons determined the overall plant costs and economics. The team member scope of supply was:

- Carbonizer and related equipment: Foster Wheeler
- PCFB Boiler and related equipment: Foster Wheeler
- Ceramic Candle/Barrier Filters: Siemens Westinghouse
- Combustion Turbine Package: Siemens Westinghouse
- Steam Turbine/Generator: Parsons
- Balance-of-Plant (BOP) Major Systems: Parsons

Parsons obtained budgetary quotes for several major BOP equipment items. Upon receipt of each individual quote, its value was compared with the expected value for that component or system to confirm that cost levels were appropriate and to verify that the quoted scope represented the required scope. The list of major BOP equipment that was costed on the basis of vendor quotes includes:

- Coal and sorbent handling, including the barge unloader
- Coal, sorbent, and ash storage silos
- Deaerator and heat exchangers
- Major pumps, blowers, and compressors
- Water-treating packages
- Oil and water storage tanks
- Stack
- Condenser
- Cooling tower

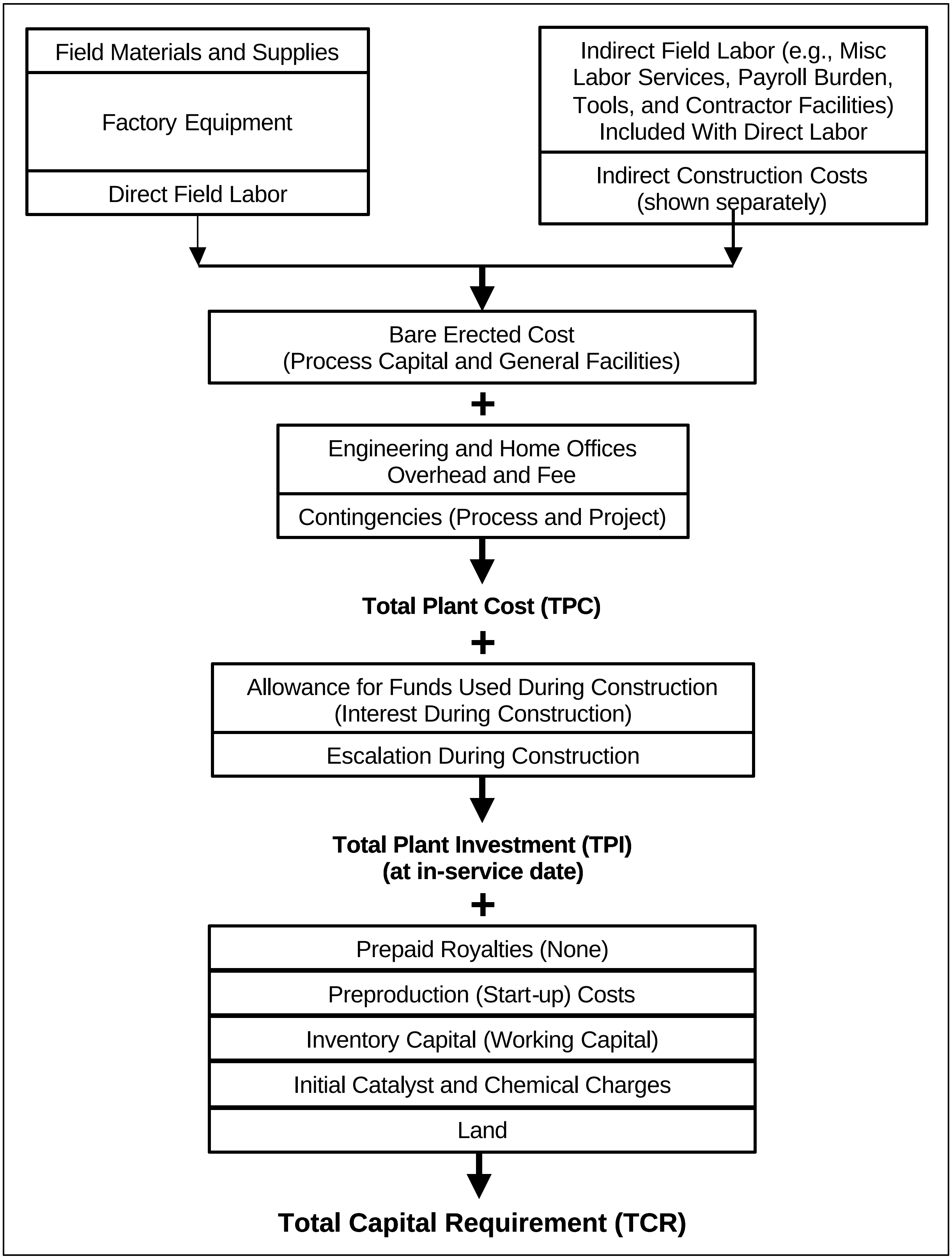

Figure 3.2.1 Components of Capital Cost

Table 3.2.1 Code of Direct Accounts Summary

Account Number	Account Title
1	COAL and SORBENT HANDLING
1.1	Coal Receiving and Unloading Equipment
1.2	Coal Stackout and Reclaim Equipment
1.3	Coal Storage Bin and Yard Crushers
1.4	Other Coal-Handling Equipment
1.5	Sorbent Receiving and Unloading Equipment
1.6	Sorbent Stackout and Reclaim Equipment
1.7	Sorbent Conveyors
1.8	Other Sorbent-Handling Equipment
1.9	Coal and Sorbent Handling Foundations
2	COAL and SORBENT PREPARATION and FEEDING
2.1	Coal Crushing and Drying Equipment
2.2	Coal Conveyor/Storage
2.3	Coal Injection System
2.4	Miscellaneous Coal Preparation and Feed
2.5	Sorbent Preparation
2.6	Sorbent Storage and Feed Equipment
2.7	Sorbent Injection System
2.8	Booster Air Supply System
2.9	Coal and Sorbent Foundations
3	FEEDWATER and MISCELLANEOUS SYSTEMS and EQUIPMENT
3.1	Feedwater System
3.2	Water Makeup and Pretreating
3.3	Other Feedwater Subsystems
3.4	Service Water Systems
3.5	Other Boiler Plant Systems
3.6	Fuel Oil Supply System and Natural Gas
3.7	Waste Treatment Equipment
3.8	Miscellaneous Power Plant Equipment
4	CARBONIZER and PCFB BOILER
4.1	Carbonizer Island
4.2	PCFB Boiler Island
4.3	Open
4.4	Interconnecting Pipe
4.5	Miscellaneous PCFB Equipment
4.6	Other PCFB Boiler Equipment
4.7	Open
4.8	Major Component Rigging
4.9	Foundations and Supports

Table 3.2.1 (continued) - Code of Direct Accounts Summary

Account Number	Account Title
5	HOT GAS CLEAN-UP and PIPING
5.1	Carbonizer Candle Filters
5.2	PCFB Candle Filters
5.3	Hot Gas Piping
5.4	Blowback Gas and Air Systems
5.9	Foundations and Supports
6	COMBUSTION TURBINE and ACCESSORIES
6.1	Combustion Turbine Generator
6.2	Balance Including
	Booster Air Systems
	Compressed Air Piping
	Combustion Turbine Foundations
7	HRU, DUCTING, and STACK
7.1	Heat Recovery Unit
7.2	Balance Including
	HRU Accessories
	Ductwork
	Stack
	HRU, Duct and Stack Foundations
8	STEAM TURBINE GENERATOR
8.1	Steam Turbine Generator and Accessories
8.2	Balance Including
	Turbine Plant Auxiliaries
	Condenser and Auxiliaries
	Steam Piping
	TG Foundations
9	COOLING WATER SYSTEM
9.1	Cooling Towers
9.2	Circulating Water Pumps
9.3	Circulating Water System Auxiliaries
9.4	Circulating Water Piping
9.5	Make-Up Water System
9.6	Component Cooling Water System
9.9	Circulating Water Foundations

Table 3.2.1 (continued) - Code of Direct Accounts Summary

Account Number	Account Title
10	ASH/SPENT SORBENT HANDLING SYSTEMS
10.1	PCFB Bottom Ash
10.2	PCFB Fly Ash
10.3	Open
10.4	High-Temperature Ash Piping
10.5	Other Ash-Recovery Equipment
10.6	Ash Storage Silos
10.7	Ash Transport and Feed Equipment
10.8	Miscellaneous Ash-Handling Equipment
10.9	Ash/Spent Sorbent Foundations
11	ACCESSORY ELECTRIC PLANT
11.1	Generator Equipment
11.2	Station Service Equipment
11.3	Switchgear and Motor Control
11.4	Conduit and Cable Tray
11.5	Wire and Cable
11.6	Protective Equipment
11.7	Standby Equipment
11.8	Main Power Transformer
11.9	Electrical Foundations
12	INSTRUMENTATION and CONTROLS
12.1	Carbonizer and PCFB Boiler Control Equipment
12.2	Combustion Turbine Control
12.3	Steam Turbine Control
12.4	Other Major Component Control
12.5	Signal Processing Equipment
12.6	Control Boards, Panels, and Racks
12.7	Computer and Accessories
12.8	Instrument Wiring and Tubing
12.9	Other Instrumentation and Control Equipment
13	IMPROVEMENTS TO SITE
13.1	Site Preparation
13.2	Site Improvements
13.3	Site Facilities

Table 3.2.1 (continued) - Code of Direct Accounts Summary

Account Number	Account Title
14	BUILDINGS and STRUCTURES
14.1	Combustion Turbine Area
14.2	Steam Turbine Building
14.3	Administration Building
14.4	Circulating Water Pump House
14.5	Water-Treatment Buildings
14.6	Machine Shop
14.7	Warehouse
14.8	Other Buildings and Structures
14.9	Waste-Treatment Buildings and Structures

Table 3.2.2 Total Plant Cost Summary of 477.5 MWe Baseline Plant (Thousands of Year 2002 Dollars)

Acc't		**Equipment**	**Material**	**Labor**		**Bare Erected**	**Eng'g CM**	**Continge ncy**		**Total Plant Cost**	
No.	**Item / Description**	**Cost**	**Cost**	**Direct**	**Indirect**	**Cost**	**H.O.& Fee**	**Process**	**Project**	**$**	**$/kW**
1	Coal & Sorbent Handling	$10,153	$2,347	$5,265	$369	$18,133	$1,632	$0	$2,965	$22,730	$48
2	Coal & Sorbent Prep & Feed	$17,534	$2,756	$7,322	$513	$28,124	$2,531	$1,533	$4,598	$36,786	$77
3	Feedwater & Misc BOP Systems	$7,366	$6,320	$6,213	$435	$20,334	$1,830	$0	$3,325	$25,489	$53
4	Carbonizer & PCFB Boiler Island	$5,382	$3,188	$13,986	$979	$71,536	$64,38	$10,832	$11,696	$100,502	
5	Hot Gas Cleanup & Piping	$25,344	$4,785	$9,390	$657	$40,177	$3,616	$8,758	$6,569	$59,120	$124
6	Combustion / Turbine & Accessories										
6.1	Combustion Turbine Generator	$50,000	$0	$2,925	$205	$53,130	$4,782	$5,791	$8,687	$72,389	$152
6.2	Balance	$1,159	$1,031	$1,224	$86	$3,499	$315	$0	$572	$4,386	$9
7	HRU, Ducting, & Stack										
7.1	Heat Recovery Unit	$10,008	$0	$1,821	$127	$11,957	$1,076	$0	$1,955	$14,988	$31
7.2	Balance	$5,501	$634	$4,680	$258	$11,072	$997	$0	$1,810	$13,879	$29
8	Steam Turbine Generator										
8.1	Steam TG & Accessories	$25,395	$0	$1,828	$128	$27,351	$2,462	$0	$4,472	$34,284	$72
8.2	Balance	$1,632	$5,349	$4,087	$286	$11,355	$1,022	$0	$1,856	$14,233	$30
9	Cooling Water System	$4,201	$4,419	$6,179	$433	$15,232	$1,371	$0	$2,490	$19,093	$40
10	Ash/ Spent Sorbent Handling Systems	$8,587	$5,154	$5,277	$369	$19,387	$1,745	$1,057	$3,170	$25,358	$53
11	Accessory Electric Plant	$10,349	$2,823	$7,506	$525	$21,203	$1,908	$1,156	$3,467	$27,733	$58
12	Instrumentation & Controls	$7,524	$1,598	$6,152	$431	$15,704	$1,413	$857	$2,568	$20,542	$43
13	Improvements to Site	$0	$2,829	$5,410	$449	$8,688	$782	$0	$1,421	$10,891	$23
14	Buildings & Structures	$0	$6,001	$5,411	$379	$11,790	$1,061	$0	$1,928	$14,779	$31
	Total Plant Cost	$238,134	$49,234	$94,675	$6,628	$388,671	$34,980	$29,983	$63,548	$517,181	$1,083

The list of quoted equipment is not complete, but it does identify the major quotes received. The table presented at the end of this subsection indicates that 80 percent of the plant equipment costs were quoted and includes recognition of quotes furnished by Foster Wheeler and Siemens Westinghouse.

Other equipment, minor secondary systems, and materials were estimated by Parsons on the basis of models developed from data consisting of reference budgetary level vendor quotes or in-house data consisting of other project cost data and relationships, catalog data, and standard utility unit cost data.

On an estimating discipline basis, other materials and equipment were estimated in the following manner: Piping costs for major systems were developed by estimating the required quantities and applying appropriate unit costs and unit manhours. Minor piping and system costs were determined from models based on data for similar systems that were adjusted for length and capacity by appropriate scaling factors. Electrical and instrumentation and control (I&C) equipment was evaluated on the basis of reference estimates of similar scope that were based on quotes or current in-house cost data. The electrical and I&C bulk commodities (i.e., wire and cable, conduit, cable tray, terminations) were determined on a basis similar to that used for evaluating the electrical equipment. Civil and structural items were estimated on the basis of reference estimates that utilized conceptual quantities that were derived from layout plot plan and elevation drawings of the baseline plant.

The labor cost to install the PFB equipment and materials was estimated on the basis of a combination of reference labor cost values and unit man hours and manhours applied to the appropriate quantities to arrive at total installation manhours for each item or bulk quantity. The resulting reference manhours were evaluated using a variety of wage rates.

In general, the labor cost in the estimate is based on a comprehensive subcontract approach and includes direct labor costs plus fringe benefits and allocations for contractor expenses and markup. In addition, a craft labor mix was specified for each major work operation with a fraction of cost allocated to provide for the cost of construction equipment required for that work operation.

The indirect labor cost was estimated at 7 percent of direct labor to recognize the cost of construction services and facilities not provided by the individual contractors. The latter cost represents the estimate for miscellaneous temporary facilities such as construction road and parking area construction and maintenance; installation of construction power; installation of construction water supply and general sanitary facilities; and general and miscellaneous labor services such as jobsite cleanup and construction of general safety and access items.

Figure 3.3.1 indicates the contribution of each category of cost in bare erected cost as well as an indication of the ratio of quoted equipment to total equipment and total bare erected cost.

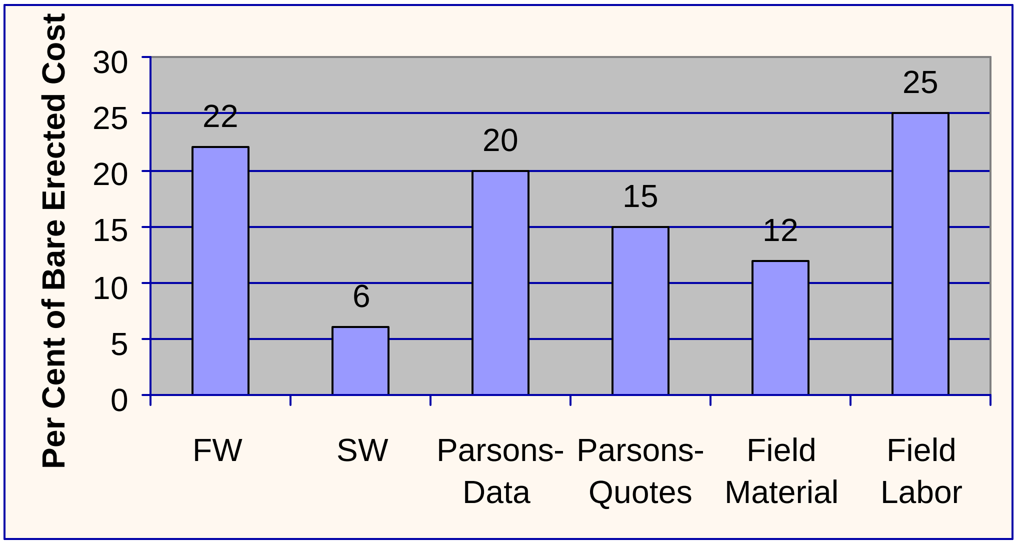

Figure 3.3.1 Components of Bare Erected Costs

3.4 TOTAL PLANT COST (TPC)

The TPC level of the estimate consists of the bare erected cost plus engineering and contingencies. Figure 3.4.1 indicates the relative contribution of each component of TPC.

The engineering costs shown in Table 3.2.2 represent the cost of architect/engineer services for design/drafting and project construction management services. The cost for the PFB plant engineering was determined at 9 percent applied to the bare erected cost on an individual account basis. The cost for engineering services provided by the equipment manufacturers and vendors is included directly in the equipment costs.

Allowances for process and project contingencies are also considered as part of the TPC. Some of the process technology used in the various systems is still in the development stage. Continuing process development tends to increase the cost of plant components as problems are discovered and resolved. In an attempt to account for the uncertainty in equipment design, performance, and cost, a process contingency was added to the estimated cost of pertinent components and systems.

The criteria for determining the process contingency factors was engineering judgment together with the EPRI TAG guidelines. Specific factors were applied to the non-commercial components and the resulting percentages by account level are shown in Table 3.4.1.

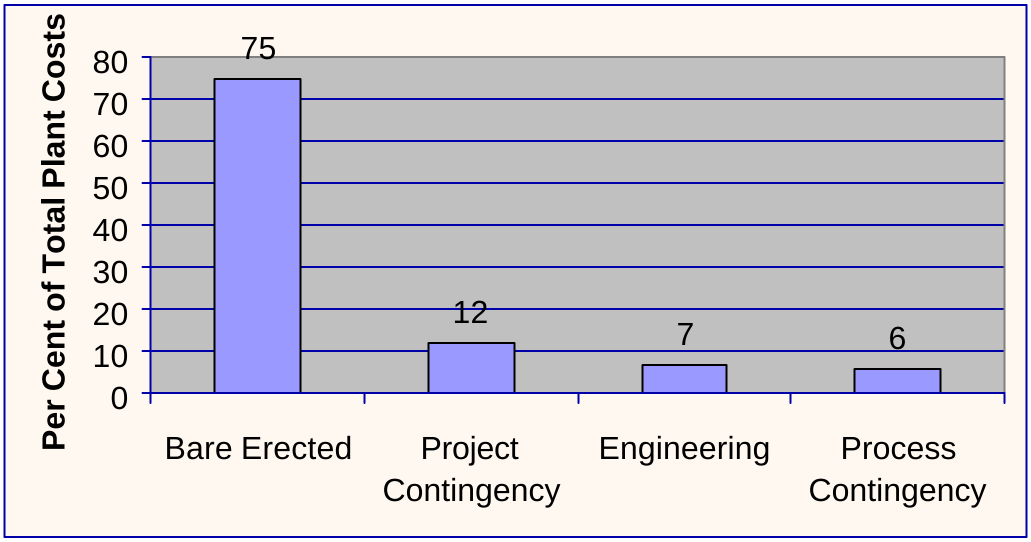

Figure 3.4.1 Components of Total Plant Costs

Table 3.4.1 Process and Project Contingency Factors

Item/Description	**Contingency Factors (%)**	
	Process	**Project**
COAL AND SORBENT HANDLING	0	15
COAL AND SORBENT PREPARATION AND FEED	5	15
FEEDWATER AND MISCELLANEOUS BOP SYSTEMS	0	15
CARBONIZER AND PCFB BOILER		
Carbonizer Island	15	15
PCFB Boiler Island	15	15
Other PCFB Equipment	0	15
HOT GAS CLEANUP AND PIPING	20	15
COMBUSTION TURBINE/ACCESSORIES		
Combustion Turbine Generator	10	15
Combustion Turbine Accessories	10	15
HRU, DUCTING AND STACK		
Heat Recovery Steam Generator	0	15
HRU Accessories	0	15
STEAM TURBINE GENERATOR		
Steam Turbine Generator and Accessories	0	15
Turbine Plant Auxiliaries	0	15
COOLING WATER SYSTEM	0	15
ASH/SPENT SORBENT HANDLING SYSTEM	5	15
ACCESSORY ELECTRIC PLANT	5	15
INSTRUMENTATION AND CONTROL	5	15
IMPROVEMENTS TO SITE	0	15
BUILDINGS AND STRUCTURES	0	15

At the level of TPC, the net effect of process contingency is an increase in TPC of nearly 63 $/kW or nearly 6 percent. The equivalent change at the TCR level is 6-1/2 percent, since all items are not directly affected by a change in TPC. At the level of COE the result would be 3 percent lower or approximately 36.7 mills/kWh. (In actuality the process contingency was slightly higher than the above because in the cost roll up it is subject to the 9 percent engineering and 15 percent project contingency charges.)

Consistent with conventional power plant practices, a general project contingency was added to the total plant cost to cover project uncertainty and the cost of any additional equipment that could result from a detailed design. Based on EPRI criteria, the cost estimate contains elements of Classes I, II, and III level estimates. As a result, on the basis of the EPRI guidelines and prudent judgment, a nominal value of 15 percent was used to arrive at the plant nominal cost value. This project contingency is intended to cover the uncertainty in the cost estimate itself, whereas the process contingency covers the uncertainty in the technical development level of specific equipment. In both cases the contingencies represent costs that are expected to occur.

3.5 TOTAL PLANT INVESTMENT (TPI)

The TPI at date of start-up includes escalation of construction costs and allowance for funds used during construction, formerly called interest during construction, over the construction period. TPI is computed from the TPC, which is expressed on an "overnight" or instantaneous construction basis. For the construction cash flow, a uniform expenditure rate was assumed, with all expenditures taking place at the end of the year. The construction period is estimated to be 3 years. Given TPC, cash flow assumptions, nominal interest, and escalation
rates, TPI was calculated using:

$$TPI = TPC[1 + i] [t]$$

where

i = Weighted cost of capital, 5.0%
t = Average construction period or 3.0 years ÷ 2 = 1.5

3.6 TOTAL CAPITAL REQUIREMENT (TCR)

The TCR includes all capital necessary to complete the entire project. TCR consists of TPI, prepaid royalties, pre-production (or start-up) costs, inventory capital, initial chemical and catalyst charge, and land cost:

- Royalties costs are assumed inapplicable to the mature PFB plant and thus are not included.
- Pre-production Costs are intended to cover operator training, equipment checkout, major changes in plant equipment, extra maintenance, and inefficient use of fuel and other materials during plant start-up. They are estimated as follows:
  - 1 month of fixed operating costs--operating and maintenance labor, administrative and support labor, and maintenance materials.

  - 1 month of variable operating costs at full capacity (excluding fuel)-- includes chemicals, water, and other consumables and waste disposal charges.
  - 25 percent of full capacity fuel cost for 1 month--covers inefficient operation that occurs during the start-up period.
  - 2 percent of TPI--covers expected changes and modifications to equipment that will be needed to bring the plant up to full capacity.
- Inventory capital is the value of inventories of fuel, other consumables, and by-products, which are capitalized and included in the inventory capital account. The inventory capital is estimated as follows: Fuel inventory is based on full-capacity operation for 15 days. Inventory of other consumables (excluding water) is normally based on full-capacity operation for the same number of days as specified for the fuel. In addition, an allowance of ½ percent of the TPC equipment cost is included for spare parts.
- Initial catalyst and chemical charge covers the initial cost of any catalyst or chemicals that are contained in the process equipment (but not in storage, which is covered in inventory capital). No value is shown because costs are minimal and included directly in the component equipment capital cost.
- Land cost is based on 200 acres of land, as estimated from the plot plan drawing, at $10,000 per acre.

Each of the TCR cost components, as well as the summary TPC components and the TPI, is shown separately in Table 3.10.2 expressed in $1000 and $/kW (net).

3.7 CAPITAL COST ESTIMATE EXCLUSIONS

Although the estimate is intended to represent a complete PFB plant, there remain several qualifications/exclusions as follows:

- Sales tax is not included (considered to be exempt).
- On-site fuel transportation equipment is not included (i.e., barge tug, barges, yard locomotive, bulldozers).
- Allowances for unusual site conditions, such as piling, extensive site access, excessive dewatering, extensive inclement weather, are not included.
- Switchyard (transmission plant) is not included. The costed scope terminates at the high side of the main power transformer.
- Ash disposal facility is excluded, other than the 3-day storage in the ash-storage silos (the ash disposal cost is accounted for in the ash disposal charge as part of consumables costs; refer to Section 3.3.3).
- Royalties.

3.8 ESTIMATE ACCOUNT CONSISTENCY AND ACCURACY

Even though significant attention was directed at maintaining consistent and reasonable costing approaches for estimating the PFB plant components and systems, supplementary comparisons seemed advisable to verify the estimate. This PFB design study includes comparison of results to a conventional PC-fired plant (Section 5.5).

3.9 OPERATING COSTS AND EXPENSES

The operating costs and related maintenance expenses described in this section pertain to those charges associated with operating and maintaining the baseline plant over its expected life.

The costs and expenses associated with operating and maintaining the plant include:

- Operating labor
- Maintenance
  - Material
  - Labor
- Administrative and support labor
- Consumables
- By-product credit (if applicable)
- Fuel cost

The values for these items were determined consistent with EPRI TAG methodology. These costs and expenses are estimated on a first-year basis, January 2002 dollars. The first-year costs assume normal operation and do not include the initial start-up costs, which were computed separately (see Section 3.6). A 10-year levelizing factor is applied to these first-year costs and expenses to arrive at appropriate values that contribute to the total COE.

The operating labor, maintenance material and labor, and other labor-related costs are combined and then divided into two components: fixed O&M, which is independent of power generation, and variable O&M, which is proportional to power generation. The first-year operating and maintenance cost estimate allocation is based on the plant capacity factor.

The other operating costs, consumables and fuel, are determined on a daily 100 percent operating capacity basis and adjusted to an annual plant operation basis, equivalent to operating at 100 percent load for 80 percent of the year (plant capacity factor).

The development of the actual values was performed on a Parsons model that is consistent with TAG. The inputs for each category of operating costs and expenses are identified in the succeeding subsections along with more specific discussion of the evaluation processes. The results of these evaluations are included in Table 3.10.2 expressed on a first-year basis in terms of absolute cost and unit cost, either as mills/kWh or $/kW•yr, and on an equivalent levelized basis.

3.9.1 Operating Labor

The cost of operating labor was estimated on the basis of the number of operating jobs (OJ) required to operate the plant (on an average-per-shift basis). The operating labor charge (OLC) expressed in first year $/kW was then computed using the average labor rates:

$$\text{OLC} = \frac{\text{(OJ) x (labor rate x labor burden) x (8760 h/yr)}}{\text{(net capacity of plant at full load in kW)}}$$

Table 3.9.1.1 indicates the number of operating jobs, the operating labor rate, and the operating labor burden that were used to determine the first-year operating labor cost. The operating labor requirements were determined on the basis of in-house representative data for the major plant sections (e.g., coal handling, steam turbine plant). These data were supplemented by estimates of the manpower required for the carbonizer, PCFB, and HGCU sections to arrive at total plant operating requirements.

3.9.2 Maintenance

Since the development of the maintenance labor and maintenance material costs are so interrelated in this methodology, their cost bases are discussed together. Annual maintenance costs, according to EPRI methodology [ES-2], are estimated as a percentage of the installed capital cost. The percentage varies widely, depending on the nature of the processing conditions and the type of design.

Table 3.9.1.1 Baseline Plant Operating Labor Requirements

Operating Labor Rate (Base):	27.50 $/h
Operating Labor Burden:	30% of base
Labor Overhead Charge Rate:	25% of labor
Operating Labor Requirements (Operating Jobs) per shift:	
Category	Total Plant
Skilled Operator	3.0
Operator	19.0
Foreman	1.0
Laboratory Technicians, etc.	3.0
Total Operating Jobs	26.0

On the basis of engineering judgement, Parsons in-house data, and EPRI guidelines for determining maintenance costs, representative values expressed as a percentage of system cost were specified for each major system. The rates were applied against individual estimate accounts and are summarized by major system in Table 3.9.2.1. Using the corresponding TPC values, a total annual (first-year) maintenance cost was calculated, including both material and labor components.

Since the maintenance costs are expressed as maintenance labor and maintenance materials, a maintenance labor/materials ratio of 40:60 was used for this breakdown. The operating costs, excluding consumable operating costs, are further divided into fixed and variable components. Fixed costs are essentially independent of capacity factor and are expressed in \$/kW•yr. Variable costs are incremental, directly proportional to the amount of power produced, and expressed in mills/kWh. Separation of operating costs into fixed and variable components was based on the assumption that the portion of the operating cost that is fixed is proportional to the expected nominal capacity factor for the plant. The balance of the cost is expressed as a variable component. The assumption is predicated on EPRI guidelines and other utility experience that indicates that base-loaded plants tend to have a relatively high fixed component of the operating cost, whereas peaking and intermediate plants have high variable components that correlate with the capacity factor. The equations for these calculations are:

$$\text{Fixed O\&M} = \text{Capacity Factor (CF)} \times \text{Total O\&M } (\$/\text{kW}\bullet\text{yr})$$

$$\text{Variable O\&M} = [(1-\text{CF}) \times \text{Total O\&M } (\$/\text{kW}\bullet\text{yr}) \times 1000 \text{ mills}/\$]/(\text{CF} \times 8760 \text{ h/yr})$$

The administrative and support labor cost is the only O&M overhead charge included in the cost studies. It is a charge for administrative and support labor, which is taken as 25% of the operating and maintenance labor. General and administrative expenses are not included.

Table 3.9.2.1 - Baseline Plant Maintenance Factors

Item/Description	**Maintenance Percent**
COAL AND SORBENT HANDLING	2.6
Coal and Sorbent Prep and Feed	3.1
Feedwater and Miscellaneous BOP Systems	1.9
CARBONIZER AND PCFB BOILER	
Carbonizer	5.0
PCFB Boiler	4.5
Other PCFB Equipment	1.8
Hot Gas Cleanup and Piping	6.7
COMBUSTION TURBINE/ACCESSORIES	
Combustion Turbine Generator	3.5
Combustion Turbine Accessories	1.4
HRU, DUCTING AND STACK	
HRU	2.0
HRU Accessories	1.4
STEAM TURBINE GENERATOR	
Steam Turbine Generator and Accessories	1.5
Turbine Plant Auxiliaries	1.8
Cooling Water System	1.6
Ash/Spent Sorbent Handling System	3.2
Accessory Electric Plant	1.5
Instrumentation and Control	1.7
Improvements to Site	1.3
Buildings and Structures	1.4

3.9.3 Consumables

The feedstock and disposal costs are those consumable expenses associated with baseline plant operation. Consumable operating costs are developed on a first-year basis and subsequently levelized over the 30-year life of the plan. The consumables category consists of water, chemicals, other consumables, and waste disposal. The quantities and unit costs that were used to develop the corresponding cost values are indicated in Table 3.9.3.1 and examined separately.

The "water" component pertains to the water acquisition charge for water required for the plant steam cycle, miscellaneous services, and the ash pugmills.

Table 3.9.3.1 Baseline Plant Consumables

Item/Description	**Initial**	**Consumption/ Day**	**Unit Cost $**
Water, 1000 gal	---	4,060	0.80
Chemicals			
Water Treatment, lb	---	9,825	0.16
Other	---		
Dolomite, ton	24,000	946	16.50
Secondary Fuel, gal	250,000	1,000	0.75
Gases, N_2, etc., /100 sft^3	75,000	3,425	0.29
Waste Disposal			
PCFB Ash Disposal, ton	---	1,180	10.00
Fuel, ton	---	3,269	31.37

The "other consumables" component consists of fuel oil and gases. The fuel oil quantity accounts for coal drying, PCFB and carbonizer start-up heaters and miscellaneous use plus fuel for the auxiliary boiler. The gases category is primarily for the nitrogen required for transport and blanketing. The unit cost for gases was based on pricing furnished by an industrial gas supplier.

The "waste disposal" component pertains to the cost allowance for off-site disposal of plant solid wastes. The 1,180 t/d represents the total ash generated by the baseline plant and its unit cost for disposal is based on an adjusted EPRI value.

3.9.4 By-Product Credit

Although the ash from the PFB baseline plant can potentially be used for road construction, structural fill, agricultural fertilizing, etc., the economics of such uses would be highly site dependent. As a result no credit was taken for the potential sale of the ash from the PFB baseline plant.

3.9.5 Fuel Cost

The coal/fuel cost (FC) was developed on the basis of the EPRI cost for delivered coal (FC) of $\$1.26/10^6$ Btu, the net plant heat rate (NPHR) of 7,105 Btu/kWh, and the coal HHV of 12,450 Btu/lb. For the coal as well as for all feedstock and disposal costs, the quantity per day in Table

3.9.3.1 represents the 100 percent capacity requirement, while the annual values indicated in Section 3.10 are adjusted for the designated 80 percent plant capacity factor. The calculation of first-year fuel cost is:

$$\text{Fuel t/d} = \frac{\text{NPHR x kW (plant new capacity) x 24 h/d}}{\text{HHV x 2000 lb/t}}$$

$$\text{Fuel Unit Cost (\$/t)} = \text{HHV x 2000 lb/t x FC/ } 10^6$$

$$\text{Fuel Cost (1}^{\text{st}}\text{ year)} = \text{Fuel (t/d) x Fuel Unit Cost (\$/t) x 365 d/yr x 0.80 (capacity factor)}$$

3.10 COST OF ELECTRICITY (COE)

The revenue requirement method of performing an economic analysis of a prospective power plant is widely used in the electric utility industry. This method permits the incorporation of the various dissimilar components for a potential new plant into a single value that can be compared with various alternatives. The revenue requirement figure-of-merit is the levelized (over plant life) coal pile-to-busbar cost of energy expressed in mills/kWh. The value, based on EPRI definitions and methodology, includes the TCR, which is represented in the levelized carrying charge (sometimes referred to as the fixed charges), 10 year levelized fixed and variable operating and maintenance costs, 10 year levelized consumables operating costs, and 10 year levelized fuel cost.

The basis for calculating capital investment and revenue requirements is given in Table 3.10.1. Table 3.10.1, the capital investment and revenue requirement summary, is the principal cost and economics output for this study. Key TPC values from Table 3.2.2 are combined with other significant costs, including operating costs, maintenance costs, consumables, and fuel cost, resulting in the levelized busbar COE.

The levelized carrying charge, applied to TCR, establishes the required revenues to cover return on equity, interest on debt, depreciation, income tax, property tax, and insurance. Levelizing factors are applied to the first-year fuel, O&M, and consumables costs to yield levelized costs over the life of the project. A long-term inflation rate of 2.0 percent per year was assumed in estimating the cost of capital and in estimating the life-cycle revenue requirements for other expenses (except that fuel was escalated at 1.0 percent per year).

To represent these varying revenue requirements for fixed and variable costs, a "levelized" value was computed using the "present worth" concept of money based on the assumptions shown in Table 3.10.1 and resulting in a levelized carrying charge of 12.0 percent and a levelizing factor of 1.28 for all other-than-coal costs and 1.10 for coal cost.

By combining costs, carrying charges, and levelizing factors, a levelized busbar COE for the 80% design capacity factor was calculated at 41.9 mills/kWh and reported in Table 3.10.2 along with the levelized constituent values. The format for this cost calculation is:

$$\text{Power Cost (COE)} = (\text{LCC} + \text{LFOM}) \times \frac{1000 \text{ mills/\$}}{\text{CF} \times 8760 \text{ h/yr}} + \text{LVOM} + \text{LCM} - \text{LB} + \text{LFC}$$

where

LCC = Levelized carrying charge, \$/kW•yr
LFOM = Levelized fixed O&M, \$/kW•yr
LVOM = Levelized variable O&M, mills/kWh
LCM = Levelized consumable, mills/kWh
LB = Levelized by-products (if any), mills/kWh
LFC = Levelized fueled costs, mills/kWh
CF = Plant capacity factor, %

Table 3.10.1 - Estimating Basis/Financial Criteria for Review Requirement Calculation

GENERAL DATA/CHARACTERISTICS				
Case Title:	2nd Generation PFB Baseline			
Unit Size:/Plant Size:	477.5	MWe		
Location:				
Fuel: Coal/Secondary				
Energy From Primary/Secondary Fuels		Btu/kWh		
Levelized Capacity Factor:	80	%		
Capital Cost Year Dollars:	2002	(January)		
Delivered Cost of Coal/Secondary	1.26	$/MMBtu		
Design/Construction Period:	3	years		
Plant Startup Date(year):	2005	(January)		
Land Area/Unit Cost	20	acre	$10,000	/acre
FINANCIAL CRITERIA				
Project Book Life:	15	years		
Book Salvage Value:	0.0	%		
Project Tax Life:	20	years		
Tax Depreciation Method:	Straight Line			
Property Tax Rate:	1.0	% per year		
Insurance Tax Rate:	1.0	% per year		
Federal Income Tax Rate:	0.27	%		
State Income Tax Rate:	1.0	%		
Investment Tax Credit/% Eligible	None	%		
	% of Total		Cost(%)	
Capital Structure				
Common Equity	10		15.0	
Tax Free Municipal Bonds	0		0.0	
Debt	90		7.0	
Weighted Cost of Capital:(after tax)			7.8	%
Escalation Rates(Apparent)				
General Escalation:	2.5	% per year		
Coal/Secondary Fuel Price Escalation:	0.5	% per year		

Table 3.10.2 – Baseline Plant Capital Investment and Revenue Requirement Summary

TABLE 3.10.2. CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY				
TITLE/DEFINITION				7/15/03
Case:	2nd Generation PFB Baseline			
Plant Size:	477.5 (MW,net)	HeatRate:	7,105	(Btu/kWh)
Fuel(type):	0	Cost:	1.26	($/MMBtu)
Design/Construction:	4 (years)	BookLife:	30	(years)
TPC(Plant Cost) Year:	2002 (January)	TPI Year:	2005	(Jan.)
Capacity Factor:	80 (%)			
CAPITAL INVESTMENT		$x1000		$/kW
Process Capital & Facilities		388,671		814.0
Engineering(incl.C.M.,H.O.& Fee)		34,980		73.3
Process Contingency		29,983		62.8
Project Contingency		63,548		133.1
TOTAL PLANT COST(TPC)		517,182		1,083.1
TOTAL CASH EXPENDED	$517,182			
AFDC	38,789			
TOTAL PLANT INVESTMENT(TPI)		555,971		1,164.3
Royalty Allowance		0		0.0
Preproduction Costs		14,590		30.6
Inventory Capital		4,252		8.9
Initial Catalyst & Chemicals(w/equip.)		0		0.0
Land Cost		200		0.4
TOTAL CAPITAL REQUIREMENT(TCR)		$575,013		1,204.2
OPERATING & MAINTENANCE COSTS(First Year)		$x1000		$/kW-yr
Operating Labor		6,692		14.0
Maintenance Labor		4,918		10.3
Maintenance Material		7,376		15.4
Administrative & Support Labor		2,008		4.2
TOTAL OPERATION & MAINTENANCE(1st yr.)		$20,994		44.0
FIXED O & M (1st yr.)			35.17	$/kW-yr
VARIABLE O & M (1st yr.)			1.25	mills/kWh
CONSUMABLE OPERATING COSTS(First Year less Fuel)		$x1000		mills/kWh
Water		1,056		0.32
Chemicals		459		0.14
Other Consumables		5,069		1.51
Waste Disposal		3,446		1.03
TOTAL CONSUMABLES(1st yr.,-fuel)		$10,030		3.00
BY-PRODUCT CREDITS(First Year)		$0		0.00
FUEL COST(First Year)		$29,957		8.95
LEVELIZED (10 Year) OPERATION & MAINTENANCE COSTS				
Fixed O & M	45.0 $/kW-yr		6.4	mills/kWh
Variable O & M			1.6	mills/kWh
Consumables		1.280	3.8	mills/kWh
By-product Credit			0.0	mills/kWh
Fuel			9.4	mills/kWh
LEVELIZED CARRYING CHARGES(Capital)	144.5 $/kW-yr		20.6	mills/kWh
LEVELIZED (10 Year) BUSBAR COST OF POWER			41.9	mills/kWh
30 Years at a Capacity Factor of:	80%			

Section 4

ENVIRONMENTAL IMPACT

4.1 SUMMARY

The environmental impact of the 2nd Gen PFB baseline plant described in Section 2 and located in southwestern Pennsylvania along the Ohio River is addressed below. General siting requirements are based on Federal and Commonwealth of Pennsylvania regulations. Because a generic site is the basis for this study, site-specific aspects of a typical environmental assessment cannot be provided.

Table 4.1.1 identifies the baseline plant effluents and Table 4.1.2 compares its stack gas emissions to those allowed under New Source Performance Standards (NSPS). With the baseline plant producing 477.5 MWe net power with a 3,392 million Btu per hour heat input it is noted that stack gas emissions are well below NSPS allowables. The plant operates with 97.1% sulfur capture efficiency whereas NSPS requires only 87.1%. Similarly NOx is 1.2 versus 1.6 pounds per hour per MWe.

The stack gas particulate emission is 10 pounds per hour, which equates to 0.003 pounds per million Btu of heat release, again, well below the NSPS allowable of 0.03. In Section 5.6 the baseline plant emissions are compared to a conventional PC plant.

Table 4.1.1 Baseline Plant Effluents

Stack Emissions		
SO_2, lb/hr	461	(0.136 lb/10^6 Btu)
NOx, lb/hr	581	(1.2 lb/hr/MWe)
Particulate, lb/hr	10	(0.003 lb/10^6 Btu)
Solid Waste, lb/h	98,172	
Water Effluents, gal/d		
Coal Pile Runoff	30,000	
Dolomite Pile Runoff	4,000	
Cooling Tower Blowdown	1,440,000	
Boiler Blowdown	21,000	
Miscellaneous	12,000	

Table 4.1.2 Comparison of NSPS and Baseline Plant Stack Emissions

	Regulatory Standard	2^{nd} Generation PFB Baseline Plant Emissions
Uncontrolled SO_2, lb/10^6 Btu		
Above 12.0	1.2 lb/10^6 Btu	
6.0 to 12.0	90% Capture	
At 4.64	87.1% Capture	97.1%
2.0 and below	70% Capture	
NOx, lb/hr/MWe	1.6	1.2
Particulates, lb/10^6 Btu	0.03	0.003

Most Federal emission regulations are indexed on Btu heat input. There are, however, many state and local regulations that consider tons of pollutant emitted per year within a geographical area. In those locations 2^{nd} Generation PFB technology becomes even more attractive because of its high efficiency i.e. more power can be produced per ton of pollutant emitted. The following sections present the results of a conceptual analysis of the environmental impact of the baseline plant and it is concluded that the 2^{nd} Generation PFB baseline has a similar but to a lesser effect on air quality, geology, hydrology, water quality, land use, cultural resources, vegetation, wildlife, aquatic ecology, and other components of a proposed site as a conventional PC plant.

4.2 AIR EMISSIONS

In the discussions that follow, the 2^{nd} Gen PFB baseline plant burns 2.89 percent sulfur 12,450 Btu/lb HHV coal at a rate of 272,406 lb/hr along with dolomite and produces 477.5 MW net output with an efficiency of 48.0 percent.

4.2.1 Sulfur Dioxide

Regulatory Standards. The SO_2 regulatory standards for a combustion facility in the Commonwealth of Pennsylvania are guided by the Environmental Protection Agency (EPA) and the Standards for Stationary Sources, NSPS. The EPA has given Pennsylvania the authority to enforce NSPS.

If uncontrolled SO_2 emissions are 6 lb/10^6 Btu or higher, NSPS mandates 90% sulfur capture but the emission can not exceed 1.2 lb/10^6 Btu. If uncontrolled SO_2 emissions are less than or equal to 2 lb/10^6 Btu, a 70 percent sulfur capture efficiency is required. Between these two points there is a sliding scale for capture defined by:

$$\text{Required sulfur capture}=100(1-1.2/\text{uncontrolled } SO_2 \text{ in lb}/10^6 \text{ Btu})$$

Assuming that the southwestern Pennsylvania area is an attainment area, a Prevention of Significant Deterioration (PSD) application must be completed and filed with the Pennsylvania Department of Environmental Resources. This application will identify $S0_2$ as a major pollutant (greater than 40 t/yr) requiring a PSD evaluation, including Best Available Control Technology and a computer dispersion analysis of the stack emissions.

The ambient concentration standards for SO_2 are 80 $\mu g/m^3$ (0.03 ppm) annually, 365 $\mu g/m^3$ (0.14 ppm) maximum within 24 hours, and 1300 $\mu g/m^3$ (0.5 ppm) maximum within 3 hours. The PSD evaluation would need to show that these standards are neither violated nor approached, (concentration within 90 percent of the standard).

Plant Emission Rates. The 2nd Generation PFB baseline plant, uses dolomite in the carbonizer and PCFB boiler to reduce SO_2 emissions by 97.1 percent bettering the NSPS requirements for this coal.

The NSPS requirement for SO_2 emissions is 87.1 percent capture, which equates to 0.6 $lb/10^6$ Btu.

SO_2 emissions are controlled by adjusting the dolomite to coal feed ratio and the plant operates with a 1.75 calcium to sulfur molar feed ratio. Even though the baseline plant provides a large design margin below the standard further reduction is possible. The bulk of the stack SO_2 emission originates from the carbonizer which operates with 96.5 percent sulfur capture efficiency compared with 99 percent for the PCFB boiler. Emathelite is injected into the carbonizer syngas upstream of the candle filter to capture alkali vapors that would be corrosive to the gas turbine. If further SO_2 reduction were desired, powdered zinc oxide could be injected along with the emathelite; the zinc oxide would act as a polishing step and increase the carbonizer sulfur capture efficiency to 99 percent for an overall plant capture efficiency of 99 percent. This would increase capital and operating costs.

Impact Analysis. Using an 80 percent capacity factor, stack emissions of SO_2 from the baseline plant total approximately 4.4 t/d. Dispersion of stack $S0_2$ emissions needs further analyses by computer to determine the level of ambient concentration. However, with the assumed conditions of location and terrain, a computer analysis would probably show a low impact that would not endanger the ambient standards.

4.2.2 Mercury and Carbon Dioxide

Mercury (Hg) and carbon dioxide (CO_2) emissions have not been included in this analysis as there were no regulatory standards governing their release when this study was performed. If 90 percent Hg and CO_2 removal should become a requirement, the baseline plant will require processing steps to control their release; 2nd Gen PFB Combustion Plants, however, are in the unique position of being able to incorporate controls either upstream of the gas turbine where gas volumes are minimal or downstream of the gas turbine where gas pressures are reduced. Some aspects of mercury and CO_2 controls are discussed in Sections 5.6.1 and 6.6.

4.2.3 Nitrogen Oxides

Regulatory Standards. Pennsylvania has also been given authority by the EPA to enforce the NSPS for NOx. For a new source in Pennsylvania, the NSPS limit for NOx is 1.60 lb/MWh output.

Ambient standards for NOx are 100 μg/m3 (0.05 ppm). Computer dispersion analyses would be required to show the predicted ambient concentration and that the standard is not violated. In addition, a PSD application, including computer dispersion analysis, would be required for emissions of over 40 t/yr.

Plant Emission Rates. The PCFB boiler and the gas turbine topping combustor contribute to the stack NOx emission. Since the baseline plant is designed for peak efficiency, it operates with high excess air which yields a 50 percent excess air level in the PCFB boiler. Even though the PCFB boiler utilizes staged combustion to control NOx formation, it generates the bulk of the stack NOx. Under these conditions the stack NOx emission would be 581 lb/hr, which equates to 0.17 lb/10^6 Btu or 1.22 lb/hr/MWe. NOx output is thus 5.6 t/day, average, at an 80 percent capacity factor.

Impact Analysis. NOx emissions from the baseline plant are about 25 percent less than that permitted by NSPS. Although the impact of the NOx stack emissions from the baseline plant needs to be analyzed by computer modeling, it is expected that it would be within ambient standards.

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4.2.3 Particulates

Regulatory Standards. Particulate standards under NSPS for a new source in Pennsylvania are 0.03 lb/10 Btu input. Primary and secondary ambient standards for particulates PM_{10} are 50 μg/m3 annual geometric mean, and 150 μg/m3 maximum in 24 hours. An emissions rate exceeding 25 t/yr would require a computer dispersion analysis and a PSD application.

Plant Emissions Rates. The candle filters used by the baseline plant provide near total filtration with particle collection efficiencies as high as 99.999 percent having been measured at the Wilsonville Power Systems Development Facility [ES-7]. The baseline plant emission analysis assumes a 99.99 percent collection efficiency which yields a stack particulate flow of 10 lb/hr or 0.003 lb/10^6 Btu which well below the NSPS 0.03 lb/10^6 Btu limit or 102 lb/hr.

Impact Analysis. The emissions rate of 10 lb/h amounts to 240 lb/d or 44 t/yr (35 t/yr at 80 percent capacity factor), requiring a PSD computer dispersion analysis (over 25 t/yr) for impact on ambient standards

4.3 SOLID WASTES

4.3.1 Characteristics

Spent bed material and particulate captured by the ceramic candle filters are the two major sources of solid waste streams from the baseline plant. The amount of waste generated is a function of fuel and sorbent characteristics as well as the level of SO_2 and particulate control. Based on design parameters previously presented, the baseline plant will produce approximately 49 t/h solid waste. Approximately 345,000 t/yr would be generated at the expected 80 percent capacity factor.

Primary constituents of the solid waste streams are shown in Table 4.3.1.1. Coal ash and $CaSO_4$ make up over 60% of the solid waste production.

4.3.2 Regulatory Aspects

Solid waste disposal and any leachate generated by the plant are regulated by both Federal and State agencies. Applicable Federal regulations include those under the Resource Conservation Recovery Act (RCRA) and the National Pollutant Discharge Elimination System. In Pennsylvania, solid waste disposal is regulated by both the latter, which is part of the Clean Streams Law, and the Solid Waste Management Act.

Table 4.3.1.1 Baseline Plant Ash Constituents and Production Estimates

Constituents	lb/h
Coal ash	27,561
MgO	16,663
$CaCO_3$	19,683
Sorbent Inerts	1,364
$CaSO_4$	33,098
Total	98,369

Power generation wastes are specifically excluded from Federal regulations (Subtitle D of RCRA); however, concentrations of eight RCRA elements (arsenic, barium, cadmium, chromium, lead, mercury, selenium, and silver) in the leachate from the PFB combustion plant solid waste could result in the by-products being classified as hazardous. Based on recent research, using the U.S. EPA extraction procedure, all the by-products are well below levels at which they would be classified toxic under RCRA regulations. Barium, selenium, and chromium were present in the highest concentrations. Trace elements are discussed in detail in the following sections. Other components of the leachate, which may be of concern in certain circumstances, are pH, calcium, total dissolved solids, and sulfate.

Lime based sorbents injected into circulating fluidized bed boilers operating at atmospheric pressure calcine and result in free lime in the ash. Upon contact with water this lime can hydrate to form calcium hydroxide and a level of heat release that can represent an occupational rather than an environmental regulatory concern. Since the PCFB boiler operates at elevated pressure, the high partial pressure of carbon dioxide in the flue gas prevents the lime based sorbent's calcium carbonate from calcining. As a result Table 4.3.1.1 shows the unused sorbent remaining as calcium carbonate and this potential heat release is not a concern.

4.3.3 Disposal

As a non-hazardous material, PFB combustion plant wastes may be disposed of in a landfill and solid waste permits will be required for the disposal site. Handling, transportation, and disposal are similar to those for conventional PC plants with dry scrubbers. If water is added to the solid waste and the material is compacted, the permeability will be reduced, and the need for a liner to control leachate may be eliminated.

Based on an 80 percent capacity factor and a bulk density of 80 lb/ft^3, approximately 200 acre-ft/yr are required for landfill disposal of all ash. For the 30-year life of the plant, 6000 acre-ft are required.

4.3.4 Ash Utilization

An alternative to disposal of PFB combustion plant solid waste is commercial utilization. Several applications have been studied: concrete/road construction, agriculture, industry, and mining.

Preliminary results indicate that fluidized bed combustion spent bed material can be used as a no-cement concrete for mine subsidence and ventilation control, base construction for roadways, and conventional concrete/standard concrete masonry construction. Fluidized bed combustion plant ash has also been used in brick making in the United Kingdom.

Various experiments indicate that spent bed material is an effective material for liming agricultural areas, when applied at 10 to 50 t/acre. Spent bed material neutralizes acidic soil and supplements trace metals required for plant growth and has also been used to treat industrial and municipal wastes.

4.4 TRACE ELEMENT RELEASE AND TOXICITY

As with all coals and lime based sorbents the Pittsburgh # 8 coal and dolomite used by the baseline plant contain a small amount of trace elements. During the partial gasification and combustion steps used by the plant, a portion of these elements have the potential for release to the environment. An estimate of this release, based on literature searches and analytical estimates, was made for the original baseline plant and is contained in [ES-1]. In the absence of experimental data/measurements that estimate remains reasonable; it is felt that 2nd Gen PFB plant trace element releases will be significantly less than PC-fired plants and in all probability will be similar to those of plants incorporating coal-fired, atmospheric pressure, circulating fluidized bed boilers.

SECTION 5

COMPARISON WITH CONVENTIONAL PULVERIZED-COAL-FIRED PLANT

Pertinent features of the 2nd Generation PFB baseline plant and a comparable conventional pulverized coal-fired (PC) plant are compared in this section. Specifically, plant arrangement, performance, construction characteristics, reliability, economics, and environmental characteristics are compared. The PC plant selected for comparison has a slightly higher net output than the PFB baseline plant (506 MWe versus 477.5 MWe); the PC plant incorporates an electrostatic precipitator (ESP), a wet flue gas desulfurization system (FGD), and low NOx burners together with Selective Catalytic Reduction (SCR) to control emissions of particulate, sulfur dioxide, and nitrogen oxides respectively. The PFB baseline plant operates with a 97 percent sulfur capture efficiency and a NOx emission rate of 1.22 lbs per megawatt of net power produced. To permit an "apples to apples" comparison of the two plants, the PC plant scrubber was sized for the same 97 percent sulfur removal efficiency and the SCR sized for a nominal 60 percent NOx reduction to yield the same NOx emission rate. Because the PFB baseline plant operates with a significantly higher efficiency and incorporates ceramic filters for particulate control, the PFB baseline plant emissions are, with the exception of NOx, significantly lower than those of the PC plant. When emission rates are based on the megawatts of net power produced, and as shown in Section 5.6, the PFB baseline plant:

a.) SO_2 emissions are 19 percent lower
b.) NOx emissions are the same as the PC plant with low NOx burners and SCR
c.) particulate emissions are 92 percent lower
d.) CO_2 emissions are 17 to 19 percent lower

5.1 Plant Arrangement

Plant arrangements are a result of imposed site conditions, technology requirements, plant access logistics, and utility preference. There is not a major difference between either type of plant with regard to overall arrangement, since most of the area required for the plant is for the coal pile, coal delivery/conveying systems, electrical substation, cooling towers, parking, access roadways, etc. The power island, where the primary differences in plant arrangements occur, is only 4 percent (approximately) of the total plant area; thus a difference in this area is not significant as far as land use is concerned.

5.2 Plant Site Arrangement

The site plan for the PFB baseline plant (Figure 2.3.2.1) is presented in Section 2; the PC plant site plan is shown in Figure 5.1.1.1. Coal is unloaded, stored, and reclaimed in a similar manner for both plants. However, coal delivery is by barge in the baseline PFB plant, and rail in the PC plant. Dolomite and coal in the baseline PFB plant share coal unloading equipment; in the PC plant, limestone is delivered by rail and stored in an open pile.

The PFB main power block structures occupy about 15 percent less area relative to the PC plant; the overall site area for the PFB baseline plant is approximately 200 acres whereas the PC plant occupies about 250 acres. Both figures represent area within the plant security fence. The PFB baseline plant thus has a somewhat smaller footprint than the PC plant.

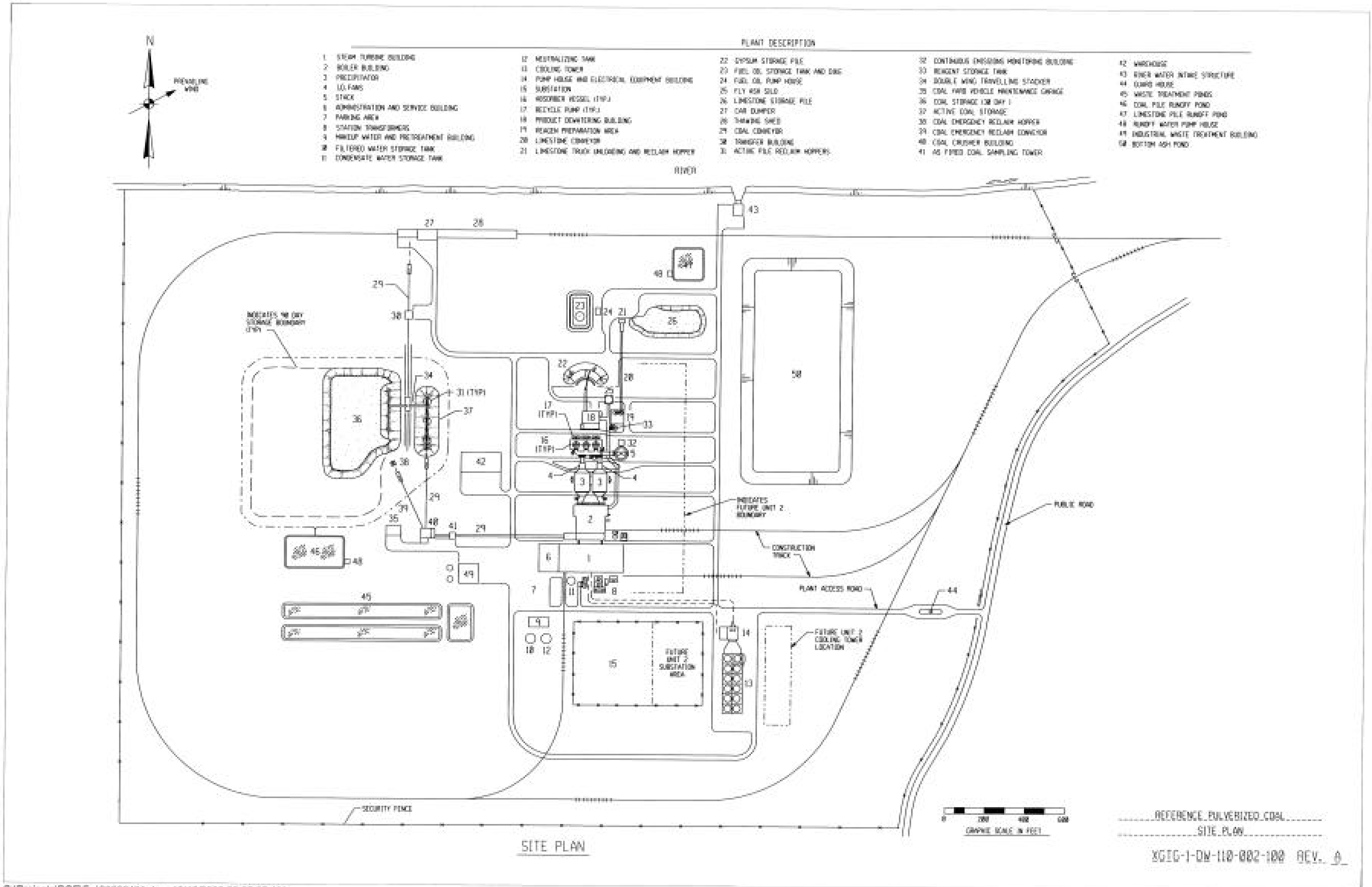

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Figure 5.1.1.1 PC Plant Site Plan

5.1.2 Power Island Comparison

Table 5.1.2.1 compares some key power island components. Although the comparisons do not address all interrelationships between components, shared duty, and auxiliary equipment required by each plant, a general conclusion can be drawn that the two plant power islands are nearly equivalent.

The PFB baseline plant, however, has a slight edge; its layout is more compact, primarily because of the requirement for a scrubber in the PC plant.

5.1.3 Coal/Sorbent Storage

As shown in Table 5.1.2.1 and when the PC plant values are scaled down to the same 477.5 MWe output, the PC plant coal and sorbent storage areas reduce to 458,000 and 47,000 square feet respectively. The PFB baseline plant coal storage area is 21 percent smaller than that of the PC plant whereas the sorbent area is about 112 percent larger. The difference in coal storage is due to the efficiency advantage of the PFB baseline plant. The need for a larger sorbent storage area for the PFB baseline plant is attributed to its use of dolomite rather than limestone for sulfur capture and its need to operate with a higher calcium to sulfur molar feed ratio (1.75 versus 1.1) for the same 97 percent sulfur capture efficiency. Based on total feedstock storage area, however, the PFB baseline plant requires about 9 percent less area.

From a sulfur capture standpoint a 2nd Generation PFB plant can operate equally well with either limestone or dolomite; to identify the performance and cost effects of these two different sorbents, dolomite was selected for the PFB baseline plant and limestone was selected for the Section 6.2 sensitivity study case. Since the dolomite used in this study is only 22% calcium by weight compared with 36 percent for the limestone, the sorbent area of the PFB baseline plant would be about 30 percent larger than the PC plant for the same output if both were to use limestone as their sorbents. Under this condition the PFB baseline plant would require about 12 percent less total feedstock storage area.

5.2 Performance

Table 5.2.0.1 compares the performance of the 477.5 MWe PFB baseline plant with that of the 506 MWe PC plant. The 48.0 percent efficiency of the PFB baseline plant is 9.1 percentage points or 23.4 percent higher than the 38.9 percent efficiency of the PC plant.

The PFB baseline plant produces 48 percent of its gross power with the gas turbine and 52 percent with the steam turbine; the PC plant produces all of its power from the steam turbine. Gross steam turbine/generator power for the PFB baseline plant is 48 percent of that of the PC plant gross power. Auxiliary losses are considerably lower for the PFB baseline plant. Its major auxiliary savings result from the elimination of forced- and induced-draft fans, elimination of wet scrubber losses, and reduction in cooling system pump and fan power because of the smaller steam cycle. The heat rate of the PFB baseline plant is 19 percent lower than that of the PC plant. When comparing actual flow rates, the PC plant values listed in Table 5.2.0.1 should be reduced by 5.6 percent to reflect a 477.5 MWe net output.

Table 5.1.2.1 Comparison of Power Island Component/System Sizes

Description	**PC Reference Plant**	**Second-Generation PFB Baseline Plant**	
Power Production, MWe			
Steam Turbine Output	547.4	259.0	
Gas Turbine Output	---	239.5	
Gross Plant Output	547.4	498.5	
Net Plant Output	506.0	477.5	
Building Areas, ft^2			
Steam Turbine Building	37,000	17,500	
Gas Turbine and PFB Building	---	32,000	
Boiler Building	30,600	0	
Other Buildings§	47,000	47,000	
Total Building Areas	114,600	96,500	
Other			
Height of Tallest Structure, ft	240	275	
Coal Storage Area (90 days), ft^2	485,000	360,000	Note 1
Sorbent Storage Area (90 days), ft^2	50,000	100,000 *	Note 1
Total Feedstock Storage, ft^2	535,000	460,000 *	
Total Storage Adjusted to 477.5 MWe, ft^2	505,000	460,000 *	

§ Administration, control, machine shop, maintenance, warehouse.

<u>Note 1</u> 90-day storage for the baseline PFB plant is for comparison only. The baseline PFB and PC plant layouts and costs include only 30-day coal and 35-day sorbent storage, in keeping with current business practice.

* these values reduce when limestone is used

Table 5.2.0.1 Performance Comparison of PC and PFB Baseline Plants

Description	Reference PC Plant	Second-Generation PFB Baseline Plant	Percent Change from PC
Overall Plant Performance:			
Gas Turbine Power, MW	---	239.5	---
Steam Turbine Power, MW	547.4	259.0	-47.3
Gross Power, MW	547.4	498.5	-8.9
Auxiliaries, incl transformer	41.4	22.7	-45.2
Net Power, MW	506.0	477.5	-4.5
Net Plant Efficiency,% (HHV)	38.9	48.0	+23.4
Net Plant Heat Rate Btu/kWh (HHV)	8,775	7,105	-19.0
As-Received Coal Feed, lb/h	356,650	272,406	-23.6
Other Feed, lb/h:			
Dolomite Feed	---	78,864 *	---
Limestone Feed	37,300	---	---
Acid (adipic) Feed	50	---	---
Ammonia Feed (SCR)	590	---	---
Total	37,940	78,864 *	107.9 *
Water Consumption, 10^3 gal/day:			
Cooling Tower Makeup	6,336	3,816	-39.8
Boiler Makeup/Miscellaneous	230	245	6.5
Flue Gas Desulfurization	792	---	---
Ash Pug Mill	---	144 *	---
Total Water Consumption	7,358	4,205 *	-42.9
Waste Products, lb/h:			
Ash and Spent Sorbent	34,600	98,369 *	---
Fixed Sludge	54,600	---	---
Total Solid Wastes	89,200	98,369 *	10.3 *

* these values reduce when limestone is used

Solid wastes produced by the PC plant consist of bottom and fly ash from the boiler and fixed sludge produced by the flue gas desulfurization system. All solid wastes from the PFB baseline plant are ash and spent sorbent. For the same output the PFB baseline plant generates about 17 percent more solid waste than the PC plant but, as seen in Section 6.2, when limestone is used as the sulfur sorbent the PFB plant waste flow is only about 1 percent larger than that of the PC plant.

5.3 Construction

The cost of erecting the PFB baseline plant is approximately 44 percent less than that of the PC plant, the savings being attributed to a much lower field labor cost. Although the construction activities of both plants are similar in many respects, there are several radically different areas that account for most of the variations in construction costs.

Areas of similarity occur primarily in the balance-of-plant category, involve approximately the same number of manhours, and consist of:

Site facilities

Yard work

Structures (excluding the steam generation module and boiler building)

Balance-of-plant systems

- Steam cycle equipment and subsystems
- Cooling water system
- Miscellaneous systems
- Accessory electric plant (equipment and bulk materials).

The most significant difference in plant construction manhours and costs is attributable to the erection of the PC plant boiler compared with the PFB baseline plant equivalent (e.g., the carnonizer and PCFB boiler island). The PC boiler erection effort involves in excess of one-half million labor manhours—a labor requirement dictated by the field assembly of the boiler package, including erection of boiler hangers, drum, waterwall panel assemblies, pressure piping, tube-bank assemblies, downcomers, and other interconnecting piping and headers; welding of all pressure-pipe connections; installation of burners; and assembly of air heaters, coal pulverizers, and many other components.

The PFB baseline plant effort essentially involves the rigging of a number of shop-fabricated and assembled components and the field erection of two major vessels, e.g., the carbonizer and the PCFB boiler. After erection and setting of the field-erected and shop-fabricated vessels, they are trimmed out. Piping and electrical scope is installed, followed by instrumentation, refractory lining, insulation, painting, etc.

The second area of major difference is in the construction/erection of gas clean up equipment. In the PC plant, this activity involves the field assembly of the ESP and FGD systems; the comparable PFB baseline plant efforts include the erection of shop-assembled cyclones and ceramic filter vessels (the latter do require field installation of their candle). Since the PFB baseline plant gas clean up equipment operates at high pressure, albeit at higher temperature, the net effect is that the volume of gas being cleaned in the PFB baseline plant is roughly one-twelfth that of the gas being cleaned in the PC plant. The volumes of the clean up devices involved are also very different because of the basic design and operating difference; for instance, the ESP is roughly 1,500,000 ft^3 in volume, while the eight ceramic filter vessels total less than 40,000 ft^3.

Another area of construction advantage for the PFB baseline plant is in the ash-handling system. Although the ash-handling system in the PFB baseline plant is larger, the cost of erection labor is lower than that of PC plant because the latter must have both wet and dry ash systems. The PFB baseline plant relies only on dry pneumatic systems for the collection and transport of fly ash and bottom ash. The PC plant utilizes multiple wet systems, e.g., a boiler bottom ash grinding and sluicing system and hydro-bin systems for dewatering boiler bottom ash and FGD spent reagent.

The construction of steel structures is essentially the same for both plants except for the steam-generation module of the PFB baseline plant and the boiler/steam turbine building of the PC plant. The PC plant boiler building has about twice the volume. In addition, the PC boiler is hung from the top of a structure incorporated in the building structure; the baseline plant components are bottom supported at a much lower elevation, outside the turbine building. Hence, the PC-fired plant boiler building requires considerably more structural steel. In addition, a significantly smaller portion of the baseline plant structure is enclosed. These factors result in the need for a substantially larger field labor crew to complete the PC plant, even though construction methods are similar in both cases. Another significant difference between the two plants is the degree of equipment setting that is accomplished in conjunction with the erection of structural steel. In the PC plant, the frame setting of such components as the deaerator, feedwater heaters, and secondary air heaters is coordinated with main building steel erection. For the baseline plant, all major component rigging will most likely be coordinated with steel erection in the steam-generation module area.

An area of plant erection that appears at first to favor the PC plant is the erection of the electricity-generating equipment. The PC plant scope consists of one 547 MWe steam turbine/generator and accessories, whereas the baseline plant consists of one 259 MWe steam turbine/generator package, one 240 MWe gas turbine/generator package, and one gas turbine exhaust heat recovery unit. The PC plant turbine/generator is field-erected, including installation of upper and lower casings, rotors, bearings and seals, shells, crossover pipe, steam chests, stop throttle valves, intercept and stop valves, generator, exciter, E-H control system, gland seal system, and hydrogen cooling system plus accessories. Because the turbine/generator in the PFB baseline plant is smaller, it is more modular and requires less manpower for erection. The gas turbine is also modular; it is assembled from few major shipping modules that need much less field assembly work than the PC plant turbine/generator. The gas turbine modules involved are: (1) the combustion turbine assembly (compressor section, combustion system, and power turbine), (2) the generator and exciter module, and (3) auxiliary equipment, consisting of the starting package assembly, the electrical/ control package assembly, the air-to-air cooler assembly, and the mechanical package assembly. In addition, the heat recovery unit is constructed from major shop-assembled shipping modules designed to minimize field erection. Even though the PFB baseline plant generation components consist of three major elements, compared with one element for the PC plant, their extensive shop assembly and shipping in modules makes the total PFB baseline plant erection effort similar to that of the PC plant turbine/generator erection effort. The PC plant cooling water systems and cooling tower are approximately one and one-half times the size of those in the baseline plant. When erection of the entire plant is considered, the baseline plant has an advantage – a significant reduction in labor hours compared to the PC plant.

Using present day modularity techniques a nominal 500 MWe PC plant can be erected in as little as 36 months. The labor hours needed to erect the PFB baseline plant, with its extensive use of shop fabricated components (only the carbonizer and PCFB boiler require field assembly), are approximately half that of the PC plant. Because fewer labor hours are required it can be expected the baseline PFB plant could be constructed in a shorter period of time. To confirm such an expectation, however, would require preparation of a detailed construction schedule which was beyond the scope of this study. Since a new technology is involved and to insure a conservative economic analysis, a 36-month construction schedule has also been assumed for the baseline PFB plant

5.4 Reliability and Availability Assessment Comparison

As discussed in Section 2.8, a RAM analysis was prepared in 1987 for a 2nd Generation PFB baseline plant; the study concluded that upon reaching technology maturity (an “Nth” plant) the reliability/availability of the PFB baseline plant should be similar to that of a conventional PC plant with FGD. In the absence of actual 2nd Generation PFB plant operating data, the referenced study remains a reasonable assessment of PFB baseline plant capabilities.

5.5 Cost/Economic Comparisons

The costs of the PFB baseline plant are presented and discussed in Section 3. In Table 5.5.0.1, the capital investment and revenue requirements of each of these plants are summarized to facilitate a comparison of these two different technologies. The comparisons presented in the table follow the order of the Section 3 PFB baseline plant cost development; since the electrical output of the two plants is not exactly the same (i.e., 477.5 vs. 506 MWe), unit cost relationships ($/kW) are not in exactly the same ratio as absolute costs. Table 5.5.0.2 presents operating costs and economics for the two plants.

Table 5.5.0.1 Capital Investment Comparison of PC and PFB Baseline Plants

	PFB Baseline Plant		**PC Plant**		**Percent Change from PC Plant**	
	Plant Size:	477.5 MW (net)	Plant Size:	506.0 MW (net)	-5.6%	
	Fuel:	Pittsburgh #8	Fuel:	Pittsburgh #8	---	
	Design/ Construction:	3.5 years	Design/ Construction	3.5 years	0%	
	TPC (Plant Cost) Year:	2002 (Dec.)	TPC (Plant Cost) Year:	2002 (Dec.)	---	
	Capacity Factor:	80%	Capacity Factor:	80%	---	
	Heat Rate:	7105 Btu/kWh	Heat Rate:	8775 Btu/kWh	-19.0%	
	Cost:	1.26 $\$/10^6$ Btu	Cost:	1.26 $\$/10^6$ Btu	---	
	Book Life:	30 years	Book Life:	30 years	---	
	TPI Year:	2003 (Jan.)	TPI Year:	2003 (Jan.)	---	
Description	**$ x 1000**	**$/kW**	**$ x 1000**	**$/kW**	**$ Basis (%)**	**$/kW Basis (%)**
Capital Investment:						
Process Capital and Facilities	388,671	814.0	485,142	958.8	-20	-15
Engineering (including Construction Management, Home Office, and Fee)	34,980	73.3	43,663	86.3	-20	-15
Process Contingency	29,983	62.8	0	0	---	---
Project Contingency	63,548	133.1	79,321	156.8	-15	-22
Total Plant Cost (TPC)	517,181	1,083.1	608,126	1,201.8	-15	-10
Total Plant Investment (TPI)	555,971	1,164.3	653,735	1,292.0	-15	-10
Royalty Allowance	---	---	---	---	---	---
Preproduction Costs	14,590	30.6	15,367	30.4	-5	-1
Inventory Capital	4,232	8.9	6,383	12.6	-34	-29
Initial Catalyst and Chemicals (with equipment)	---	---	7,200	14.2	---	---
Land Cost	200	0.4	250	0.5	-20	-19
Total Capital Req't (TCR)	574,993	1,204.2	682,935	1,349.7	-16	-11

Table 5.5.0.2 Operating Cost and COE Comparison of PC and PFB Baseline Plants

Description	PFB Baseline Plant	PC Plant	Percent Change from PC Plant	
			$ Basis (%)	$/kW Basis (%)
O&M Costs (1st year):				
Operating Labor, $ x 1000	6,692	6,692	0	6
Maintenance Labor, $ x 1000	4,918	4,953	-1	5
Maintenance Material, $ x 1000	7,376	7,430	-1	5
Administrative and Support Labor, $ x 1000	2,008	2,008	0	6
Total O&M Costs (1st year), $ x 1000	20,994	21,084	0	6
Fixed Operating and Maintenance (1st year), $/kW-yr	35.17	33.33	---	6
Variable Operating and Maintenance (1st year), mills/kW	1.25	1.19	---	5
Consumable Operating Costs (1st year less fuel):				
Water, $ x 1000	1,056	1,719	-39	-35
Chemicals, $ x 1000	459	3,674	-88	-87
Other Consumables, $ x 1000	5,069	2,634	92	104
Waste Disposal, $ x 1000	3,446	3,126	10	17
Total Consumables (1st year less fuel), $ x 1000	10,030	11,152	-9	-9
By-Product Credits (1st year)	---	---	---	
Fuel Cost (1st year), $ x 1000	29,957	39,207	-24	-19
				mills/kWh basis
Levelized O&M Costs:				
Fixed Operating and Maintenance, mills/kWh	6.4	6.1		5
Variable Operating and Maintenance, mills/kWh	1.6	1.5		7
Consumables, mills/kWh	3.8	4.0		-5
By-Product Credit, kWh	---	---		---
Fuel, mills/kWh	9.4	11.6		-19
Levelized Carrying Charges (Capital), mills/kWh	20.6	23.1		-11
Levelized Busbar Cost of Electricity, mills/kWh	41.9	46.4		-10

5.5.1 Capital Investment

The capital cost estimate of the 506 MWe PC plant is based on recent Parsons studies and experience. The Total Plant Cost (TPC) estimate is $608,211,000 or $1,202/kW in 2002 dollars. A comparison between the 477.5 MWe PFB baseline plant and the 506 MWe PC plant on a major account basis is shown in Table 5.5.1.1. At this level the PFB baseline plant is $91.0 million less or $119/kW less (10 percent below the PC plant). All comparisons are made on both a total dollar basis as well as an adjusted basis because the PC plant net output is 6 percent higher.

Because of the technology differences, all accounts are not directly comparable. However, some major comparisons can be made. The largest difference comes from the Account 5 gas clean up systems where the PC plant cost is $218/kW versus $124/kW for the PFB baseline plant; a cost savings of $94/kW for the PFB baseline plant. This is primarily due to the PC plant requirement for an FGD system for 97% SO_2 removal. The PFB plant does not require any add-on systems for 97 percent SO_2 removal.

By combining Accounts 6, 8, and 9 it is possible to compare the turbine/generator and cooling water systems. The combined PC plant costs are $240/kW versus the PFB baseline plant costs of $303/kW; a cost savings of $63/kW for the PC plant.

A comparison between the buildings and structures accounts is not possible since the costs of the boiler building and combustion/turbine building are not compatible. However, the PC plant requires a much larger building for the boiler than the PFB baseline plant requires for the gas turbine. Variations in other accounts are as expected but are not as significant as those referenced above.

The PFB baseline plant cost estimate contains a $30 million (or 6 percent of total) process contingency allowance because the plant is based on new technology (in actuality it is slightly higher because in the cost roll up it is subjected to engineering and project contingency charges). No process contingency is included in the PC plant cost estimate as it is based on mature technology. The overall project contingency at 15 percent of Bare Erected Costs and Engineering is the same for both plants.

Engineering, Construction Management and Other Professional fees were calculated at 9 percent of the bare erected costs for both plants. Because the PC plant is slightly larger and more costly, the associated engineering costs are larger ($44 million versus $35 million).

5.5.2 Total Plant Investment (TPI)

Table 5.5.0.1 shows a further comparison of costs beyond the TPC level. The overall comparison does not change significantly between the two plants. The Total Plant Investment (TPI) line includes AFUDC costs (financing during construction). The schedule for overall plant design and construction are similar at 3-1/2 years each and financing interest rates are also similar. Therefore, the estimated totals are proportional.

5.5.3 Total Capital Requirement (TCR)

Added to the TPI are Royalty Allowances, Preproduction Allowances, Inventory Capital (for Spares), Initial Catalyst, and Land Cost to produce the Total Capital Required (TCR). Only minor differences are observed including a need for 20 percent more land for the PC plant. The PFB baseline plant is still about 10 percent lower than the 506 MWe PC plant on a $/kW basis.

5.5.4 Operating and Maintenance Costs

The PFB baseline plant is estimated to require about the same number of operators per shift as the PC plant. Maintenance costs were determined for each cost account as a percentage of their total equipment costs and divided into a 40/60 labor to material ratio. Where the PFB baseline plant incorporated new technologies and, in the absence of historical data, higher percentages were used (see Table 3.9.2.1 for actual values used). The fixed and variable operating and maintenance costs shown in Table 5.5.0.2 reflect the operating and maintenance relationships described in Section 3 and show the PFB baseline plant to be about 5 percent higher than the PC plant on a $/kW basis.

5.5.5 Consumable Operating Costs

Consumable operating costs for both the PFB baseline plant and the PC plant are identified in Table 5.5.5.1 and include:

Makeup water required for the cooling tower, FGD system (PC plant), steam cycle, and several consumptive items in the PFB plant (carbonizer steam, carbonizer syngas quench, and ash pug mill). The evaporative cooling towers that serve as the main plant heat sink for both plants is the largest consumer of makeup water, accounting for close to 90 percent of water consumption in each plant. The PFB baseline plant water consumption is observed to be 44 percent less than the PC plant.

Chemicals required for each plant include those used for water treating. The PC plant also uses adipic acid to control pH in the wet FGD system and ammonia and catalyst in conjunction with the SCR NOx reduction system. The PFB baseline plant requires 44 percent less water treatment chemicals and does not require adipic acid, ammonia, or SCR catalyst.

A category noted as “Other Consumables” includes sorbent (dolomite for the PFB plant and limestone for the PC plant), secondary fuels (oil or gas) for startup, and plant gases (nitrogen, carbon dioxide, and hydrogen). Because of its use of dolomite, the PFB baseline plant sorbent flow rate is 111 percent larger than that of the PC plant whereas other items in this category are similar.

A waste disposal category includes costs for disposing of ash from the PFB and PC plants and dewatered FGD sludge from the latter. Because of the use of dolomite, the PFB baseline plant waste flow is about 10 percent larger than that of the PC plant.

Assuming an 80 percent capacity factor, the PFB baseline plant requires a total expenditure for consumables of $10,030,000/yr versus $11,152,000/yr for the PC plant; when corrected for net output the PFB plant consumable cost is approximately 5 percent lower on a $/kW basis or 4 percent lower on a mills/kWh basis. When the PFB plant operates with limestone rather than dolomite, sorbent and ash disposal costs decrease significantly and the PFB baseline plant consumables cost advantage, both on a $/kW and mills/kWh basis both increase to 33 percent.

Table 5.5.1.1 Comparison of PFB Baseline and PC Plant Total Plant Costs (Year 2002 $ x 1000)

Acc't		**477.5 MWe Baseline**		**506 MWe PC Plant**		**Difference From PC Plant**		
No.	**Item / Description**	**$**	**$/kW**	**$**	**$/kW**	**$**	**$/kW**	**%**
1	Coal & Sorbent Handling	$22,730	$48	$23,857	$47	-$1,127	$0	1%
2	Coal & Sorbent Prep & Feed	$36,786	$77	$18,953	$37	$17,833	$40	106%
3	Feedwater & Misc BOP Systems	$25,489	$53	$37,817	$75	-$12,328	-$21	-29%
4	Carbonizer & PCFB Boiler Islands	$100,502	$210	$118,361	$234	-$17,860	-$23	-10%
5	Hot Gas Cleanup & Piping	$59,120	$124	$110,199	$218	-$51,079	-$94	-43%
6	Combustion / Turbine & Accessories	$76,775	$161	$0	$0	$76,775	$161	#DIV/0!
7	HRU, Ducting, & Stack	$28,867	$60	$28,877	$57	-$10	$3	6%
8	Steam Turbine Generator	$48,517	$102	$90,256	$178	-$41,739	-$77	-43%
9	Cooling Water System	$19,093	$40	$31,189	$62	-$12,095	-$22	-35%
10	Ash/Spent Sorbent Handling Sys	$25,358	$53	$28,913	$57	-$3,555	-$4	-7%
11	Accessory Electric Plant	$27,733	$58	$32,617	$64	-$4,883	-$6	-10%
12	Instrumentation & Controls	$20,542	$43	$18,410	$36	$2,132	$7	18%
13	Improvements to Site	$10,891	$23	$11,242	$22	-$352	$1	3%
14	Buildings & Structures	$14,779	$31	$57,520	$114	-$42,741	-$83	-73%
	Total Plant Cost	$517,182	$1,083	$608,211	$1,202	-$91,029	-$119	-10%

Table 5.5.5.1 Consumables Cost Comparison at 80% Capacity Factor

Item / Description	477.5 MWe Baseline PFB		506 MWe PC Plant		Difference from PC Plant		
	$ x 1,000	**Mills/kWh**	**$ x 1,000**	**Mills/kWh**	**$ x 1,000**	**Mills/kWh**	**%**
WATER	**$1,056**	**0.32**	**$1,719**	**0.48**	**-$663**	**-0.16**	**-34%**
4.06 mg/d x 365 x 0.8 x $800/mg/d*			7.3 mg/d x 365 x 0.8 x $800/mg/d				
Chemicals							
Water Treatment	**$459**	**0.14**	**$825**	**0.23**	**-$366**	**-0.09**	**-40%**
9,825 lb/day x $0.16 x 365 x 0.8*			17,666 lb/day x $0.16 x 365 x 0.8				
Adipic Acid	**$0**	**0.00**	**$263**	**0.07**	**-$263**	**-0.07**	**-100%**
None			350,000 lb/yr x $0.75/lb				
Ammonia	**$0**	**0.00**	**186**	**0.05**	**-$186**	**-0.05**	**-100%**
None			1,240 tons/yr x $150/ton				
SCR Catalyst	**$0**	**0.00**	**2,400**	**0.67**	**-$2,400**	**-0.67**	**-100%**
Subtotals	**$459**	**0.14**	**$3,674**	**1.03**	**-$3,215**	**-0.89**	**-86%**
Other							
Dolomite for PFB- Limestone for PC	**$4,560+**	**1.36**	**$2,157**	**0.61**	**$2,403**	**0.76**	**125%**
78,864 lb/h / 2,000 lb/ton x 24 h/day x $16.50/ton x 365 x 0.8*			37,300 lb/h / 2,000 lb/ton x 24 h/day x $16.50/ton x 365 x 0.8				
Secondary Fuels	**$219**	**0.07**	**$187**	**0.05**	**$32**	**0.01**	**25%**
1,000 gal/day x $0.75/gal x 365 x 0.8*			850 gal/day x $0.75/gal x 365 x 0.8				
Gases	**$290**	**0.09**	**$290**	**0.08**	**$0**	**0.01**	**6%**
3,425 cu ft/day x $0.29 x 365 x 0.8*			3,425 cu ft/day x $0.29 x 365 x 0.8				
Subtotals	**$5,069**	**1.51**	**$2,634**	**0.74**	**S2,435**	**0.77**	**105%**
Waste Disposal							
Ash	**$3,446+**	**1.03**	**$1,212**	**0.34**	**$2,233**	**0.69**	**202%**
98,369 lb/h / 2,000 lb/ton x 24 h/day x $10/ton x 365 x 0.8*			34,600 lb/h / 2,000 lb/ton x 24 h/day x $10/ton x 365 x 0.8				
Sludge	**$0**	**0.00**	**$1,913**	**0.54**	**-$1,913**	**-0.54**	**-100%**
			54,600 lb/h / 2,000 lb/ton x 24 h/day x $10/ton x 365 x 0.8				
Subtotals	**$3,446+**	**1.03**	**$3,126**	**0.88**	**$320**	**0.15**	**17%**
Totals	**$10,030+**	**3.00**	**11,152**	**3.13**	**-$1,122**	**-0.13**	**-4%**

*Baseline PFB Plant +These costs reduce significantly when limestone is used

5.5.6 Fuel Cost

The fuel cost component indicates a decided advantage for the PFB baseline plant at a 24% lower cost and a 19% lower $/kW cost. The unit cost advantage is directly correlated with the difference in net plant heat rate. The lower absolute cost is a function of both the lower heat rate and the slightly smaller plant.

5.5.7 Levelized COE Costs

The levelized component of COE values exhibits the same relationships as its first-year counterparts. Collectively, they amount to a 10% lower COE for the PFB baseline plant (41.9 vs. 46.4 mills/kWh).

5.6 Environmental Comparison with Conventional PC Plant

5.6.1 Air Emissions

The 1990 Clean Air Act Amendments motivated a major change in emissions control technologies and their applications. For the purposes of discussion in this report, the changes in emissions driven by the new regulations and technology applications are considered separately for each of three major criteria pollutants: SO_2, NOx, and particulates. When the emission rates for the two plants are based on a megawatt of net power produced, the PFB baseline plant emits approximately:

a.) 19 percent less SO_2
b.) 92 percent less particulate
c.) 17 to 19 percent less CO_2

Since the PC plant has been provided with both low NOx burners and an SCR to match the PFB baseline plant, their NOx emissions are the same. Very small particle, Hg, and CO2 controls were not evaluated in this comparison as there were no were officially promulgated regulations controlling their release when this work was performed. Several Hg and CO2 control processes aimed for installation on the "back end" of PC boilers are in the development/testing stage. A 2nd Gen PFB Combustion Plant is in the unique position of being able to incorporate control processes either upstream of the gas turbine where gas volumes are minimal or downstream of the gas turbine where pressures are close to ambient. CO2 control is an example of this and Section 6.6 shows the effect these two locations have on plant performance. Similarly, although, not evaluated, activated carbon could be used to control PFB baseline Hg emissions via a packed bed arrangement upstream of the gas turbine or by in duct powder injection into the gas turbine exhaust gas. Since candle filters remove all particulate matter upstream of the gas turbine the latter could be performed without contaminating the plant ash stream with used activated carbon.

Sulfur Dioxide. The 1990 Clean Air Act Amendments impose a limitation on stack gas SO_2 emissions including establishing a national cap on total SO_2 emissions and permitting the trading of allowances to accommodate individual plant over or under control of this pollutant. In addition to Federal law, states have enacted and enforce local ordinances pertaining to these emissions. As a practical matter, most new facilities being permitted in the current time frame are configured to remove above 90 percent of the SO_2. The PFB baseline plant and the PC plant were both designed for 97 percent removal and yield the comparison shown in Table 5.6.1.1.

Table 5.6.1.1 SO_2 Emission Comparison of PC and PFB Baseline Plants

Parameter	PC Plant	PC Plant	PFB Baseline
MWe Net	506	477.5	477.5
% Sulfur Capture	97	97	97
Btu/kWh, HHV	8,775	8,775	7,105
Heat Input, MMBtu/hr	4,440	4,190	3,392
SO2, lb/h	618	584	473
SO2, lb/MMBtu	0.139	0.139	0.139
SO2, lb/hr/MWe	1.22	1.22	0.99
SO2, t/yr*	2,165	2,044	1,657

*at 80% capacity factor

Oxides of Nitrogen. The permitting of electric generating plants with respect to oxides of nitrogen is more complex than for SO_2. The permitting process for NOx includes additional consideration for the effects of NOx as a precursor to the formation of ozone, which is recognized as a harmful pollutant at ground level. The U.S. EPA has designated a large region of the continental U.S. as an ozone transport region. Within the boundaries of this region, NOx emissions are more severely limited than outside the region. The so-called “Ozone Transport Region” encompasses a large part of the U.S. east of the Mississippi River.

The permitting process for NOx within the Ozone Transport Region involves a complex set of rules that effectively reduces allowable NOx emissions to very low levels. The actual emission rate that can be permitted varies with the technology selected for the power plant i.e. coal-fired steam plant, integrated coal gasification combined cycle plant, gas-fired combustion turbine plant, etc., as well as the local jurisdiction and their willingness for compromise.

The 477.5 MWe PFB baseline plant utilizes staged combustion in both the PCFB boiler and the gas turbine syngas combustor to yield a plant NOx emission rate of 581 lb/hr or 1.22 lb/MWe. The 506 MWe PC plant has been provided with low NOx burners and a 60.3% efficient SCR to yield the same 1.22 lb/MWe NOx emission rate and Table 5.6.1.2 compares the two plants.

Table 5.6.1.2 NOx Emission Comparison-PFB Baseline versus PC with Low NOx Burners and SCR

Parameter	PC Plant Controlled	PC Plant Controlled	PFB Baseline Uncontrolled
MWe net	506	477.5	477.5
Btu/kWh, HHV	8,775	8,775	7,105
Heat Input, MMBtu/hr	4,440	4,190	3,392
NOx, lb/h	616	581	581
Lb/MMBtu	0.14	0.14	0.17
Lb/hr/MWe	1.22	1.22	1.22
NOx, t/y*	2,158	2036	2036

*at 80% capacity factor

Particulate. The current state of the art for particulate removal in stack gases in a PC plant is based on two principal technologies e.g. electrostatic precipitators and bag filters. Both of these technologies are capable of removal rates for particulates of 99.9 percent or better, resulting in emissions rates of 0.03 lb/10^6 Btu. The PFB baseline plant utilizes a different type of particulate capture device, e.g., a ceramic barrier filter. These filters are capable of removal of at least 99.99 percent of the particulate matter in the gas path, resulting in emission rates of <0.003 lb/10^6 Btu. The plant comparisons are presented in Table 5.6.1.3 and reveal the PFB baseline plant emits 92 percent less particulate.

Table 5.6.1.3 Particulate Emission Comparison of PC and PFB Baseline Plants

Parameter	PC Plant	PC Plant	PFB Baseline
MWe Net	506	477.5	477.5
Btu/KWh HHV	8,175	8,175	7,105
Heat Input, MMBtu/hr	4,440	4,190	3,392
Lb/MMBtu	0.03	0.03	0.003
Particulate, lb/h	133.2	125.7	10.2
Lb/hr/MWe	0.263	0.263	0.021
Particulate, t/y*	467	440	35

*at 80% capacity factor

Carbon Dioxide. At the present time, emissions of carbon dioxide are not regulated. In addition, the U.S. withdrew its signed commitment to the Kyoto Accord, which called for limitations and reductions in emissions of CO_2 to the environment by the industrialized nations of the world. That said, it is still advantageous for a technology to demonstrate reduced emissions of CO_2, on an intensive (lb/10^6 Btu) and extensive (tons/year) basis, provided that the economics of deployment and use are not compromised. Since the PFB and PC plants operate with the same coal, their CO_2 emissions per million Btu of heat input are the same, save for differences in CO_2 released by their sulfur sorbents. Because of the high partial pressure of CO_2, calcium carbonate does not calcine when it is injected into the carbonizer and PCFB boiler; just like in FGD systems, CO_2 is only released from the sulfur capture reaction. Hence, when the PFB plant uses limestone as its sulfur capture sorbent, the CO_2 release rate per million BTU of heat input is the same as the PC plant. When dolomite is used as the PFB sorbent, the magnesium carbonate component does calcine and the PFB plant CO_2 release rate is increased slightly. Because the PFB plant operates with a much higher efficiency (48.0 versus 38.9 percent), the PFB plant CO_2 emission per megawatt of net power generated is 17 to 19 percent less than that of the PC plant (see Table 5.6.1.4).

Table 5.6.1.4 CO_2 Emission Comparison of PC and PFB Baseline Plants

Parameter	PC Plant	PC Plant	PFB Baseline (Dolomite)	PFB Baseline (Limestone)
MWe Net	506	477.5	477.5	477.5
Btu/KWh HHV	8,775	8,775	7,105	7,081
Heat Input, MMBtu/hr	4,440	4,190	3,392	3,380
CO2, lb/hr	920,474	868,629	721,614	700,918
CO2, lb/MMBtu	207.3	207.3	212.7	207.3
CO2, lb/MWe	1,819.1	1,819.1	1511.2	1,467.9
CO2, t/y*	3,225,341	3,043,677	2,528,535	2,456,017

*at 80% capacity factor

5.6.2 Solid Wastes

Solid waste produced by the PFB baseline plant fluidized bed systems differs from that produced by the PC plant FGD system. Fluidized bed combustion produces a dry solids residue; conventional FGD scrubbers produce liquid sludge, which is up to 35 percent liquid even after primary dewatering. Further dewatering yields a solid cake product that can be handled as a solid. Residues from fluidized bed combustion waste are primarily spent sorbent, unreacted sorbent, and fly ash. FGD sludge is primarily calcium sulfite with some calcium sulfate. The fluidized bed combustion residue can be blended for fixation/stabilization; FGD sludge has a tendency to re-liquefy. The quantity of solid waste produced by the PFB baseline plant operating with dolomite is about 17 percent larger than the fly ash and dewatered waste from the PC plant (Table 5.6.2.1). However the effect on the land may be considerably different if the FGD waste is removed to a pond or a landfill without treatment. In that case the PC plant would produce more waste than the PFB baseline plant operating with dolomite. Although PFB combustion wastes can be directly disposed of in a landfill with successful reclamation of the land, a pond receiving FGD waste must be committed for the operating life of the plant and beyond. When the PFB plant uses limestone as its sorbent the PC and PFB plant waste flow rates are essentially equal.

Table 5.6.2.1 Solid Waste Production Comparison at 477.5 MWe

Units	PC Plant (Limestone)	PFB Baseline (Dolomite)	PFB Baseline (Limestone)
lb/h	84,176	98,369	84,760
10^3 t/y *	295	345	297

*at 80% capacity factor

5.6.3 Water Effluents

In comparing the treated wastewater effluent from the PFB baseline and PC plants, the following assumptions were made for the latter:

- Bottom ash sluice wastewater is recycled through dewatering bins and a treatment system. The only discharge to the receiving stream is the blow down from the recycle system.

- The floor drain system includes sufficient capacity to collect bottom ash hopper seal water overflow.

- An SO_2 scrubber is included for treatment of flue gases.

Table 5.6.3.1 presents estimates of daily wastewater flow rates for typical waste sources for both the PFB baseline and PC plants. The total daily flow to be treated from the PC plant is about 70 percent larger than that from the PFB baseline plant. Table 5.6.3.2 compares waste effluents for specific discharge parameters and shows that the PC plant has a much greater impact on a receiving stream. The two factors that account for the difference in total daily discharge flows between the two units shown in Table 5.6.3.2 for water treatment, boiler blow down, cooling-tower blow down, and coal-pile runoff waste sources are:

- The PFB baseline plant is 9.1 percentage points higher in efficiency than the PC plant.

- Only 52 percent of the PFB baseline plant power is produced by the steam turbine whereas all the PC plant power is generated by the steam turbine.

Since the solid residue from the PFB baseline plant is handled in a dry state by cyclones, bag filters, and pneumatic handling equipment, there is no discharge of ash wastes to a receiving stream. The PC plant employs a wet, bottom ash hopper in which bottom ash is sluiced by high-capacity high-head pumps to mechanical dewatering bins. Although a recycle system reduces the total discharge to the receiving stream, a 72,000 gal/d blow down rate is still required. Floor drains and sumps in the PFB baseline plant receive equipment drains, cooling water, and wash down wastes only, which are estimated at 2000 gal/d. Similar flow rates are generated by the PC plant for the same sources; however the PC boiler requires a wet-seal trough to seal expanding boiler walls hung from above the unit. The boiler seal trough requires a continuous discharge flow rate of 2 to 4 gal/min/ft of boiler hopper perimeter for cooling. The continuous discharge is contaminated by ash, and approximately 500,000 gal/d ash hopper seal trough wastes require treatment. After removal of the particulate, this water is recycled in the plant and a small continuous blowdown maintains solids concentrations within control limits.

5.6.4 Trace Element Releases

As discussed in Section 4.4 there is no 2nd Generation PFB plant operating/test data available to permit a quantitative comparison of PFB baseline and PC plant trace element releases. It is felt, however, that the lower operating temperatures employed by the PFB baseline plant carbonizer and PCFB boiler will result in a lower, more benign release of coal trace elements. In addition it is expected that the PFB baseline plant trace element release will be similar to that of conventional atmospheric pressure fluidized bed boilers.

5.6.5 Noise

Although the PFB baseline plant has several unique aspects, conventional acoustical engineering practices should suffice, and the noise levels should be comparable to those from a PC plant.

Table 5.6.3.1 Comparison of Environmental Impact of Sources of Waste at 477.5 MWe (gal/d)

Waste Source	PC Plant	PFB Baseline	Comments
Ash Transport Water	90,000	---	Represents blow down from assumed recycle
Low-Volume Wastes			
Water Treatment	20,000	10,000	
Boiler Blowdown	39,000	21,000	
Floor Drains	4,000	2,000	
Ash-Hopper-Seal Water Blowdown	4,000	---	
Air Preheater Washes	4,000	---	Represents average; occurs once/year at 1.4 x 10^6 gal
Cooling Tower Blowdown	2,320,000	1,440,000	Based on 4 cycles of concentration, and no treatment for recycling of the blowdown
Material Storage Runoff			
Coal Pile Storage	30,000	30,000	
Dolomite Storage	4,000	4,000	
Total	2,515,000	1,507,000	

Table 5.6.3.2 Treated Waste Effluent Comparison at 477.5 MWe

	PC Plant		PFB Baseline	
Parameters	**mg/L**	**lb/d**	**mg/L**	**lb/d**
pH	6-9	---	6-9	---
Suspended Solids	30	618	30	260
Total Iron	4	83	4	35
Oil and Grease	15	309	15	130
Total Manganese	2	41	2	17

Section 6

SENSITIVITY STUDY

Since 2nd Generation PFB Combustion Plants are a new power generation technology, an analysis was undertaken to determine the sensitivity of its performance and economics to alternate design conditions and configurations. A total of eight cases were investigated; the first four investigated plant performance and economics whereas the balance only determined performance effects. The cases studied are described in the following sections, summarized in Table 6.8.1, and include the baseline plant:

Case	Description
1	operating with limestone rather than dolomite
2	operating with 16 foot rather than 10 foot diameter filter vessels
3	operating with metallic rather than ceramic candle filters
4	operating with limestone and 16 foot diameter filter vessels
5	operating with increased steam turbine power output
6	operating with CO_2 removal downstream of the gas turbine
7	operating with CO_2 removal upstream of the gas turbine
8	operating with a supercritical pressure steam turbine

6.1 LIMESTONE SULFUR SORBENT (CASE 1)

2nd Generation PFB Combustion Plants use lime based sorbents to capture sulfur released during the partial gasification and combustion of coal. The sorbent is fed together with the coal into the process and, in addition to being a sulfur capturing adsorbent, it becomes the bed material for both the carbonizer and the PCFB boiler. Both dolomite and limestone work equally well as sulfur sorbents but because their calcium contents differ, their use can yield different plant efficiencies and economics. To determine their effects, dolomite was used for the baseline plant and limestone was selected for the sensitivity investigation. Table 6.1.1 presents the composition of the limestone and, when compared to the dolomite given in Table 2.2.1.2, its calcium content per pound of sorbent is about 62 percent higher.

Table 6.1.1 Limestone Analysis (Percent by Weight)

CaCO3	90.10
MgCO3	1.42
Inerts*	8.48
	100.00

*Al_20_3, Fe_2O_3, TiO_2, Na_2O, K_2O, etc.

Since the limestone calcium content is significantly higher than that of the dolomite, sorbent feed rates and ash generation rates will be smaller and should result in increased plant efficiency. Figure 6.1.1 presents a mass and energy balance for the baseline plant operating with limestone rather than dolomite. Table 6.1.2 summarizes the performance and economics of the two plants and Table 6.1.3 identifies the auxiliary power draws of the limestone plant.

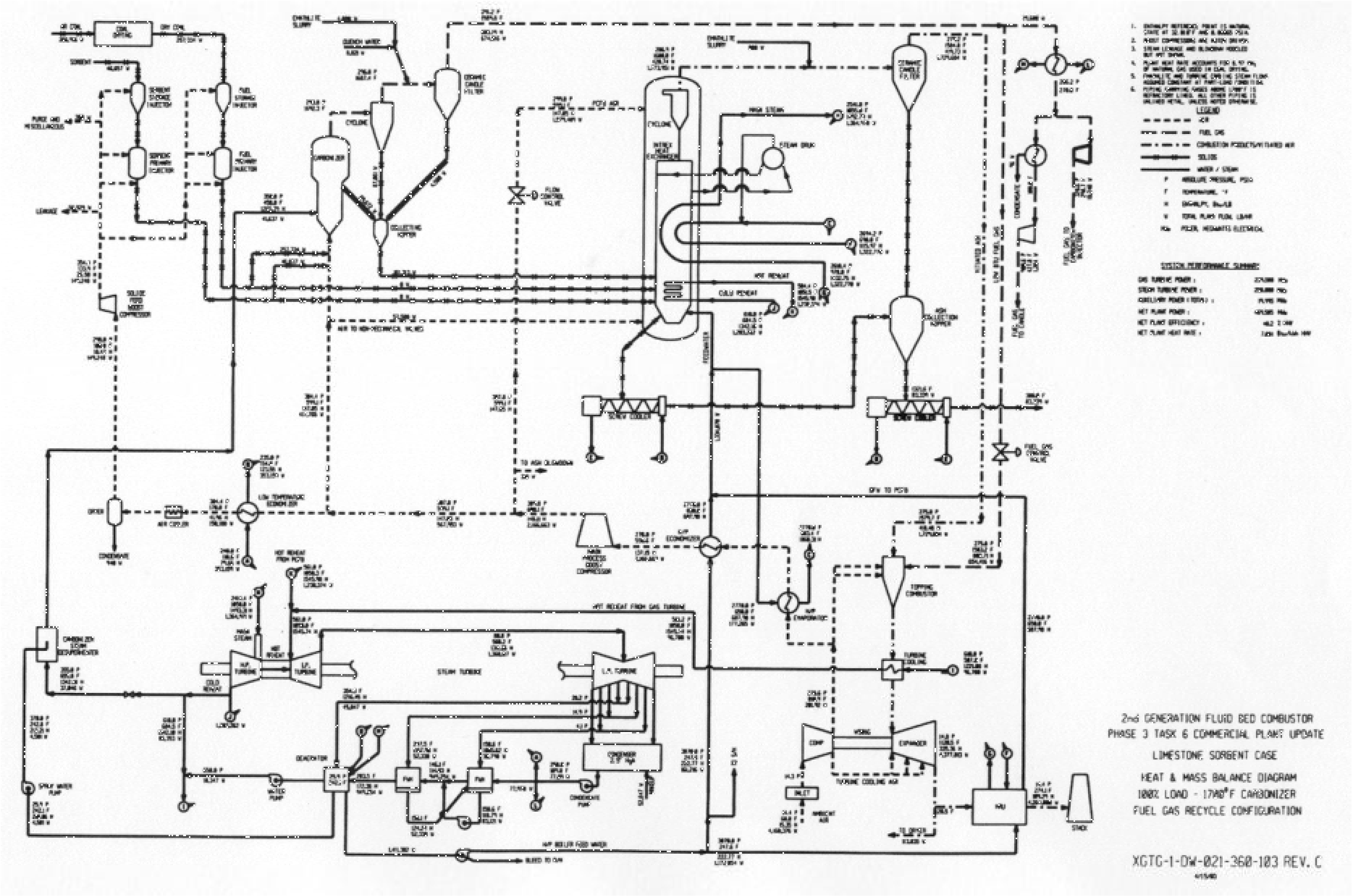

Figure 6.1.1 Limestone Case Plant Mass and Energy Balance

Table 6.1.2 Effects of Limestone Sorbent on Plant Performance and Economics

	Limestone Sorbent	Baseline
Overall Plant Performance		
Net Efficiency,% (HHV)	48.20	48.00
Net Heat Rate, Btu/kWh	7081.00	7105.00
Net Power, MWe	469.51	477.56
Auxiliaries, MWe	20.00	20.90
Gross Power, MWe	489.50	498.46
Coal Flow Rate, lb/hr	266,920	272,406
Sorbent Flow Rate, lb/hr	46,657	78,864
Ash Flow Rate, lb/hr	83,340	98,369
Gas Turbine Parameters		
Nominal Combustor Exit Temp, ^{0}F	2,700	2,700
Gross Power, MWe	239.50	239.50
Steam Turbine Parameters		
Steam Throttle Flow Rate, lb/hr	1,364,971	1,384,989
Reheat Steam Flow Rate, lb/hr	1,335,074	1,354,234
Condenser Total Duty, MMBtu/hr	1,270	1,270
Gross Power, MWe	250.00	258.96
Plant Economics		
Total Plant Costs, $/KW	1,085	1,083
Total Capital Requirement, $/KW	1,207	1,204
First Year Costs		
Total O&M, $/kW-yr	44.70	44.00
Fixed O&M, $/kW-yr	35.77	35.17
Variable O&M, mill/kWh	1.28	1.25
Consumables, mills/kWh	2.11	2.83
Fuel, mills/kWh	8.92	8.95
Levelized (10 yr) O&M, mills/kWh		
Fixed O&M	6.5	6.4
Variable O&M	1.6	1.6
Consumables	2.7	.3.8
Fuel	9.4	9.4
Levelized Carrying Charge, mills/kWh	20.7	20.6
Levelized Busbar Cost*, mills/kWh	40.9	41.9

* 30 years at 80%
capacity factor

Table 6.1.3 Auxiliary Load Summary for Plant Using Limestone Sorbent (kWe)

Main Boost Compressor	7,210
Transport Boost Compressor	380
Fuel Gas Recycle Blower	100
Condensate Pumps	380
Feedwater Pumps	4,000
Boiler Forced Circulation Pumps	315
Circulating Water Pumps	2,070
Cooling Tower Fans	1,550
Coal Dryer Induced Draft Fan	250
Gas Turbine Auxiliaries	300
Steam Turbine Auxiliaries	300
Nitrogen Supply	0
Barge Unloading and Stacker/Reclaimer	170
Coal Handling	350
Limestone Handling	70
Coal and Sorbent Feed	30
Ash Cooling and Handling	100
Filter Boost Compressor	350
Miscellaneous Balance of Plant (Note 1)	1,000
Transformer Loss	1,070
Total	19,995
Note 1 - Includes plant control systems, lighting, HVAC, etc.	

As expected, sorbent and ash flow rates per pound of coal fired are approximately 40 and 14 percent lower respectively and the plant efficiency is 0.2 percentage points higher than the dolomite based plant (48.2 versus 48.0 percent). The use of limestone reduces the costs of the feed and ash systems slightly but because the net plant output also decreased slightly the total plant costs are essentially the same ($1085 versus $1083/KW). Typically most of a sorbent's delivered cost is attributed to transportation and a $16.50 per ton cost has been assumed for both the limestone and dolomite used in this study. The use of limestone provides about a 29 percent reduction in the cost of consumables and yields about a 2 percent reduction in the cost of electricity (40.9 versus 41.7 mills/kWh).

6.2 Large (16 Foot Diameter) Filter Vessels (Case 2)

As discussed in Section 2.5.7 the baseline plant utilizes a total of 6,272 silicon carbide candles to remove entrained particulate from the carbonizer syngas and the PCFB boiler flue gas before they reach the gas turbine. The largest filter vessel built and operated at the time of this study was nominally 10 feet in diameter and contained 784 candles in a four-cluster array. To be conservative, it was decided to use this same vessel arrangement for the baseline plant. As a result, the baseline plant utilizes a total of eight nominally 10 feet diameter filter vessels. Alternate filter arrangements are possible and up to 1,568 candles can be placed inside of a nominal 16 foot diameter vessel in an eight cluster arrangement. Although such an arrangement would offer little difference in performance, it might offer a cost saving and so the economics of a four, large vessel filter arrangement, each with 1,568 candles in an eight-cluster array, was investigated. The two large carbonizer filter vessels were 15.2 feet in diameter by 54 feet tall whereas the two PCFB filter vessels were 15.6 feet in diameter by 58 feet tall. As with the small vessel arrangement, the large vessels were shop fabricated and rail shipped to the site. After setting vessel body sections in position, tubesheets, clusters, and candles were installed, clusters seal welded to the tubesheets, top heads bolted to the bodies, and interconnecting piping and pulse cleaning skids installed.

Since the number of clusters, candles, and method of installation are essentially identical in both vessel arrangements, the cost savings associated with the use of large vessels is somewhat mitigated. Despite this, the large vessel arrangement yielded a $3.1 million reduction in total plant costs; approximately 1/3 of this savings is attributed to the vessels themselves with the balance attributed to fewer vessels, less piping, less floor space, etc. The maintenance cost associated with the large vessels was assumed to be one percent less than that of the small vessels.

As expected, the use of four nominally 16 foot diameter rather than eight 10 foot diameter filter vessels provided a slight reduction in total plant costs; the larger filter vessel arrangement yielded a total plant cost of $1,077/KW and a cost of electricity of 41.7 mills per kilowatt hour compared with $1,083/KW and 41.9 mills/kWh for the small vessel arrangement.

6.3 Filters With Porous Metal Candles (Case 3)

To maximize the efficiency of the baseline plant the carbonizer syngas and the PCFB boiler flue gas are fired hot/enter the gas turbine combustor at approximately 1600°F. Because of the high temperature involved, the candles that are used to strip these gases of entrained particulate matter are made of silicon carbide. Silicon carbide candles are brittle, are susceptible to temperature shock, and have been known to break, hence, each candle has been provided with a fail safe device that will quickly form a dust seal in the event a candle breaks.

Porous metal candles made from sintered metal powders are also commercially available and can be provided with internal fail safes. Being metallic, they are more ductile and less susceptible to temperature shock failures than silicon carbide but corrosion and oxidation considerations limit them to lower operating temperatures. When furnished in iron aluminde, their manufacturer indicates they are suitable for both oxidizing and reducing atmospheres for temperatures approaching 1400ºF. By cooling the carbonizer syngas and the PCFB boiler flue gas the ceramic candles can be replaced by metal candles. The refractory lined piping with inner metallic liners that connect the filter vessels to the gas turbine can also be replaced by metallic piping.

A mass and energy balance for the baseline plant operating with metal filters is presented in Figure 6.3.1 and performance and economics are summarized in Tables 6.3.1 and 6.3.2. The carbonizer syngas is cooled from 1800ºF to 1000ºF via a fire-tube type cooler that generates 500ºF cold reheat steam. The PCFB boiler flue gas is cooled from 1600ºF to 1200ºF by passage over convective tube bundles that superheat steam to 1010ºF. With these gases having been cooled additional syngas is needed to maintain the 2700ºF gas turbine combustor outlet temperature. As a result, the carbonizer operating temperature and coal flow are increased by 100ºF and 7,104 lb/hr and respectively. The increased operating temperature increases the carbonizer carbon conversion/amount of coal energy converted into syngas and, despite the increase in coal flow, the char flow to the PCFB boiler decreases. The plant high pressure steam generation rate decreases whereas the reheat steam flow increases. Although the gas turbine power output is essentially unchanged, the steam turbine output decreases and the plant net efficiency decreases by 2.2 percentage points (45.8 versus 48.0 percent).

The nominal 2-3/8 inch diameter by 60 inch long silicon carbide candles were replaced by porous metal iron aluminide candles of the same overall dimensions. The 60 inch long metal candles consisted of three 18 inch long sections that were welded together via solid rings as well as to a cap on the bottom and to a flanged type end connection at the top; the latter facilitates connection to the tubesheet. With a metal candle costing more than three times that of a silicon carbide candle (approximately $1,500 versus $450), the cost of the filter system increased by approximately 30 percent. The syngas cooler, PCFB boiler flue gas cooler, and additional lengths of piping/expansion loops in the filter to gas turbine piping (piping now running at approximately 1000ºF and 1200ºF) also increased the plant costs. Since the metal candles are commercially proven, the process contingency was reduced from 20 to 10 percent. The net result was that the total plant costs increased by $7.992 million or 1.5 percent yielding values of $1,124/KW and 43.0 mills/kWh versus $1,083 and 41.9 mills/kWh for the ceramic filter plant.

The above metal filter analysis was based on a 60 inch candle length. Iron aluminide metal candles, however, are available in up to 96 inch lengths which, if used, might result in some cost reduction (the longer length was not investigated as it would have necessitated a redesign of the filter). In addition the metal candles are much thinner (nominally 1/16 versus 3/8 inch thick), lighter, and offer less flow resistance. If these additional factors were to be taken into consideration, it is believed a more detailed analysis would result in a somewhat smaller increase in plant costs.

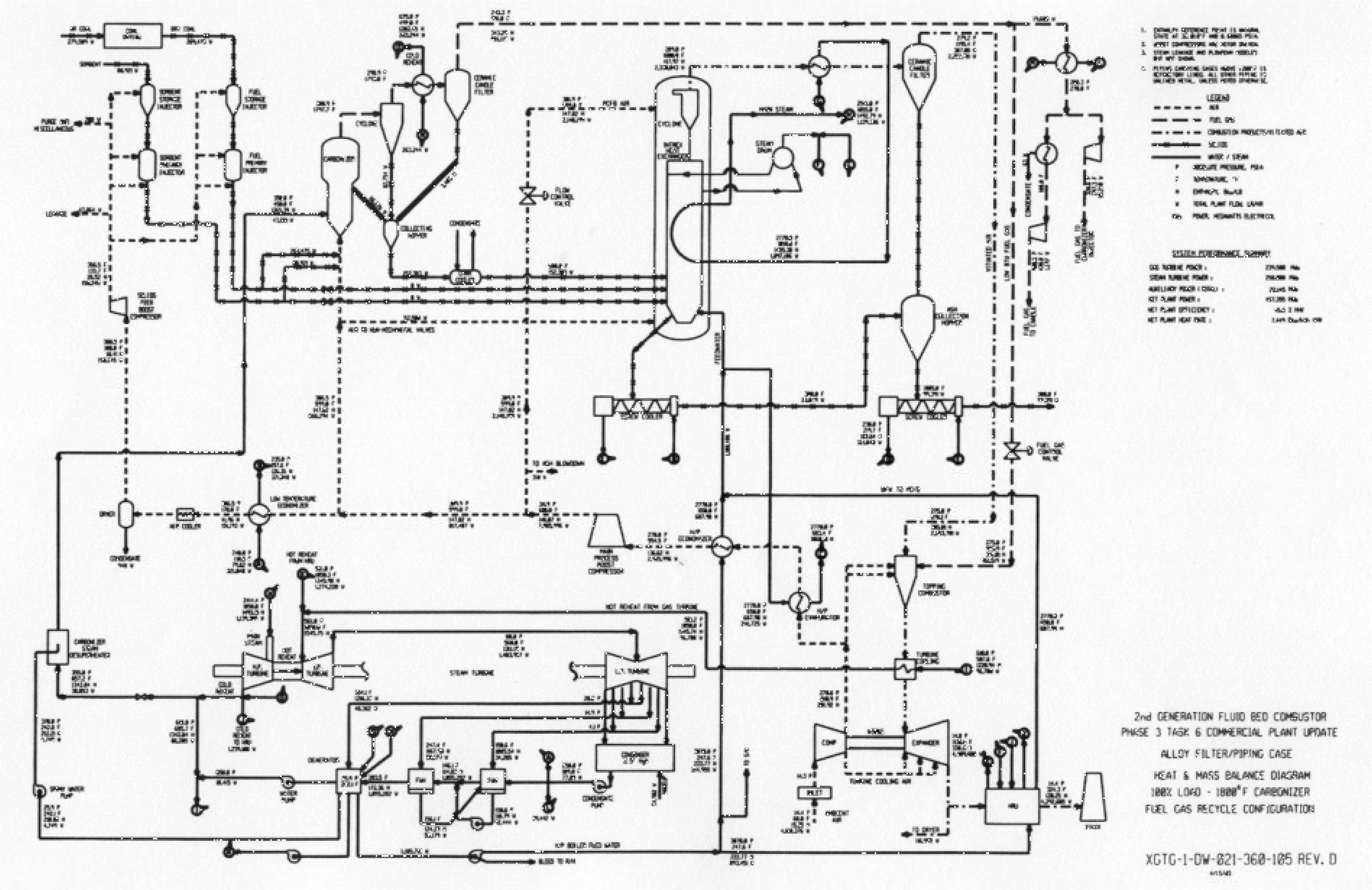

Figure 6.3.1 Metal Filter Case Plant Mass and Energy Balance

Table 6.3.1 Effect of Metal Candles on Plant Performance and Economics

	Metal Filter	Baseline
Overall Plant Performance		
Net Efficiency,% (HHV)	45.80	48.00
Net Heat Rate, Btu/kWh	7449.00	7105.00
Net Power, MWe	467.36	477.56
Auxiliaries, MWe	22.15	20.90
Gross Power, MWe	489.50	498.46
Coal Flow Rate, lb/hr	279,510	272,406
Dolomite Flow Rate, lb/hr	80,920	78,864
Ash Flow Rate, lb/hr	99,390	98,369
Gas Turbine Parameters		
Nominal Combustor Exit Temp, ^{0}F	2,700	2,700
Gross Power, MWe	239.50	239.50
Steam Turbine Parameters		
Steam Throttle Flow Rate, lb/hr	1,139,305	1,384,989
Reheat Flow Rate, lb/hr	1,370,920	1,354,234
Condenser Total Duty, MMBtu/hr	1,270	1,270
Gross Power, MWe	250.00	258.96
Plant Economics		
Total Plant Costs, $/KW	1,124	1,083
Total Capital Requirement, $/KW	1,249	1,204
First Year Costs		
Total O&M, $/kW-yr	42.40	44.00
Fixed O&M, $/kW-yr	33.90	35.17
Variable O&M, mill/kWh	1.21	1.25
Consumables, mills/kWh	3.10	3.00
Fuel, mills/kWh	9.39	8.95
Levelized (10 yr) O&M, mills/kWh		
Fixed O&M	6.2	6.4
Variable O&M	1.5	1.6
Consumables	4.0	3.8
Fuel	9.9	9.4
Levelized Carrying Charge, mills/kWh	21.4	20.6
Levelized Busbar Cost*, mills/kWh	43.0	41.9

* 30 years at 80%
capacity factor

Table 6.3.2 Metal Filter Auxiliary Load Summary (kWe)

Main Boost Compressor	9,950
Transport Boost Compressor	380
Fuel Gas Recycle Blower	100
Condensate Pumps	390
Feedwater Pumps	3,340
Boiler Forced Circulation Pumps	315
Circulating Water Pumps	2,080
Cooling Tower Fans	1,600
Coal Dryer Induced Draft Fan	250
Gas Turbine Auxiliaries	300
Steam Turbine Auxiliaries	300
Nitrogen Supply	0
Barge Unloading and Stacker/Reclaimer	170
Coal Handling	350
Dolomite Handling	70
Coal and Sorbent Feed	30
Ash Cooling and Handling	100
Filter Boost Compressor	350
Miscellaneous Balance of Plant (Note 1)	1,000
Transformer Loss	1,070
Total	22,145

Note 1 – Includes plant control systems, lighting, HVAC, etc.

6.4 Limestone and 16 Foot Diameter Filter Vessels (Case 4)

Since limestone increases the plant efficiency and a nominal 16 foot diameter filter vessel reduces plant costs, both were combined for study. The Figure 6.1.1 mass and energy balance and Table 6.1.3 auxiliary load summary remain applicable to this plant; Table 6.4.1 summarizes plant performance and economics and reveals an efficiency of 48.2 percent with improved economics; the total plant cost reduces to $1,079 with a cost of electricity of 40.7 mills/kWh.

Table 6.4.1 Effect of Limestone and Large Filter Vessels on Plant Performance and Economics

	Limestone and Large Filter Vessels	Baseline
Overall Plant Performance		
Net Efficiency,% (HHV)	48.20	48.00
Net Heat Rate, Btu/kWh	7081.00	7105.00
Net Power, MWe	469.51	477.56
Auxiliaries, MWe	20.00	20.90
Gross Power, MWe	489.50	498.46
Coal Flow Rate, lb/hr	266,920	272,406
Sorbent Flow Rate, lb/hr	46,657	78,864
Ash Flow Rate, lb/hr	83,340	98,369
Gas Turbine Parameters		
Nominal Combustor Exit Temp, ^{0}F	2,700	2,700
Gross Power, MWe	239.50	239.50
Steam Turbine Parameters		
Steam Throttle Flow Rate, lb/hr	1,364,971	1,384,989
Reheat Steam Flow Rate, lb/hr	1,335,074	1,354,234
Condenser Total Duty, MMBtu/hr	1,270	1,270
Gross Power, MWe	250.00	258.96
Plant Economics		
Total Plant Costs, $/KW	1,079	1,083
Total Capital Requirement, $/KW	1,199	1,204
First Year Costs		
Total O&M, $/kW-yr	44.50	44.00
Fixed O&M, $/kW-yr	35.58	35.17
Variable O&M, mill/kWh	1.27	1.25
Consumables, mills/kWh	2.11	3.00
Fuel, mills/kWh	8.92	8.95
Levelized (10 yr) O&M, mills/kWh		
Fixed O&M	6.5	6.4
Variable O&M	1.6	1.6
Consumables	2.7	3.8
Fuel	9.4	9.4
Levelized Carrying Charge, mills/kWh	20.5	20.6
Levelized Busbar Cost*, mills/kWh	40.7	41.9

* 30 years at 80% capacity factor

6.5 Increased Steam Turbine Size/Maximum Power Output (Case 5)

In the 2nd Generation PFB Combustion Plant a portion of the air discharging from the gas turbine compressor is extracted and utilized to support the operation of the carbonizer and the PCFB boiler. The unused balance of the compressor air drives and cools the gas turbine. In the baseline plant the PCFB boiler operates with 50 percent excess air and the unused oxygen in its flue gas supports the combustion of the syngas generated by the carbonizer. In burning this syngas the gas turbine topping combustor operates with approximately 70 percent excess air and yields a of 4.1 percent by volume oxygen concentration in its exhaust and 7.3 percent at the stack. Although MASB testing must be performed to define its lower oxygen limit, Siemens Westinghouse believes the MASB will be able to operate with oxygen levels as low as 1.5 percent in its exhaust; this will make more unused oxygen available for additional coal combustion. With the gas turbine fully loaded the heat from the additional coal would be used to increase the size of the steam turbine. Although this will reduce the gas turbine to steam turbine power ratio and, hence, the plant efficiency, because additional steam turbine power is relatively inexpensive, a lower cost of electricity can be achieved; this was shown in [ES-1].

Not knowing the limit of the MASB, the plant coal flow was increased to yield an MASB exhaust oxygen content of 3.5 percent, a value that was thought to be conservative.

Figure 6.5.1 presents a mass and energy balance for this plant named the Maximum Power Output Case and Tables 6.5.1 and 6.5.2 identify and compare its performance to that of the baseline plant. As seen from Table 6.5.1, a 3.2 percent increase in plant coal flow rate (8,634 lb/hr) increases the plant net output by 2.7 percent with the increase coming from a 12 MWe increase in gross steam turbine output. The increase in coal flow increases the char flow to the PCFB boiler and its excess air reduces to 4.5 percent. With excess air reduced, the PCFB boiler NOx reduces and the plant NOx reduces by about 24 percent to 0.13 lbs per million Btu of coal or 0.93 lbs per net megawatt of power produced.

The increase in steam turbine power reduces the gas turbine to steam turbine power ratio from 0.92 to 0.88 and the plant efficiency drops by 0.2 percentage points from 48.0 to 47.8 percent. Although the additional 12 MWe of output should result in a reduction in total plant costs and cost of electricity, the changes were expected to be small and were not investigated.

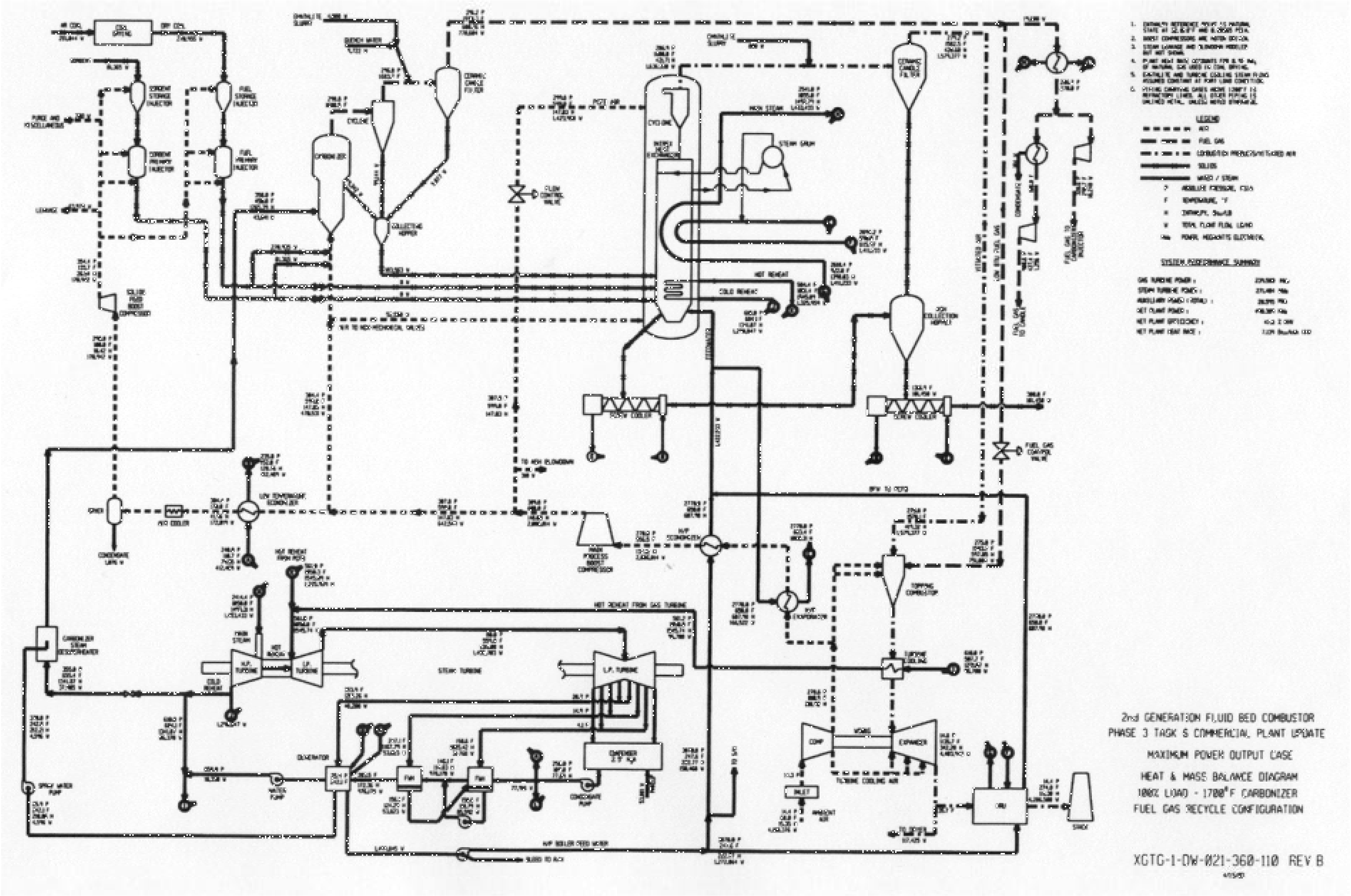

Figure 6.5.1 Maximum Power Case Plant Mass & Energy Balance

Table 6.5.1 Effect of Reduced Excess Air on Plant Performance

	Maximum Power	Baseline
Overall Plant Performance		
Net Efficiency,% (HHV)	47.80	48.00
Net Heat Rate, Btu/kWh	7139.00	7105.00
Net Power, MWe	490.31	477.56
Auxiliaries, MWe	20.60	20.90
Gross Power, MWe	489.50	498.46
Coal Flow Rate, lb/hr	281,040	272,406
Dolomite Flow Rate, lb/hr	80,959	78,864
Ash Flow Rate, lb/hr	101,450	98,369
Stack NOx, lb/MMBtu	0.13	0.17
Stack NOx, lb/MWe	0.93	1.22
Gas Turbine Parameters		
Nominal Combustor Exit Temp, ^{0}F	2,700	2,700
Gross Power, MWe	239.50	239.50
Steam Turbine Parameters		
Steam Throttle Flow Rate, lb/hr	1,453,433	1,384,989
Reheat Steam Flow Rate, lb/hr	1,422,659	1,354,234
Condenser Total Duty, MMBtu/hr	1,325	1,270
Gross Power, MWe	271.40	258.96

Table 6.5.2 Auxiliary Load Summary for Max. Power/Reduced Excess Air Plant (kWe)

Main Boost Compressor	6,950
Transport Boost Compressor	430
Fuel Gas Recycle Blower	100
Condensate Pumps	400
Feedwater Pumps	4,260
Boiler Forced Circulation Pumps	315
Circulating Water Pumps	2,330
Cooling Tower Fans	1,740
Coal Dryer Induced Draft Fan	260
Gas Turbine Auxiliaries	300
Steam Turbine Auxiliaries	300
Nitrogen Supply	0
Barge Unloading and Stacker/Reclaimer	180
Coal Handling	360
Dolomite Handling	70
Coal and Sorbent Feed	30
Ash Cooling and Handling	100
Filter Boost Compressor	350
Miscellaneous Balance of Plant (Note 1)	1,000
Transformer Loss	1,120
Total	20,595

Note 1 – Includes plant control systems, lighting, HVAC, etc.

6.6 CO_2 REMOVAL FOR SEQUESTERING (CASES 6 AND 7)

The baseline plant consumes coal at the rate of 272,406 lbs/hr and, in producing 477.5 MWe of electricity, operates with a stack CO_2 emission rate of 721,614 lbs/hr. With carbon dioxide (CO_2) being a greenhouse gas, future regulations may require that power plants remove 90 percent of their CO_2 for pipeline transport to a sequestering site. CO_2 can be removed by “cold gas” technologies that cool gases to ~100ºF to facilitate chemical or physical absorption by liquid solvents; these solvents are then regenerated/stripped to release a concentrated stream of CO_2 for the pipeline and allow reuse of the solvents. CO_2 cold gas removal and compression to a 1,200 psig pipeline pressure imposes a significant efficiency loss on power plants. Parsons in [ES-3] applied cold gas clean up technology to the back end of a PC boiler to determine the effect of 90 percent CO_2 removal on plant performance and economics. With the flue gas CO_2 concentration being relatively low, a chemical absorption, amine based solvent (inhibited MEA) was used. The PC plant operated with a super critical pressure double reheat steam cycle (3500psig/1050ºF/ 1050ºF/1050ºF) with a condenser back pressure of 2 inches of Hg.; the study showed the plant efficiency would reduce to 28.9 percent (was 40.5 percent before CO_2 removal).

MEA based CO_2 removal technology can also be applied to the back end of a 2nd Gen PFB Combustion Plant for 90 percent CO_2 removal. Figures 6.6.1 and 6.6.2 present a mass and energy balance (Case 6) for the baseline plant operating with this same removal process. In this arrangement the 274ºF exhaust gas from the HRU is cooled to 151ºF and passed through an absorber/stripper system where it is contacted by a lean aqueous MEA solution that chemically and selectively absorbs the CO_2. The CO_2 laden solution is then regenerated/stripped of CO_2 by heating with low temperature steam (322ºF at 65 psia). The released CO_2 is cooled, dried, and then compressed to 1200 psig for pipeline transport. Tables 6.6.1 and 6.6.2 identify and compare the performance of this plant with the baseline. The regeneration of the MEA solution requires a large amount of heat to break the CO_2 chemical bond and a 1,325,920 lbs/hr stripping steam requirement reduces the steam available for power generation. As a result the gross steam turbine power output drops from 259 MWe to 150.8 MWe and, with a significantly higher auxiliary power draw (CO_2 compressor requires 27.89 MWe), the plant efficiency drops from 48.0 to 33.1 percent. The resulting efficiency, however, is still significantly higher (33.1 versus 28.9 percent) than that of the PC plant operating with a more advanced steam cycle and a lower steam condenser back pressure. The use of cold gas cleanup, it must be pointed out, will increase 2nd Gen PFB plant sulfur capture efficiency to over 99 percent and reduce NOx emissions to near single digit ppm values.

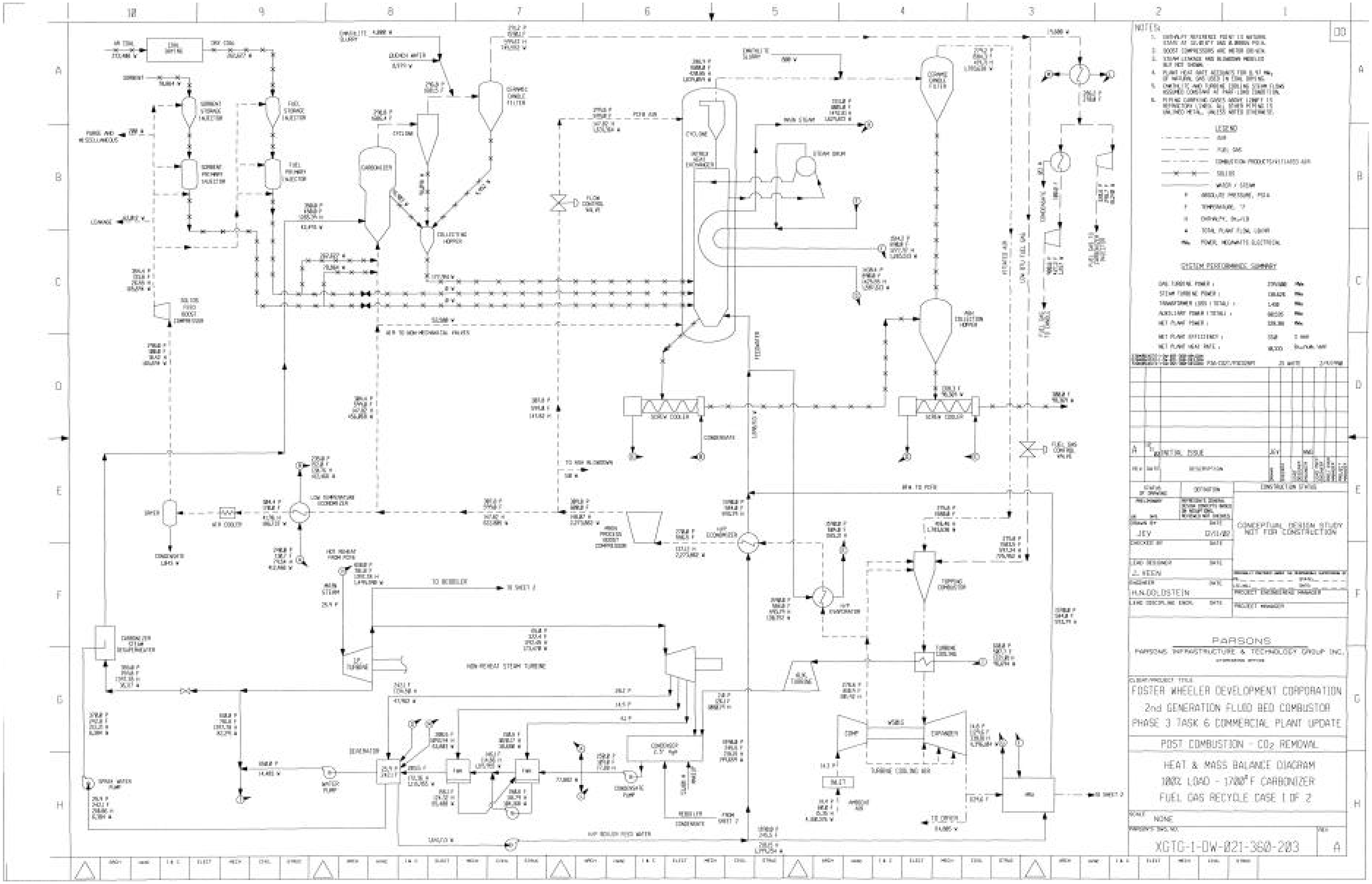

Figure 6.6.1 Post Gas Turbine CO_2 Removal Plant Mass and Energy Balance (Drawing #1)

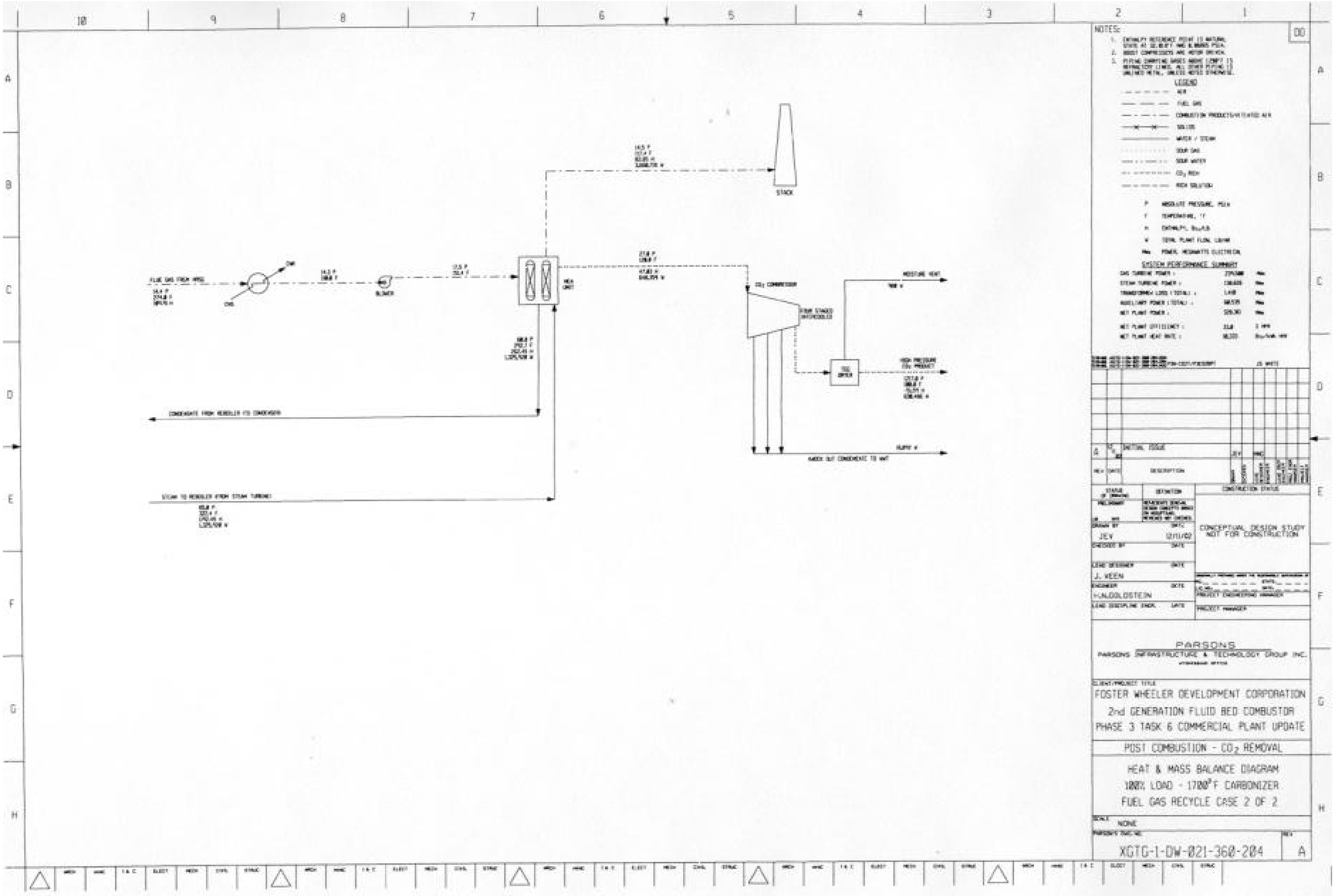

Figure 6.6.2 Post Gas Turbine CO_2 Removal Plant Mass and Energy Balance (Drawing #2)

Table 6.6.1 Effect of Post Gas Turbine CO_2 Removal on Plant Performance

	Post GT Removal	Baseline
Overall Plant Performance		
Net Efficiency,% (HHV)	33.10	48.00
Net Heat Rate, Btu/kWh	10305	7105
Net Power, MWe	329.24	477.56
Auxiliaries, MWe	61.08	20.90
Gross Power, MWe	390.31	498.46
Coal Flow Rate, lb/hr	272,406	272,406
Dolomite Flow Rate, lb/hr	78,864	78,864
Ash Flow Rate, lb/hr	98,369	98,369
Gas Turbine Parameters		
Nominal Combustor Exit Temp, ^{0}F	2,700	2,700
Gross Power, MWe	239.50	239.50
Steam Turbine Parameters		
Steam Throttle Flow Rate, lb/hr	1,629,810(1)	1,384,989(2)
Reheat Steam Flow Rate, lb/hr	NA	1,354,234
Condenser Total Duty, MMBtu/hr	450	1,270
Gross Power, MWe	150.81	258.96

(1) steam at 1414 psia and 1000F
(2) steam at 2414 psia and 1050F

Table 6.6.2 Auxiliary Load Summary for Post Gas Turbine CO_2 Removal Plant (kWe)

Main Boost Compressor	7,560
Transport Boost Compressor	420
MEA CO_2 Removal	2,730
Stand Alone Carbonizer Air Compressor	0
CO_2 Compressor	27,890
Fuel Gas Recycle Blower	100
Flue Gas Blower	13,280
Condensate Pumps	440
Feedwater Pumps	2,510
Boiler Forced Circulation Pumps	315
Circulating Water Pumps	1,150
Cooling Tower Fans	900
Coal Dryer Induced Draft Fan	250
Gas Turbine Auxiliaries	300
Steam Turbine Auxiliaries	300
Nitrogen Supply	0
Barge Unloading and Stacker/Reclaimer	170
Coal Handling	350
Dolomite Handling	70
Coal and Sorbent Feed	30
Ash Cooling and Handling	100
Filter Boost Compressor	350
Miscellaneous Balance of Plant (Note 1)	1,000
Transformer Loss	860
Total	61,075

Note 1 – Includes plant control systems, lighting, HVAC, etc.

In the above arrangement CO_2 removal occurred downstream of the gas turbine where CO_2 gas concentrations are a minimum and gas volumetric flows are a maximum. If the syngas and PCFB boiler flue gas are cooled before they reach the gas turbine, CO_2 gas concentrations are higher (diluting gas turbine combustion and cooling air flows are eliminated) and the 275 psia gas turbine inlet pressure markedly reduces the gas volumes to be processed. With the latter also increasing the CO_2 partial pressure, physical absorption solvents (such as Selexaol) may also be applicable. Screening calculations, first using Selaxol and then using Amine Guard FS solvents, were performed by UOP which indicated the latter chemical absorption solvent would be the more economical choice. Since optimization would require an extensive study, UOP provided rough sizing factors that would allow an estimation of the plant performance with pre-gas turbine CO_2 removal.

In the pre-gas turbine CO_2 removal case the carbonizer syngas and PCFB boiler flue gas streams would be cooled to ~100F via a series of heat exchangers and, during the cool down, the syngas would be humidified and water gas shifted to convert its CO to CO_2. Each cooled stream would enter its own absorption system where the amine solvent would absorb the CO_2. The two gas streams with 90 percent of their CO_2 removed would then be separately reheated, saturated with water vapor, and supplied to the gas turbine. The two CO_2 rich solvent streams would be sent to a flash tower operating at about 30 psia and then onto a stripper where the solvent is heated by steam. The gases released in the stripper are fed to the flash tower and the now CO_2 lean solvent is pumped/fed back to the absorption towers after reheating. The gases from the flash tower proceed onto the acid gas unit for processing and eventual compression to the 1200 psig pipe line pressure. Assuming the same Illinois No 6 coal and 2 inch condenser back pressure used in [ES-3], but keeping the baseline plant steam conditions and G class gas turbine, FWDC's proprietary computer models indicate the plant efficiency with pre-gas turbine CO_2 removal (Case 7) would increase to 35.4 percent. Since the 35.4 percent efficiency is based on rough sizing factors, rather than the intensive analysis UOP requires, the result is considered preliminary and a detailed mass and energy balance is not provided.

The above analyses show that 2nd Gen PFB Combustion Plants can incorporate CO_2 removing technologies either up stream or downstream of the gas turbine and their resulting plant efficiencies will be significantly higher than a PC plant also designed for CO_2 removal. Hence, 2nd Gen PFB Combustion Plants are in the unique position of being able to accommodate whatever proven or emerging technology is found to be optimal for power plant CO_2 removal.

6.7 Supercritical Pressure Steam Turbine (Case 8)

The steam cycle of 2nd Gen PFB Combustion Plants receives its heat primarily from the PCFB boiler and to a lesser extent from the gas turbine exhaust; the former, with its 1600ºF operating temperature, is a source of high-grade heat that allows the plant to operate with the most advanced steam conditions. The baseline plant operates with a subcritical pressure steam cycle and Figure 6.7.1 presents a mass and energy balance for the plant operating with a super critical pressure double reheat steam turbine (4000psig/1100ºF/1100ºF/1100ºF/2-1/2 in. Hg.); although the 4000 psig pressure and 1100ºF superheat and double reheat steam temperatures are slightly higher than current U.S. practice, they were selected because they are already being introduced in other parts of the world (Nordjylland at 4500psig/1100ºF/1100ºF/1100ºF). Super critical pressure steam turbines with double reheat are only available in larger sizes and, to meet the increased steam flow/combustion requirements, the plant transforms into a two module configuration, e.g., two carbonizer-PCFB boiler-gas turbine modules are used to supply steam to one large steam turbine.

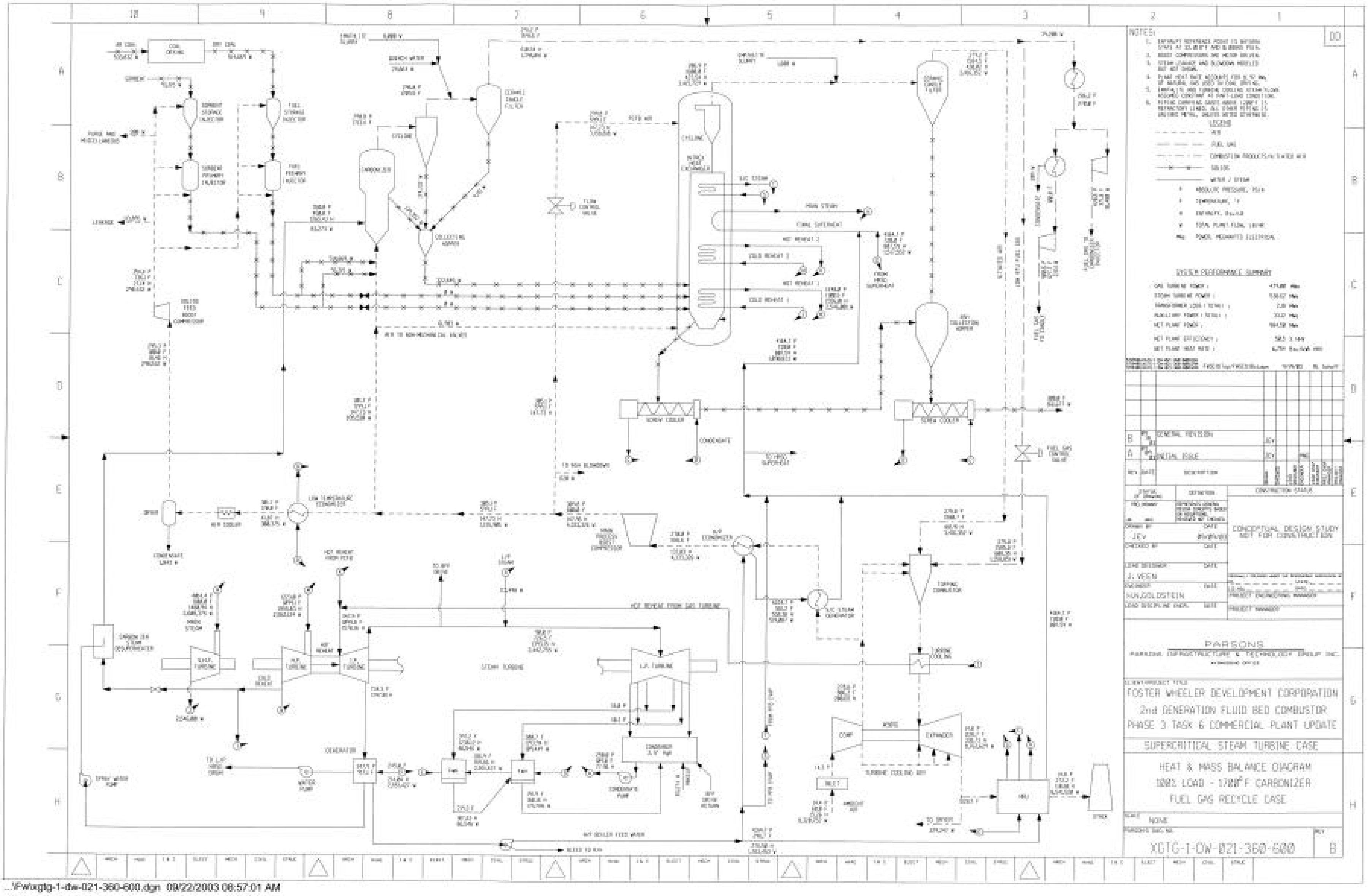

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Figure 6.7.1 Supercritical Pressure Steam Plant Mass and Energy Balance

Tables 6.7.1 and 6.7.2 summarize plant performance data and reveal that switching to the supercritical pressure steam turbine will increase the plant efficiency to 50.5 percent with a net power output of 984.5 MWe. This case shows that as steam cycles advance in the future to higher and higher pressures and temperatures, 2nd Gen PFB Combustion Plants can easily incorporate those advanced conditions for increased efficiencies.

Table 6.7.1 Effect of Supercritical Pressure Steam on Plant Performance

	Super Critical Pressure	Baseline
Overall Plant Performance		
Net Efficiency, % (HHV)	50.50	48.00
Net Heat Rate, Btu/kWh	6754.00	7105.00
Net Power, MWe	984.5	477.56
Auxiliaries, MWe	33.10	20.90
Gross Power, MWe	1017.60	498.46
Coal Flow Rate, lb/hr	533,832	272,406
Limestone Flow Rate, lb/hr	93,315	78,864
Ash Flow Rate, lb/hr	166,677	98,369
Gas Turbine Parameters		
Nominal Combustor Exit Temp, ^{0}F	2,700	2,700
Gross Power, MWe	479.00*	239.50
Steam Turbine Parameters		
Steam Throttle Flow Rate, lb/hr	2,608,375	1,384,989
Reheat Steam Flow Rate, lb/hr	2,552,124	1,354,234
Condenser Total Duty, MMBtu/hr	2,293	1,270
Gross Power, MWe	538.62	258.96

* two W501G gas turbines

Table 6.7.2 Auxiliary Load Summary for Plant Using Supercritical Pressure Steam (kWe)

Main Boost Compressor	14,420
Transport Boost Compressor	760
Fuel Gas Recycle Blower	200
Condensate Pumps	740
Feedwater Pumps	2,870
Steam Turbine Drive Boiler Feedwater Pumps (Note 2)	*10,780*
Boiler Forced Circulation Pumps	0
Circulating Water Pumps	3,780
Cooling Tower Fans	2,830
Coal Dryer Induced Draft Fan	500
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	600
Nitrogen Supply	0
Barge Unloading and Stacker/Reclaimer	340
Coal Handling	700
Limestone Handling	140
Coal and Sorbent Feed	60
Ash Cooling and Handling	200
Filter Boost Compressor	700
Miscellaneous Balance of Plant (Note 1)	1,500
Transformer Loss	2,180
Total	33,120
Note 1 - Includes plant control systems, lighting, HVAC, etc.	
Note 2 - Steam Turbine Boiler Feedwater Pump auxiliary load not included in total	

6.8 Summary of Sensitivity Study

Table 6.8.1 summarizes the results of the sensitivity study. The costs and operating data presented for the baseline plant and its first four sensitivity study cases show that 2nd Gen PFB Combustion Plants will be more efficient (48.2 versus 38.9 percent), less expensive ($1,077 versus $1,202/KW), and operate with a lower cost of electricity (40.7 versus 46.4 mills/kWh) than a comparable PC plant; based on Case 4, a 2nd Gen PFB Combustion Plant can be 24 percent more efficient and have a 12 percent lower cost of electricity. These advantages are achieved using air-blown, pressurized fluidized bed technologies operating with crushed coal and limestone; there is no need for oxygen generating air separation units or chemical plant processes.

In Cases 5 though 8 the effect of alternative operating conditions on overall plant performance were investigated. Case 5 shows that increasing the size of the steam turbine without increasing steam conditions will result in a reduction in plant efficiency but, per an analysis presented in [ES-1], should result in a reduction in cost of electricity. If the baseline plant should require 90 percent removal of its CO_2 via cold gas technologies, it can be performed either upstream or downstream of the gas turbine. With downstream removal the plant efficiency will drop to 33.1 percent whereas upstream removal, based on a preliminary analysis performed by FWDC, indicates an efficiency of 35.4 percent; both values are considerably higher than that of a super critical pressure PC plant also designed for CO_2 removal. Incorporating a super critical pressure steam turbine will increase the efficiency of the baseline plant by 2.3 percentage points yielding a value of 50.5 percent.

Table 6.8.1 Sensitivity Study Results

Case	Description	Net Output, MWe	HHV Efficiency,%	Total Plant Cost, $/KW	COE, mills/kWh	COE% less than PC**
	Baseline Plant	477.56	48.0	1,083	41.9	9.7
1	with Limestone Sorbent	469.51	48.2	1,085	40.9	11.9
2	with Large Filter Vessels	477.56	48.0	1,077	41.7	9.9
3	with Metal Filters	467.36	45.8	1,124	43.0	7.3
4	with Limestone & Large Filter Vessels	469.51	48.2	1,079	40.7	12.3
5	with Large Steam Turbine	490.31	47.8	ND*	ND*	ND*
6	with Post Gas Turbine CO_2 Removal	329.24	33.1++	ND*	ND*	ND*
7	with Pre-Gas Turbine CO_2 Removal	422.10 (Preliminary)	35.4 (Preliminary)	ND*	ND*	ND*
8	with Supercritical Steam Turbine	984.50	50.5	ND*	ND*	ND*

* Not Determined
** Pulverized Coal-Fired Plant with FGD at $1,202/KW and COE of 46.4 mills/kWh
++Efficiency of Super Critical Pulverized Coal-Fired Plant with 90% CO2 Removal is 28.9%

In [ES-3] the effect of 90 percent CO_2 removal on two Illinois No 6 coal fired power plants were studied. Both plants used a steam condenser back pressure of 2 inches of mercury; one used a PC fired boiler operating with a double reheat supercritical pressure steam cycle and the other an Integrated Gasification Combined Cycle (IGCC) Plant operating with an H Class gas turbine. Table 6.8.2 compares the baseline plant with the findings of that study. Even though the baseline operates with less advanced steam and or gas turbines, it yields a much higher efficiency than both of these alternative technologies, e.g., 48.0 versus 43.1 and 40.5 percent. The 2nd Gen PFB Combustion Plant can remove its CO_2 either upstream of (Case 7) or downstream of (Case 6) the gas turbine. Downstream CO_2 removal reduces the plant efficiency to 33.1 percent versus 28.9 percent for the super critical pressure PC plant. A preliminary analysis of pre-gas turbine removal (Case 7) indicates an efficiency of 35.4 percent, a value similar to that predicted for the IGCC plant operating with a more advanced H Class gas turbine. Although 90 percent CO_2 removal will reduce the efficiency of 2nd Gen PFB Combustion Plants, their reduced values will be at least equal to if not superior to that of other coal based power generation technologies.

Table 6.8.2 Comparison of Coal-Fired Plants with 90% CO_2 Removal

Plant	Gas Turbine	CO2 Capture			
		no	no	yes	yes
		Net MWe	Efficiency,%	Net MWe	Efficiency,%
PC with SC Steam*	NA	462.1	40.5	329.5	28.9
IGCC	H Class	424.5	43.1	386.8	35.4
2nd Gen PFB**	G Class	477.6	48.0		
Pre Gas Turbine				Prelim @ 422.1	Prelim @ 35.4
Post Gas Turbine				329.2	33.1

*3500psig/1050F/1050F/1050F
**2400psig/1050F/1050F

Section 7

RESEARCH AND DEVELOPMENT NEEDS

The new technology components of the 2nd Gen PFB Combustion Plant are the carbonizer, char transfer N valves, PCFB boiler, ceramic candle filters, and syngas burners (MASBs) used in the gas turbine topping combustor. Each of these components has been tested separately at a pilot plant scale to determine their individual performance characteristics. In addition a 12 inch diameter carbonizer and a 13 inch diameter PCFB combustor have been/operated as an integrated subsystem. The latter was conducted at approximately 120 psig and involved approximately five continuous days of safe controlled transfer of char between these two units during which two different coals, one petroleum coke, one dolomite, and two different limestones were tested/changed on the fly. All of these tests were successful, however, some components had limited test times, some need further testing to define operating limits, some need improved materials of construction that make them more durable, corrosion resistant, etc (ceramic candle filters), etc.

Consequently it is recommended that R&D efforts continue as a minimum to:

- develop improved candle materials for high temperature filtration applications,
- determine the lower oxygen limit and part load characteristics of the MASB,
- develop gas turbine modifications that allow export of large quantities of air, and
- develop a less expensive alternative to lock hoppers for material feeding/removal.

As with any new technology, the first demonstration will not be without risk. The Section 6 Sensitivity Study has investigated several alternative 2nd Gen PFB plant configurations. In the Metal Filter Case the syngas, char, and PCFB boiler flue gas are cooled before they are transferred to downstream components. Cooling the gases eliminates the need for alkali gettering and enables commercially proven, porous metal candle, filtration systems to be used to protect the gas turbine from erosion and deposition. In addition, operating requirements of downstream components are eased thereby simplifying the design of interconnecting piping and gas turbine valving, burners, and casing modifications. Similarly, by cooling the char the hot non-mechanical N valves and ceramic lined slide valves provided in the carbonizer to PCFB boiler char transfer lines can be replaced by lower temperature, and or conventional components. The low temperatures associated with the metal filter arrangement minimize technology and component risks. As a result the metal filter approach linked with a small, well proven gas turbine is recommended for the first demonstration of 2nd Gen PFB technology; while such a demonstration is underway, the above R&D efforts will prepare for the next step forward to the large capacity peak efficiency plant configuration.

Section 8

CONCLUSIONS

Comparison of the updated 2nd Gen PFB Combustion Plant design with that of a comparable PC plant operating with the same coal, limestone, sulfur capture efficiency, NOx emission rate, and steam cycle conditions continues to show the attractiveness of this new type of plant. When operating with Pittsburgh No 8 coal and limestone, a Siemens Westinghouse W501G gas turbine, and a 2400psig/1050F/1050F/2½" Hg steam turbine, a nominal 500 MWe 2nd Gen PFB combustion plant has:

1. an HHV efficiency of 48.2%-----------------a value 24% higher than the PC plant
2. a total plant cost of \$1,079/KW-------------a value 10% less than the PC plant
3. a 40.7 mills/kWh cost of electricity----------a value 12% less than the PC plant
4. water consumption of 354 gal/MWe---------a value 40% less than the PC plant
5. ash production rate of 178 lb/hr/MWe-------a value within 1% of the PC plant
6. CO2 release rate of 1,468 lb/hr/MWe-------a value 19% less than the PC plant
7. emissions well below NSPS values
    - 97% sulfur capture efficiency for a stack SO_2 release of 0.97 lb/hr/MWe
    - NOx emission is 1.22 lb/hr/MWe or 0.17 lb/hr/MMBtu
    - particulate emission is less than 0.003 lb/MMBtu

Much of the equipment required by a 2nd Gen PFB Combustion Plant is state of the art and is available with commercial guarantees. The layout and construction methods employed for the plant reflect techniques/practices already utilized in either the utility or other major industries.

With regard to the cost estimating of the new technology components, most of this equipment has been operated at a smaller scale or at atmospheric pressure and, for the purpose of this study, they were scaled up in size, pressure, or both to provide a conceptual design/costing basis. When estimating the cost of the plant, those new components and their subsystems were assigned process contingencies based on engineering judgment and EPRI Technical Assessment Guidelines [ES-2]. With the PC plant being a mature technology, it was not assessed any process contingency charges and a 15 percent project contingency was applied to both overall plant cost estimates. When added up, the charges associated with 2nd Gen PFB Combustion Plant process contingencies total approximately 34 million dollars. All of the above costs are given in January 2002 dollars. Compared with the original study performed in 1987, the 2nd Gen PFB Combustion Plant has essentially maintained its efficiency advantage but its cost of electricity advantage has reduced from 22 to 12 percent; the reason for the latter is that despite 15 years of inflation, PC total plant costs have not increased, primarily because:

- advances in scrubber technology have markedly reduced scrubber costs and
- structural steel costs on a dollar per ton basis are now half that previously used.

With carbon dioxide (CO_2) being a greenhouse gas, future regulations may require that power plants incorporate CO_2 removal for sequestration. Similar to PC and Integrated Coal Gasification Combined Cycle (IGCC) plants, 2nd Gen PFB Combustion Plants can accommodate 90 percent CO_2 removal using "cold" gas cleanup technologies, e.g., gases are cooled to ~100ºF to enable

CO_2 absorption by either chemical or physical solvents followed by stripping/solvent regeneration. Although the 2nd Gen PFB Combustion Plant will experience an efficiency loss, its operating efficiency with CO_2 removal will be equal to if not significantly higher than that of competing coal fired technologies.

In addition the use of cold gas cleanup will increase the plant sulfur capture efficiency to over 99 percent and reduce NOx emissions to near single digit ppm values. Should the future also bring advances in both gas turbine and steam turbine technologies, the 2nd Gen PFB Combustion Plant, being a hybrid, can easily utilize their advantages. For example operation with a super critical pressure double reheat steam turbine (4000psig/1100F/1100F/1100F/2½ in. Hg.) will increase the plant HHV efficiency to 50.5 percent.

A 2nd Generation PFB Combustion Plant offers electric utilities significantly higher efficiencies, lower costs of electricity, lower emissions, and lower water consumption rates. In addition it offers simplicity in that it operates with crushed coal and limestone and does not require oxygen generating air separation units, chemical cleanup systems, or SCR systems. With maturity, it is expected to operate with PC plant availabilities. If future emission regulations should require mercury capture and or CO_2 capture/sequestration, it can incorporate those processing steps found best for their removal (they can be incorporated either upstream of the gas turbine where gas volumes are reduced or downstream of the gas turbine where pressures are reduced). In addition it can easily accommodate future gas turbine and steam turbine advances that will further increase its efficiency advantage.

2nd Generation PFB Combustion Plants appear ideally suited for meeting the present and future needs of the electric utility industry. Recognizing that the key components of this new technology have been tested separately at the pilot plant stage, the next step forward is construction of a small scale, fully integrated power producing system. As with any new technology, deployment of the first unit will involve risk. From the stand point of the 2nd Gen PFB, the risk lies mainly with firing the syngas and PCFB boiler flue gas hot, as the 1600ºF temperatures involved impose severe design requirements on downstream components, e.g., filters, piping, and gas turbine valving and burners. Since cooling the syngas and PCFB boiler flue gas to allow operation with commercially proven metal filters eases the design requirements of all downstream components and eliminates all gas turbine corrosion, erosion, and fouling issues, the metal filter configuration is recommended for the first demonstration of 2nd Gen PFB technology.

Section 9

REFERENCES

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Section 10

BIBLIOGRAPHY

None required

Section 11

ACRONYMS AND ABBREVIATIONS

AFDC	Cost of Financing During Construction
BOP	Balance of Plant
CF	Capacity Factor
CO_2	Carbon Dioxide
COE	Cost of Electricity
CRT	Cathode Ray Tube
DCS	Distributed Control System
DOE	U.S. Department of Energy
EDI	Electrodeionization
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
FC	Delivered Fuel (Coal) Cost in $/MMBtu
FWDC	Foster Wheeler Development Corporation
I&C	Instrumentation and Control
ID	Inside diameter
I/O	Input/Output
IP	Intermediate Pressure
Hg	Mercury
HHV	Higher Heating Value
HP	High Pressure
HVAC	Heating, Ventilation, and Air Conditioning
LHV	Lower Heating Value
LP	Low Pressure
MCC	Motor Control Center
NERC	North Americaan Electric Reliability Council
NOx	Oxides of Nitrogen
NPHR	Net Plant Heat Rate
O&M	Operating and Maintenance
OD	Outside Diameter
OJ	Operating Jobs
OLC	Operating Labor Charge
PC	Pulverized Coal
PCFB	Pressurized Circulating Fluidized Bed
PFB	Pressurized Fluidized Bed
PLC	Programmable Logic Controller
RAM	Reliability, Availability, and Maintainability
RCRA	Resource Conservation and Recovery Act
RO	Reverse Osmosis
SiC	Silicon Carbide
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide

SWPC	Siemens Westighouse Power Corporation
TAG	Technical Assessment Guide
TCR	Total Capital Requirement
TG	Steam Turbine Generator
TPC	Total Plant Cost
TPI	Total Plant Investment