Report

Coal Power Plant Technology Evaluation for Dry Fork Station

Prepared for

Basin Electric Power Cooperative

Bismarck, ND

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Background

In December 2004, Basin Electric announced plans to build a 250 MW (net) coal-based generation resource in Northeast Wyoming. Basin Electric's goal for this new generation resource is to build a high quality, environmentally sound, cost-effective generation facility.

Basin Electric and its consulting engineers conducted extensive reviews of the current progress being made in alternative coal-based technologies, including the proven pulverized coal (PC) and circulating fluidized bed (CFB) boilers, and the demonstration integrated gasification combined cycle (IGCC) power plants. As a result of this review, Basin Electric and consultants have determined that the project can meet or exceed all of the project goals by utilizing the latest generation of air pollution control (APC) technology with a PC boiler. A PC unit with state of the art emission control equipment offers performance that exceeds the proven capabilities of CFB or IGCC systems.

In May 2005, based on a revised load forecast for Basin Electric's member cooperatives, the annual average net plant output for the proposed coal unit was increased to 350 MW (net). The technology comparison at this rating is virtually identical to the 250 MW design case. The plant was named the Dry Fork Station in August 2005.

This conceptual level technology evaluation was conducted to address the advantages and limitations of PC, CFB and IGCC coal-based power generation technologies for the new Dry Fork Station. The evaluation addresses the capability of each technology to fulfill the need of the project based on technical, environmental, reliability, commercial, and economic evaluation criteria.

The basis of this evaluation is a coal-fueled power plant that will be mine mouth using PC, CFB or IGCC technology. The facility would be base loaded with a minimum 85 percent capacity factor and 90 percent availability. While not part of the current proposal, the possibility does exist for the future expansion of the site with a second unit. The current online operational date for the facility is January 2011.

Basin Electric desires to identify the most prudent power generation technology for this new coal-fired power plant. That identification process is guided by these desired characteristics for the proposed generation:

- Baseload Capacity
- Environmental Compliance
- High Reliability and Availability
- Commercially Available and Proven Technology
- Cost Effective

Coal-based power generation technology selected for this project must be capable of meeting the desired characteristics listed above.

Technical Evaluation

The main incentive for IGCC development has been that units may be able to achieve higher thermal efficiencies than PC plants, be able to match the environmental performance of gas-fired plants, and potentially provide a more cost-effective means of removing CO_2 should that become a future regulatory requirement. However, the thermal efficiencies of new PC plants using superheated steam have also increased as has their environmental performance. The coal plant technology configurations selected for evaluation are shown in Table ES-1.

The PC configuration selected uses a conventional high dust/high temperature SCR system for NO_x control, and a Circulating Dry Scrubber (CDS) FGD system for SO_2 control.

The CFB configuration selected uses a Selective Non-Catalytic Reduction (SNCR) system for NO_x control, and limestone addition in the boiler with a downstream CDS FGD system for SO_2 control.

The two IGCC configurations selected for evaluation represent a conventional IGCC unit and an ultra-low emissions IGCC unit. The conventional IGCC unit uses an amine gas treatment system to reduce H_2S to approximately 25 ppmv in the syngas sent to the combustion turbine generators (CTGs) for SO_2 control, and water injection or nitrogen dilution with low-NO_x burners in the CTGs for NO_x control.

The ultra-low emissions IGCC unit uses a Selexol gas treatment system to reduce H_2S to approximately 10 ppmv in the syngas sent to the CTGs for SO_2 control, water injection with low-NO_x burners in the CTGs and an SCR system for NO_x control, and a catalytic oxidation catalyst (Cat-Ox) system for CO control.

TABLE ES-1
Coal Plant Technology Evaluation Criteria
Basin Electric Dry Fork Station Technology Evaluation

Criteria	PC	CFB	Conventional IGCC	Ultra-Low Emission IGCC
Net Plant Output (MW)	250 MW	250 MW	250 MW	250 MW
Net Plant Heat Rate (Btu/kW-Hr)	10,512	10,872	11,450	11,132
Annual Plant Capacity Factor (%)	85% Coal	85% Coal	15% Natural Gas, 70% Coal	15% Natural Gas, 70% Coal
SO_2 Control System	CDS FGD	$CaCO_3$ in Boiler and CDS FGD	Amine Syngas Treatment for H_2S Removal	Selexol Syngas Treatment for H_2S Removal
NO_x Control System	LNB and SCR	SNCR	LNB and Water Injection	LNB, Water Injection and SCR
CO Control System	Combustion Controls	Combustion Controls	Combustion Controls	Cat-Ox

Notes: CDS FGD – Circulating Dry Scrubber Flue Gas Desulfurization System; LNB – Low NOx Burners; SCR – Selective Catalytic Reduction; SNCR – Selective Non-Catalytic Reduction; Cat-Ox – Catalytic Oxidation

Environmental Evaluation

A PC boiler combined with appropriate APC technology offers similar emission rates to a CFB boiler for SO_2, NO_x, particulate matter, mercury and other hazardous air pollutants (HAPs). A PC boiler based plant with the latest generation of proven APC technology offers lower SO_2 and NO_x emission rates as compared to the two U.S. demonstration IGCC plants at the Public Service of Indiana (PSI) Wabash River and Tampa Electric Company (TECO) Polk stations.

Future IGCC plants have the potential of offering lower SO_2 and NO_x emission rates, but at a significantly higher total plant capital cost and project risk compared to a PC unit along with the uncertainties associated with the use of this developing integration of technologies (including costly poor plant availability for a number of years). Table ES-2 compares the proposed Dry Fork Station PC emission rates with the current annual emission rates from existing CFB commercial plants and from existing U.S. IGCC demonstration plants.

TABLE ES-2
Comparison of Coal Combustion Technology Emission Rates
Basin Electric Dry Fork Station Technology Evaluation

	Emission Rates for Coal Combustion Technologies (Lb/MMBtu)		
Pollutant	**PC (Potential BACT)**	**CFB (Existing U.S. Commercial Plants)**	**IGCC (Existing U.S. Demonstration Plants)***
SO_2	0.10	0.10	0.17
NO_x	0.07	0.09	0.09
PM_{10}**	0.019	0.019	0.011
CO	0.15	0.15	0.045
VOC	0.0037	0.0037	0.0021

Notes:

* PSI Energy Wabash River Station and TECO Polk Power Station Existing IGCC Demonstration Plants.

** PM_{10} includes filterable and condensable portions.

Reliability Evaluation

Both PC and CFB technologies have demonstrated high reliability. IGCC technology has demonstrated very low reliability in the early years of plant operation. Higher reliability has been recently demonstrated after design and operation changes were made to the facilities, however, the availability of IGCC units is still much lower than PC and CFB units.

The PC and CFB technologies are capable of achieving a 90 percent annual availability, an 85 percent annual capacity factor, and are suitable for baseload capacity. The IGCC technology has only demonstrated a 70 percent annual availability and 70 percent capacity factor. Using an IGCC for a baseload unit would require natural gas as a backup fuel for the combustion turbine combined cycle section of the plant or duplicate spare equipment. The gasification islands in the four IGCC demonstration plants have generally only been able to achieve up to 70 percent capacity factors, even after 10 years of operation. The annual availability and capacity factor data for the two U.S. IGCC Demonstration Plants are compared against the expected annual availability and capacity factor for a new PC unit in Figures ES-1 and ES-2. The availability for the last three years of data reported for the Polk IGCC unit (2001 to 2003) is calculated to be 73 percent. The availability for the three years of data reported for the Wabash River IGCC unit (1997 to 1999) is calculated to be 48 percent. The capacity factor for the last three years of data reported for the Polk and Wabash River IGCC units (1999 to 2001) is calculated to be 70 percent and 38 percent, respectively.

Figure ES-1

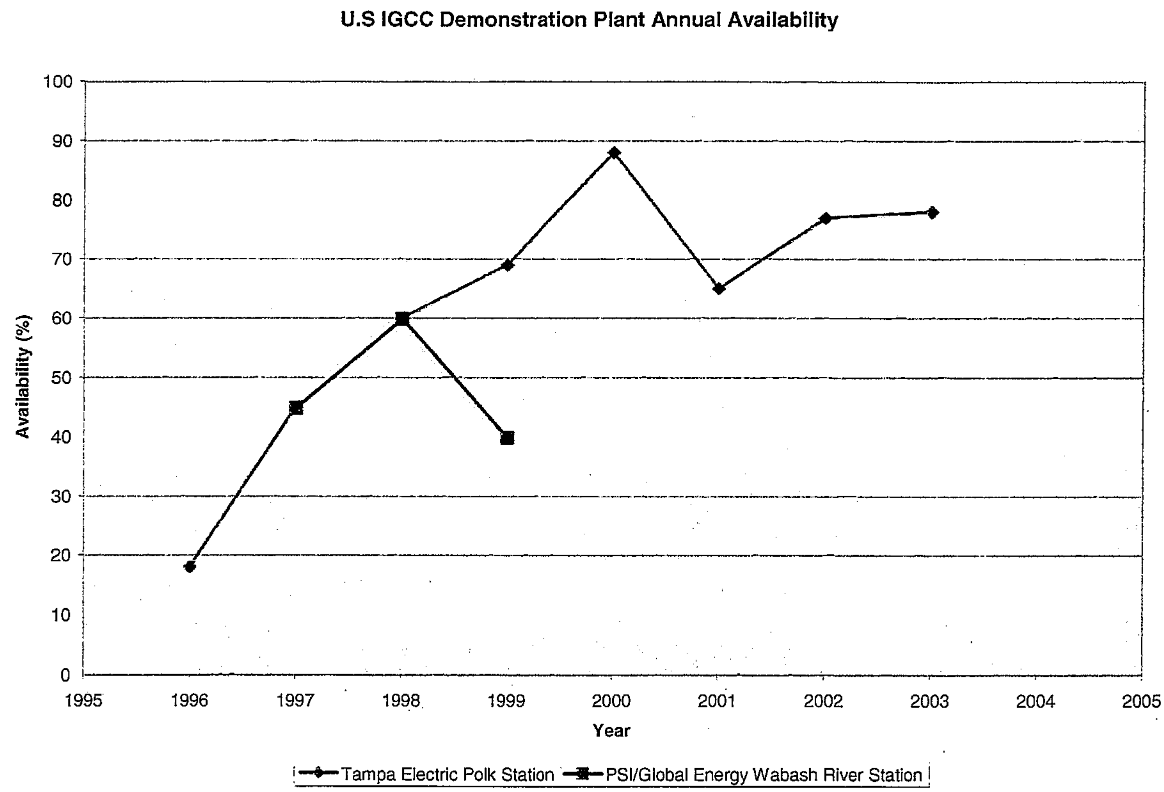
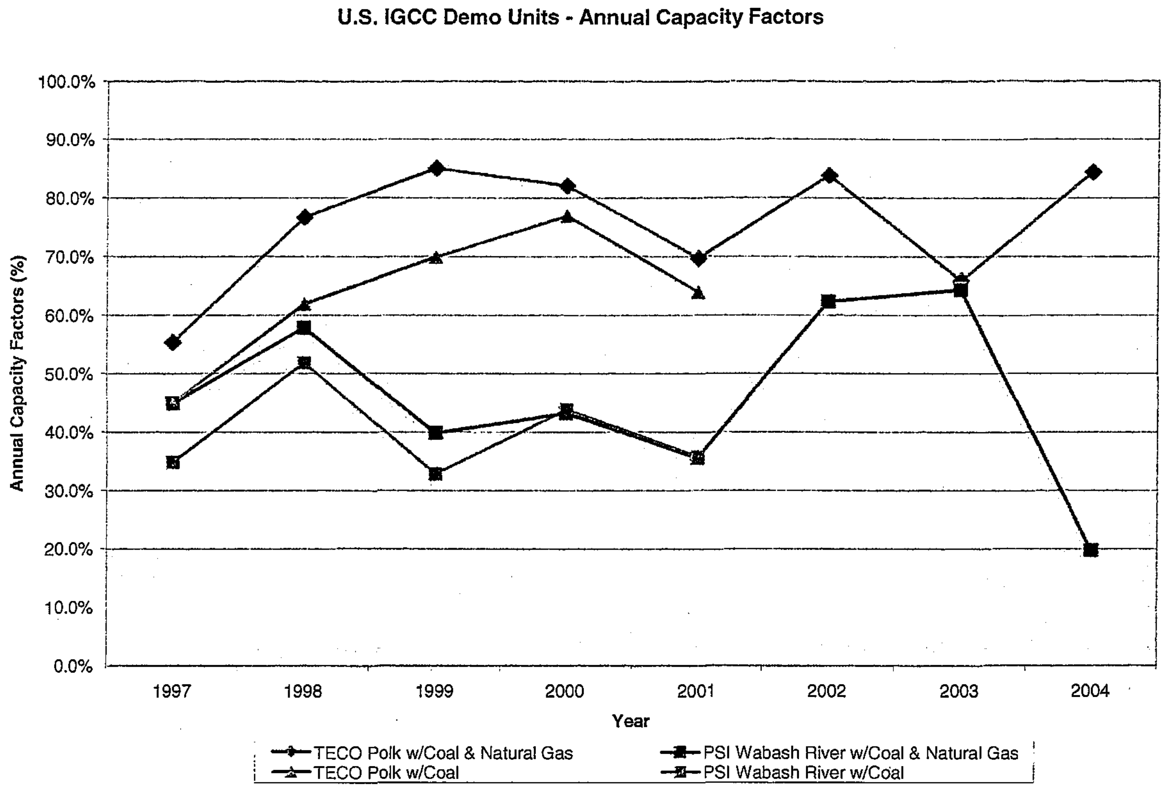


Figure ES-2



Commercial Evaluation

Basin Electric received proposals from only three of the six IGCC technology leaders in response to an IGCC Feasibility Study Request for Proposal (RFP) in February 2005. All three of the proposals received were deemed unresponsive; they did not specify the terms and conditions which would be proposed for this type of commercial offering and did not describe the financial backing which could be offered for such guarantees and warranties, as specified in the RFP. All parties required further studies, additional money, and more time to get to a point where some of the performance and commercial information requested would be available.

There is a lack of acceptable performance warranties/guarantees for commercial IGCC offerings. The reliability of the technology is an important factor given that this plant is intended for baseload generation and represents approximately 10 percent of the Basin Electric generation portfolio. In the business of building large scale generation resources, it is standard practice for suppliers to offer plant performance guarantees that are specific and precise in nature and are a direct reflection of their confidence that the plants will perform as desired. The providers of IGCC technology were unwilling to provide such assurances, greatly increasing the risk and potential future costs should this option be chosen and fail to perform to expectations. This is a clear indication of how much more development this technology requires before it can be considered to fill the role of reliable, large-scale generation.

While IGCC technology holds much future promise, it is still an emerging technology, especially for the lower ranked sub-bituminous coal typical of the Powder River Basin of Wyoming. For future development of this new and promising technology in Wyoming, Basin Electric would be open to considering a partnership with state or federal agencies to help mitigate the risk for their membership.

Economic Evaluation

A PC boiler is expected to have a slightly lower cost compared to a CFB boiler. However, no CFB boilers have been built and operated at the 350 MW net size required for the Basin Electric project. For a CFB based design, the project would have to use a boiler size that is not yet proven, or use two CFB boilers at 50 percent size which would result in an approximate plant cost increase of 20 percent.

IGCC plants are most competitive in capital and busbar cost with conventional PC plants based on high heating value/high sulfur content eastern bituminous coal or petroleum coke fuels, plant elevations near sea level and a plant size of at least 500 to 600 MW. The Basin Electric Dry Fork Station project will be a nominal 350 MW (net) plant at an elevation of 4,250 feet with low heating value/low sulfur Powder River Basin (PRB) coal fuel. An IGCC plant for this project would incur a significant capital and operating cost penalty due to the small plant size and lower rank high moisture fuel, and a significant power output derating for the plant gas turbines due to the high plant elevation. Based upon available data, an IGCC unit for the NE Wyoming project would be approximately 50 percent higher in capital cost and approximately twice the busbar cost of electricity (COE) generated compared to a PC unit.

The first year busbar COE for the four evaluated technology cases are compared in Figure ES-3.

Conclusions and Recommendations

PC technology is capable of fulfilling Basin Electric's need for new generation, and is recommended for the NE Wyoming Power Project.

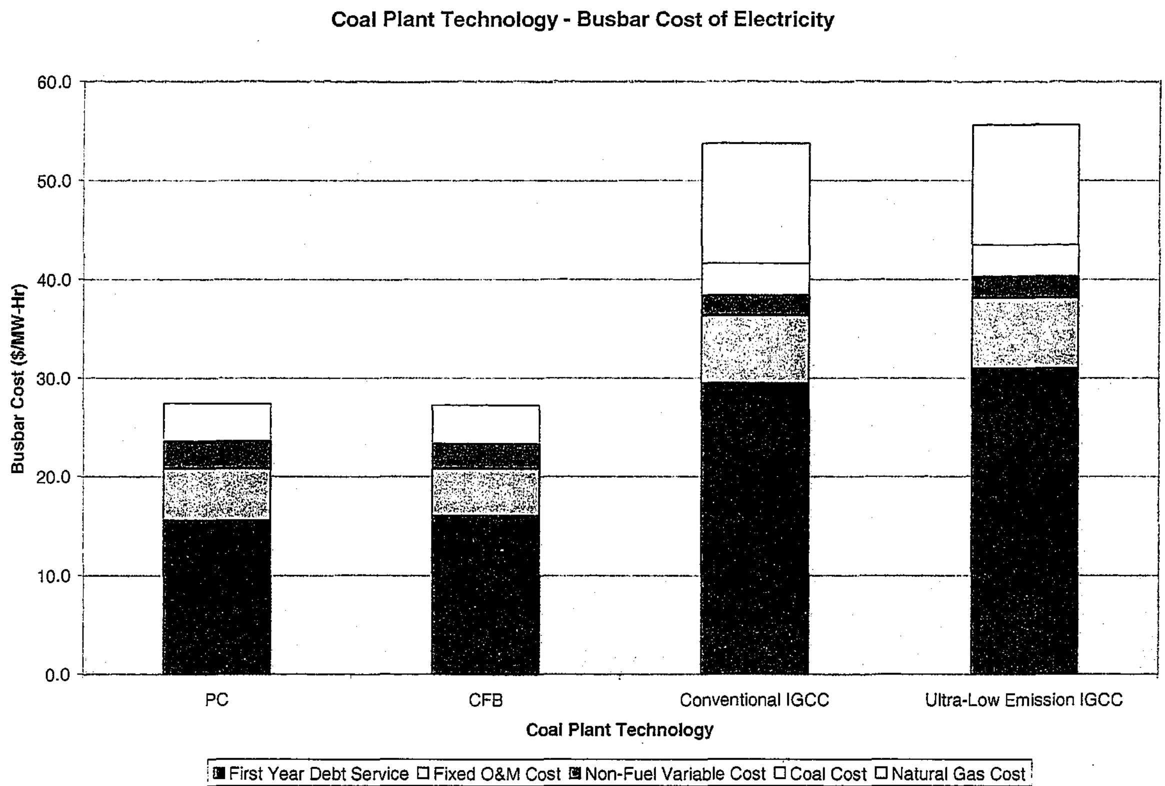
CFB technology meets Basin Electric's need; however, it lacks demonstrated long-term operating experience on PRB coal.

IGCC technology is judged not capable of fulfilling the need for new generation. IGCC does not meet the requirement for a high level of reliability and long-term, cost-effective, and competitive generation of power. In addition to higher capital costs, there are problem areas, discussed in this report, that have not demonstrated acceptable reliability. Current approaches to improving reliability in these areas result in less efficient and/or higher capital cost facilities, negatively impacting the cost-effectiveness.

DOE has a Clean Coal Technology program with the goal of providing clean coal power-generation alternatives which includes improving the cost-competitiveness of IGCC. However, the current DOE time frame (by 2015) does not support Basin Electric's 2011 needs.

IGCC offers the potential for a more cost effective means of CO_2 removal as compared to PC and CFB technologies should such removal become a requirement in the future. However, at this time, it is only speculative as to if such requirements will be enacted, when they will be enacted, and what they will consist of and apply to if enacted. The risk of installing a more costly technology, that has not been proven to be reliable and for which strong commercial performance guarantees are not available, is far too great for Basin Electric to take on for such speculative purposes.

Figure ES-3



SECTION 1.0

Introduction

In December 2004, Basin Electric Power Cooperative (BEPC) announced plans to build a 250 MW (net) coal-based generation resource in Northeast Wyoming. Basin Electric's goal for this new generation resource is to build a high quality, environmentally sound, cost-effective generation facility.

CH2M HILL was requested by Basin Electric to evaluate coal combustion technologies for the NE Wyoming Power Project. This investigation was initiated in July 2004 as part of the Technology Assessment Study, and continues today as an ongoing investigation.

The facility, now named the Dry Fork Station, would be base loaded with a minimum 85 percent capacity factor and 90 percent availability. The currently targeted online operational date for the unit is January, 2011. This evaluation compares the Pulverized Coal (PC), Circulating Fluid-Bed (CFB), and Integrated Gasification Combined Cycle (IGCC) technologies based on the capability of each technology to fulfill the need of the project based on technical, environmental, reliability, commercial and economic evaluation criteria.

The evaluation was guided by these desired characteristics for the proposed generation:

- Baseload Capacity
- Environmental Compliance
- High Reliability and Availability
- Commercially Available and Proven Technology
- Cost Effective

This report compares the technical applicability, environmental capability, plant reliability and availability, commercial availability, and cost of PC, CFB and IGCC coal-based power generation technologies for a new Basin Electric 250 MW Powder River Basin (PRB) coal-based power plant project in northeast Wyoming. This study evaluates four technology options based on the selected plant site; one PC case, one CFB case, and two IGCC cases (conventional IGCC and ultra-low emissions IGCC). Basin Electric does not consider the BACT requirement as a process that should be used to define an emission source. However, an equivalent "Top-Down" BACT Analysis was performed based on the four evaluated cases.

1.1 Preliminary Technology Assessment

A preliminary conceptual level technology assessment was conducted to address the advantages and limitations of PC, CFB and IGCC coal-based power generation technologies ~~for a new BEPC 250 MW PRB coal-based power plant project in northeast Wyoming. The~~ technology assessment did not address the specifics at each of the candidate plant sites, but instead focused on the general characteristics of the three technologies under assessment.

The assessment addressed the capability of each technology to fulfill the need of the project based on technical, environmental, commercial, economic, and regulatory and political evaluation criteria.

The assessment concluded that the PC technology was capable of fulfilling Basin Electric's need for new generation, and was recommended for the NE Wyoming Power Project. It was determined that the CFB technology met Basin Electric's need, however, it lacked demonstrated long-term operating experience on PRB coal.

The IGCC technology was judged not capable of fulfilling the need for new generation. IGCC did not meet the requirement for a high level of reliability and long-term, cost-effective, and competitive generation of power.

1.2 Technology Evaluation

In May 2005, based on a revised load forecast for Basin Electric's member cooperatives, the average annual net plant output for the new coal unit was increased to 350 MW net. This evaluation has been conducted based on the 250 MW net plant output to maintain consistency with previous PC and CFB plant designs and cost estimates developed for this plant size. Section 10 of this report discusses the impact on plant design, heat rate and cost due to the plant size increase from 250 MW to 350 MW net plant output.

SECTION 2.0

Design Basis

The design basis in this study for the proposed Dry Fork Station is described in the following sections.

2.1 GENERAL AND SITE CRITERIA

Plant Location:	Near Gillette, Wyoming
Elevation:	4,250 ft. above mean sea level
Annual Average Ambient Temperature:	44°F
Ambient Air Design Temperature:	
Summer Design:	100°F DB, 62°F WB
Condenser Cooling Water System:	Dry Air Cooled Condenser
Auxiliary Cooling Water System:	Cooling Tower w/Plate & Frame HX
Water Supply:	Well Water
Housing:	Indoor Steam Turbine Generator
	Allowance for Future Expansion
Design Life:	40 years

2.2 PLANT PERFORMANCE CRITERIA

Net Electrical Output, Design:	250 MWe (100°F @ design condenser pressure)
Net Electrical Output, Max:	275 MWe (44°F and below)
Schedule Milestones:	
Start Construction Date:	March 2007
COD Date:	January 2011
Plant Loading Profile:	Base loaded
Capacity Factor	85%
Availability Factor	90%
Primary Fuel:	Powder River Basin (PRB) Coal (see Table 2-1)
Backup Fuel for Start-up:	Natural Gas

TABLE 2-1
Dry Fork Mine Estimated Coal Quality
Basin Electric Dry Fork Station Technology Evaluation

Parameters	Estimated Coal Quality		
	Target	Minimum	Maximum
	As Received Proximate Analysis		
Heating Value (BTU/Lb)	8,045	7,800	8,300
Moisture (%)	32.06	30.5	33.8
Ash (%)	4.77	4.2	6.5
SO2 (Lb/MMBtu)	0.82	0.60	1.21
Volatile Matter (%)	30.12	28.05	32.01
Fixed Carbon (%)	33.05	31.64	34.14
	As Received Ultimate Analysis		
Carbon (%)	47.22	46.55	48.14
Hydrogen (%)	3.23	2.98	3.37
Nitrogen (%)	0.72	0.65	0.69
Chlorine (%)	< 0.1	< 0.1	< 0.1
Sulfur (%)	0.33	0.25	0.47
Oxygen (%)	11.67	10.68	13.68

Combustion Technology Description

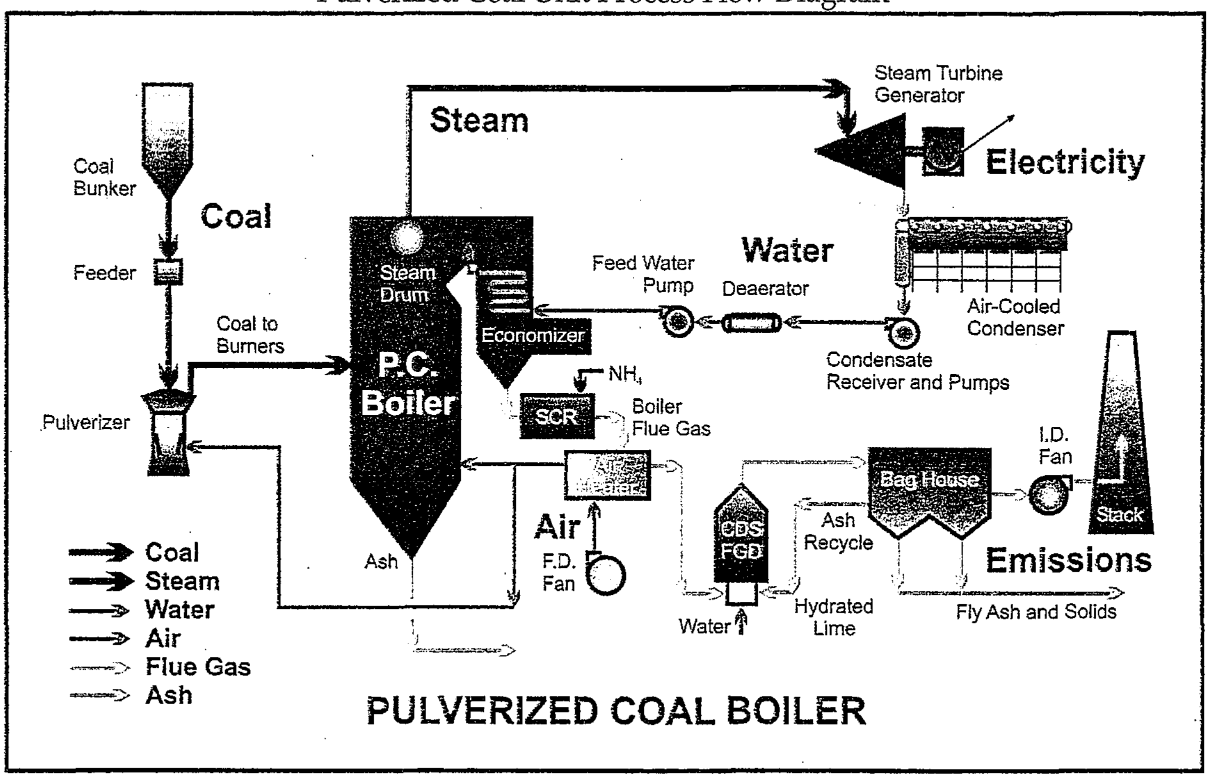
This study evaluates four technology options based on the selected plant site:

- Pulverized Coal (PC)
- Circulating Fluid Bed (CFB)
- Conventional Integrated Gasification Combined Cycle (IGCC)
- Ultra-Low Emissions Integrated Gasification Combined Cycle (IGCC)

3.1 Pulverized Coal Process Description

PC plants represent the most mature of coal-based power generation technologies considered in this assessment. Modern PC plants generally range in size from 80 MW to 1,300 MW and can use coal from various sources. Units operate at close to atmospheric pressure, simplifying the passage of materials through the plant, reducing vessel construction cost, and allowing onsite fabrication of boilers. A typical process flow diagram for a PC unit is shown in Figure 3-1.

Figure 3-1
Pulverized Coal Unit Process Flow Diagram



The concept of burning coal that has been pulverized into a fine powder stems from the fact that if the coal is made fine enough, it will burn almost as easily and efficiently as a gas.

Crushed coal from the silos is fed into the pulverizers along with air preheated to about 580°F. The hot air dries the fine coal powder and conveys it to the burners in the boiler. The burners mix the powdered coal in the air suspension with additional pre-heated combustion air and forces it out of nozzles similar in action to fuel being atomized by fuel injectors.

Combustion takes place at temperatures from 2400-3100°F, depending largely on coal rank. Steam is generated, driving a steam turbine-generator. Particle residence time in the boiler is typically 2-5 seconds, and the particles must be small enough for complete burnout to have taken place during this time. Steam generated in the boiler is conveyed to the steam turbine generator, which converts the steam thermal energy into mechanical energy. The turbine then drives the generator to produce electricity.

The boiler produces combustion gases, which must be treated before exiting the exhaust stack to remove fly ash, NO_x, and SO_2. The pollution control equipment includes either a fabric filter or ESP for particulate control (fly ash), Selective Catalytic Reduction (SCR) for removal of NO_x, and a Flue Gas Desulfurization (FGD) system for removal of SO_2. Limestone is required as the reagent for the most common wet FGD process, limestone forced oxidation desulfurization. A spray dryer FGD process, which is more commonly used on lower sulfur western coal, uses lime as the reagent and provides significant savings in water consumption over wet FGD systems. A lime or limestone storage and handling system is a required design consideration with this system.

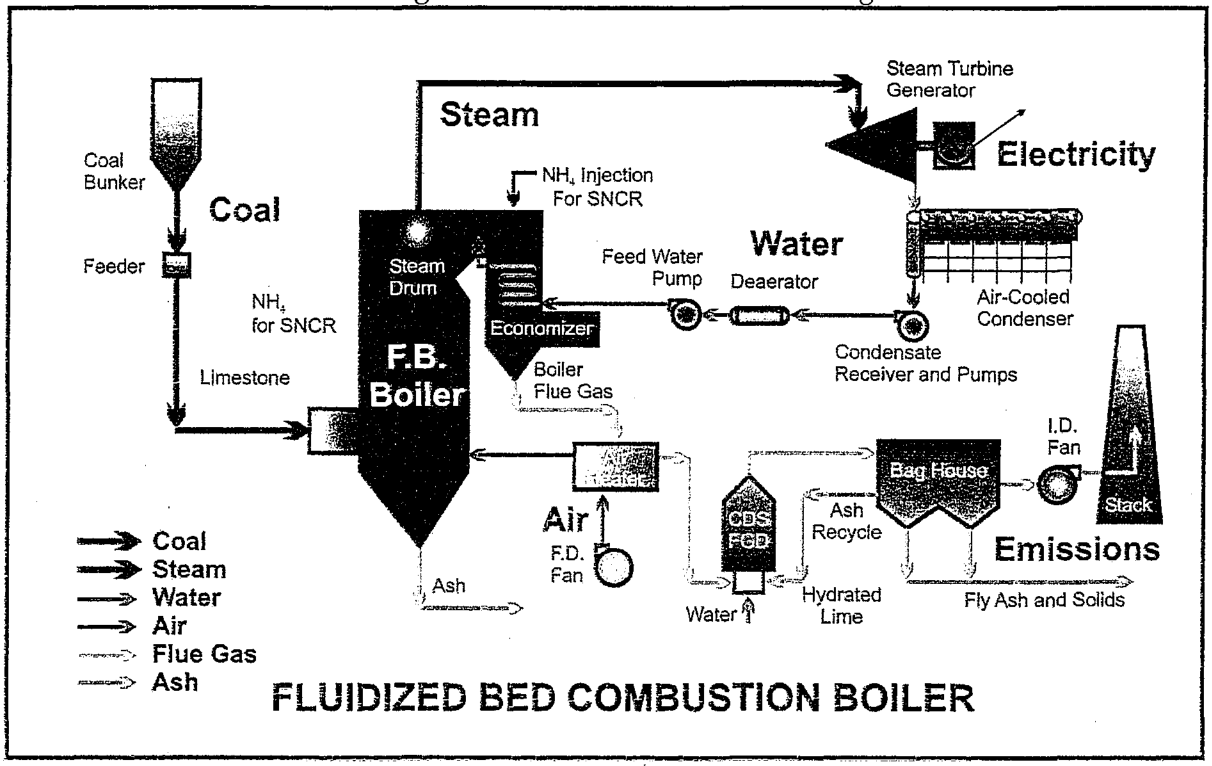
3.2 Circulating Fluidized Bed Process Description

The CFB fuel delivery system is similar to that of a PC unit, but somewhat simplified to produce a coarser material. The plant fuel handling system unloads the fuel, stacks out the fuel, crushes or otherwise prepares the fuel for combustion, and reclaims the fuel as required. The fuel is usually fed to the CFB by gravimetric feeders. The bed material is composed of fuel, ash, sand, and the sulfur removal reagent (typically limestone), also referred to as sorbent. In the CFB the fuel is combusted to produce steam. Steam is conveyed to the steam turbine generator, which converts the steam thermal energy into mechanical energy. The turbine then drives the generator to produce electricity. A typical process flow diagram for a CFB unit is shown in Figure 3-2.

CFB combustion temperatures of 1,500 to 1,600°F are significantly lower than a conventional PC boiler of up to 3,000°F which results in lower NO_x emissions and reduction of slagging and fouling concerns characteristic of PC units. In contrast to a PC plant, sulfur dioxide can be partially removed during the combustion process by adding limestone to the fluidized bed.

Circulating beds use a high fluidizing velocity, so the particles are constantly held in the flue gases, and pass through the main combustion chamber and into a particle separation device such as a cyclone, from which the larger particles are extracted and returned to the combustion chamber. Individual particles may recycle anywhere from 10 to 50 times, depending on their size, and how quickly the char burns away. Combustion conditions are relatively uniform through the combustor, although the bed is somewhat denser near the bottom of the combustion chamber. There is a great deal of mixing, and residence time during one pass is very short.

Figure 3-2
Circulating Fluid Bed Unit Process Flow Diagram



CFBs are designed for the particular coal to be used. The method is principally of value for low grade, high ash coals which are difficult to pulverize, and which may have variable combustion characteristics. It is also suitable for co-firing coal with low grade fuels, including some waste materials. The advantage of fuel flexibility often mentioned in connection with CFB units can be misleading; the combustion portion of the process is inherently more flexible than PC, but material handling systems must be designed to handle larger quantities associated with lower quality fuels. Once the unit is built, it will operate most efficiently with whatever design fuel is specified.

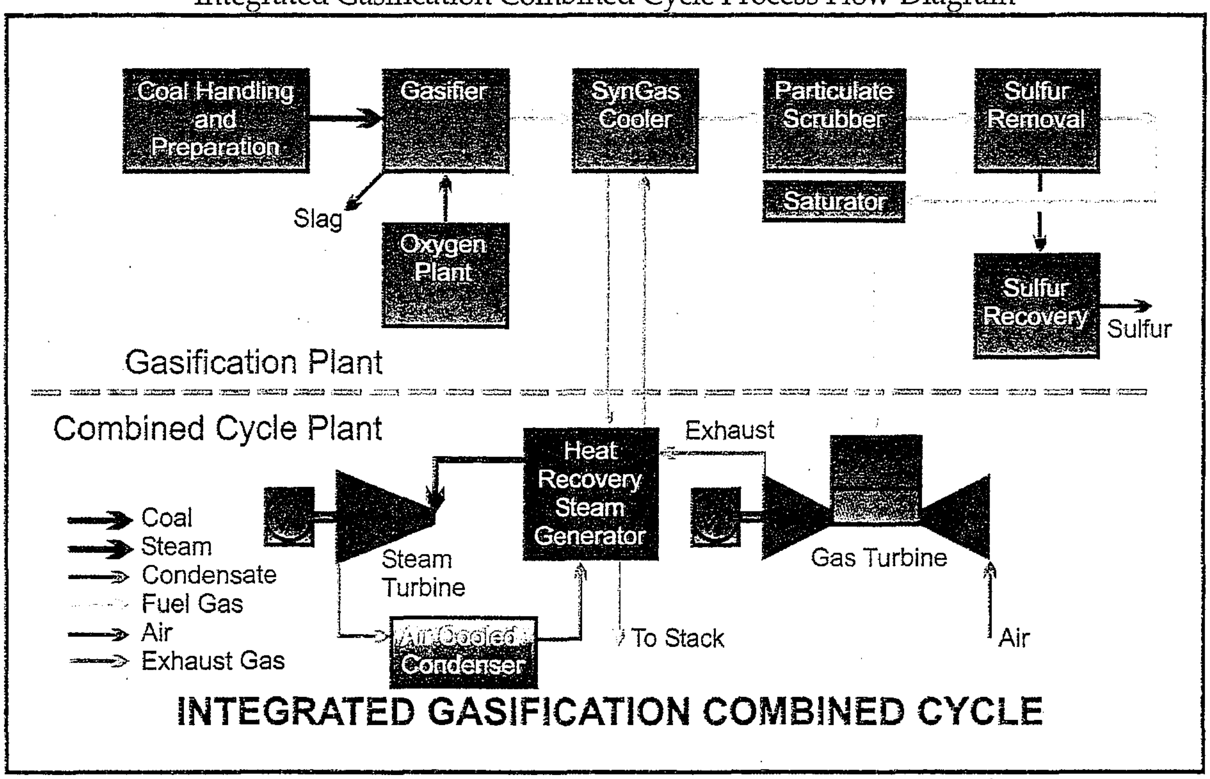
The design must take into account ash quantities, and ash properties. While combustion temperatures are low enough to allow much of the mineral matter to retain its original properties, particle surface temperatures can be as much as 350°F above the nominal bed temperature. If any softening takes place on the surface of either the mineral matter or the sorbent, then there is a risk of agglomeration or of fouling.

The CFB produces combustion gases, which must be treated before exiting the exhaust stack to remove fly ash and sulfur dioxides. NO_x emissions can be mitigated through use of selective non-catalytic reduction (SNCR) using ammonia injection, usually in the upper area of the combustor. The pollution control equipment external to the CFB includes either a fabric filter (baghouse) or electrostatic precipitator for particulate control (fly ash). A polishing FGD system may be required for additional removal of sulfur dioxides to achieve similar emission levels to PC units with FGD systems. Limestone is required as the reagent for the most common wet FGD process, limestone forced oxidation desulfurization, and also as sorbent for the fluidized bed. A spray dryer FGD process, another option for low SO2 concentration flue gas streams, uses lime as the reagent. A limestone storage and handling system is a required design consideration for CFB units. A lime storage and handling system would also be required if a lime spray dryer is used for the polishing FGD system.

3.3 IGCC Process Description

IGCC for use in coal-based power generation reacts coal with steam and oxygen or air at high temperature to produce a gaseous mixture consisting primarily of hydrogen and carbon monoxide. The gaseous mixture requires cooling and cleanup to remove contaminants and pollutants to produce a synthesis gas suitable for use in the combustion turbine portion of a combined cycle unit. The combined cycle portion of the plant is similar to a conventional combined cycle. The most significant differences in the combined cycle are modifications to the combustion turbine to allow use of a 200 to 400 Btu/SCF gas and use of steam produced via heat recovery from the raw gas in addition to that from the combustion turbine exhaust (HRSG). Specifics of a plant design are influenced by the gasification process and matching coal supply, degree of heat recovery, and methods to clean up the gas. A typical process flow diagram for an IGCC unit is shown in Figure 3-3.

Figure 3-3
Integrated Gasification Combined Cycle Process Flow Diagram



Coal gasification takes place in the presence of a controlled 'shortage' of air/oxygen, thus maintaining reducing conditions. The process is carried out in an enclosed pressurized reactor, and the product is a mixture of CO, H_2 and CO_2 (called synthesis gas, syngas or fuel gas). The sulfur present in the fuel mainly forms H_2S but there is also a small amount of carbonyl sulfide (COS). The H_2S can be more readily removed than COS in gas cleanup processes; therefore, a hydrolysis process is typically used to convert COS to H_2S. Although no NO_x is formed during gasification, some is formed when the fuel gas or syngas is subsequently burned in the combustion turbines. The product gas is cleaned and then burned with air, generating combustion products at high temperature and pressure.

Three basic gasifier designs are possible, with fixed beds (not normally used for power generation), fluidized beds and entrained flow. Fixed bed units typically use lump coal, fluidized bed units use a feed of 3-6 mm size, and entrained flow gasifiers typically use a pulverized coal slurry feed.

The IGCC demonstration plants that have been built use different process designs, and are testing the practicalities and economics of different degrees of integration. In all IGCC plants, there is a requirement for a series of large heat exchangers to cool the syngas to temperatures at which it can be cleaned. In such exchangers, solids deposition, fouling and corrosion may take place. Currently, cooling the syngas is required for conventional cleaning, and it is subsequently reheated before combustion. At Puertollano, quenching is used to cool the syngas. This is a simple, but relatively inefficient procedure, however, it avoids deposition problems, as the ash present is rapidly cooled to a solid non-sticky form. The cold gas cleaning processes used are variants of well proven natural gas sweetening processes to remove acid impurities and any sulfur present.

The syngas is produced at temperatures up to 2900°F (in entrained flow gasifiers), while the gas clean up systems which are being assessed, operate at a maximum temperature of 900-1100°F. Large heat exchangers are required, and there is the possibility of solids deposition in these exchangers which reduces heat transfer. It seems that unless it is possible to develop hot gas cleaning as a reliable procedure, the comparative economics of IGCC will remain unattractive.

3.3.1 Conventional IGCC

A Conventional IGCC unit uses chemical absorption with an amine process such as an MDEA (methyldiethanolamine) gas treatment system to remove H2S from the syngas and a sulfur plant to convert the H2S to elemental sulfur for sale or disposal. The syngas combustion turbines use water injection and low-NOx burners to control NOx emissions.

3.3.2 Ultra-Low Emissions IGCC

An Ultra-Low IGCC unit uses physical absorption with a process such as a Selexol or Rectisol (methanol solvent) gas treatment system to remove H2S from the syngas and a sulfur plant to convert the H2S to elemental sulfur for sale or disposal. The syngas combustion turbines use water injection or nitrogen dilution, low-NOx burners and downstream SCR to control NOx emissions and a downstream catalytic oxidation catalyst (Cat-Ox) to control CO emissions.

SECTION 4.0

Technical Evaluation

This section contains an evaluation of the technical capability of the PC, CFB and IGCC technologies.

4.1 Pulverized Coal

Pulverized coal has been used for large utility units for over 50 years. The technology has evolved in areas such as distributed control systems and emissions control to improve its performance.

4.1.1 Development History / Current Status

Presently, pulverized coal power is still based on the same methods started over 100 years ago, but improvements in all areas have brought coal power to be an inexpensive power source used widely today. There are thousands of units around the world, accounting for well over 90 percent of the coal-fired generation capacity. PC units can be used to fire a wide variety of coals, although it is not always appropriate for those with a high ash content.

Subcritical PC

The typical coal units of 250 MW and above that have been built in the U.S. since 1960 are subcritical PC designs using a 2400 psig/1000°F/ 1000°F single reheat steam power cycle providing a net plant efficiency (HHV)[1] of approximately 36 percent based on a bituminous coal fuel. Occasionally a 2400 psig/1050°F/ 1050°F steam cycle has been employed.

Supercritical PC

A typical commercial supercritical PC design uses a 3500 psig/1050°F/1050°F single reheat steam power cycle providing a net plant efficiency (HHV) of approximately 39 percent.

In Continental Europe, once-through boilers have been traditional, which do not require differentials between water and steam phases to operate. Due to high fuel prices in Europe, it was therefore logical for steam pressures to continue to be increased above 2400 psig in the quest for greater unit efficiency. In Japan, the Ministry of Trade and Industry encouraged a relatively early and universal change to supercritical steam conditions, and virtually all steam boiler/turbine units above 350 MW operating in Japan use supercritical steam conditions.

While the majority of coal-fired units in the U.S. have used subcritical drum boilers, a significant number of supercritical units have also been built. Early supercritical units experienced various reliability problems. Between the first commercial demonstration of the

[1] Net Plant Efficiency (HHV) is defined as the net electrical output of the plant divided by the higher heating value fuel consumption of the plant.

supercritical technology by AEP in 1956, and the mid-1970s, substantial experience was accumulated. Some of that experience was disappointing. However, most of the supercritical units built in that period continue to operate today, and many now have good availability records. Ameren, an electric utility provider in Missouri and Illinois continues to operate 1000 MW supercritical units built in 1966 and 1968. American Electric Power (AEP), an electrical utility provider to 11 states based in Columbus, Ohio, has units of 600, 800 and 1300 MW that entered service between 1968 and 1990.

4.1.2 Efficiency

A Basin Electric 250 MW PC unit would use a subcritical steam cycle design. The additional capital cost for a supercritical steam cycle is typically only justified by the efficiency improvement for PC units of 350 MW and larger. There is also a minimum 350 MW size limitation due to the first stage design of the steam turbine.

4.1.3 Operating History w/PRB Coal

Most of the PRB coal used for electricity generation is burned in PC plants. PC units experienced many problems during the initial use of PRB coals, but experience has resulted in development of PC boiler designs to successfully burn PRB coals. PC designs for PRB coal are based on the specific characteristics of the fuel such as moisture content, ash composition and softening temperature, and sulfur content.

4.1.4 PC Configuration Selected for Evaluation

The PC configuration selected for evaluation uses a conventional high dust/high temperature SCR system for NOx control and a Circulating Dry Scrubber (CDS) FGD system for SO2 control.

4.2 Circulating Fluid Bed

CFB power plants have demonstrated technical feasibility in commercial utility applications for about 20 years. The technology has evolved during that time to improve its technical performance.

4.2.1 Development History / Current Status

Study of the fluidized bed coal combustion concept began in the early 1960s. The original goal was to develop a compact "package" coal boiler that could be pre-assembled at the factory and shipped to a plant site (a lower cost alternative to the costly onsite assembly of conventional boilers). In the mid-1960s, it was realized that a fluidized bed boiler not only represented a potentially lower cost, more efficient way to burn coal, but also a much cleaner technology. The same turbulent, or "fluidizing," mixing of the coal to improve combustion also provided a way to inject sulfur-absorbing limestone to clean the coal while it burned. A 500-kilowatt fluidized bed coal combustor test plant was built in Alexandria, Virginia, in 1965. It provided much of the design data for a 30-megawatt prototype unit at the Monongahela Power Company's Rivesville, West Virginia, plant built in the mid-1970s.

The first commercially successful fluidized bed was an industrial-size atmospheric unit (equivalent to a 10-megawatt combustor) built with federal funds on the campus of Georgetown University in 1979. The Georgetown unit still operates today.

The technology progressed into larger scale utility applications due, in large part, to Federal partnership programs with industry. The Colorado-Ute Electric Association project in Nucla, CO (now operated by Tri-State Generation and Transmission Association, Inc., of Denver) was one of the early demonstrations in the Clean Coal Technology Program. From this project came significant design improvements in utility-scale atmospheric fluidized bed technology, and as a result, commercial confidence in this advanced, low-polluting combustion system picked up considerably.

In 1996, Jacksonville Electric Authority (JEA) chose to replace two older oil and gas fired units at their Northside Station with atmospheric fluidized bed combustion technology. DOE contributed more than $74 million to the project as one of the original projects under its Clean Coal Technology Program. The federal funding went to install one of the two combustors. JEA repowered the second steam turbine using the new technology with its own funding. On October 14, 2002, the utility declared the new technology to be fully operational. The two 300 MW fluidized bed systems at the Northside Station became fully operational in October, 2002. At the time they went into operation, they were the largest fluidized bed combustors ever installed in a power plant.

4.2.2 Efficiency

In the 100-200 MWe range, the thermal efficiency of CFB units may be lower than that for equivalent size PC units by a few percentage points, depending on coal quality. In CFB, the heat losses from the cyclone(s) are considerable. This results in reduced thermal efficiency, and even with ash heat recovery systems, there tend to be high heat losses associated with the removal of both ash and spent sorbent from the system. The use of a low grade coal with variable characteristics tends to result in lower efficiency, and the addition of sorbent and subsequent removal with the ash results in heat losses. It is projected that a 250 MW CFB unit for the BEPC Dry Fork project would have an efficiency similar to a PC unit.

4.2.3 Operating History w/PRB Coal

The majority of existing utility CFB units burn bituminous coal, anthracite coal waste or lignite coal. The operating history of utility CFB boilers burning PRB or other types of subbituminous coal is limited. CFB technology typically has an economic advantage only when used with high ash and/or high sulfur fuels. Therefore, bituminous coal, petroleum coke, coal waste, lignite and biomass fuels are the typical applications for CFB technology.

The two JEA 300 MW CFB demonstration units are designed to burn both bituminous coal and petroleum coke. There is a minimum coal ash content versus coal sulfur content specification for these units. The lowest specified coal sulfur content of 0.50 wt. percent corresponds to a minimum coal ash content of 12 wt. percent. Most of the PRB coals proposed for the Basin Electric Dry Fork project contain between 0.30 to 0.50 wt. percent sulfur and between 4.0 to 8.0 wt. percent ash. The Dry Fork Mine coal averages approximately 0.33 wt. percent sulfur and 4.77 wt. percent ash. Therefore, none of these PRB coals would be an acceptable fuel for the JEA CFB units based on sulfur and ash content unless they were blended with a higher sulfur and/or ash fuel.

PRB coals may also have a tendency to produce small particle size (fine) fly ash that makes it more difficult to maintain the required bed volume in a CFB unit. Therefore, additional quantities of inerts such as sand and limestone may be required for a CFB unit burning low sulfur/low ash PRB coals.

A joint Colorado Springs Utilities / Foster Wheeler 150 MW Advanced CFB demonstration project at the Ray D. Nixon Power Plant south of Colorado Springs was proposed and accepted by DOE NETL in 2002 as part of the federal Clean Coal Power Initiative (CCPI). DOE agreed to a $30 million cost share of the $301.5 million project. The next generation CFB unit would be designed to burn PRB coal and PRB blended with coal waste, biomass and petroleum coke. However, Colorado Springs Utilities and Foster Wheeler cancelled and withdrew from the CCPI project in 2003.

4.2.4 CFB Configuration Selected for Evaluation

The CFB configuration selected for evaluation uses a Selective Non-Catalytic Reduction (SNCR) system for NOx control and a CDS FGD system for SO2 control.

4.3 Integrated Gasification Combined Cycle

IGCC has been demonstrated in a few commercial-scale facilities. A variety of coals have been gasified, the resulting gases have been cleaned up to allow use in combustion turbines, and electricity has been generated. However, the capital cost and performance in a number of areas have not been as attractive as planned. The troublesome areas for IGCC have included high-temperature heat recovery and hot gas cleanup.

An important part of achieving an attractive heat rate is generation of high pressure and temperature steam from the high-temperature raw gas generated by gasifying coal. The temperature of the raw gas is dependent on the gasification process and the coal. Slagging gasifiers, such as the Texaco process, typically generate gases in the 2500 to 2800°F range. These high-temperature gases containing corrosive compounds, such as H_2S, create a very demanding environment for the generation of high pressure and temperature steam. The alternative of not recovering the heat in the raw gas, such as direct quenching of the gas, results in lower efficiencies.

It is also attractive from an efficiency perspective to provide clean gas to the combustion turbine at an elevated temperature without cooling and reheating, hence the desire to use hot gas cleanup. Again, this demanding service has not been reliably demonstrated in a commercial application, resulting in less efficient approaches being used for current plants.

The main incentive for IGCC development has been that units may be able to achieve higher thermal efficiencies than PC plants, and be able to match the environmental performance of gas-fired plants. However, the thermal efficiencies of new PC plants using superheated steam have also increased as has their environmental performance.

4.3.1 Development History / Current Status

IGCC has been under development since the 1980s. A number of demonstration units, around 250 MWe size are being operated in the USA and Europe. Table 4-1 at the end of this section lists the commercial scale IGCC plants that have been built and their current status. Most of the IGCC units have used entrained flow gasifiers and are oxygen blown, but one unsuccessful demonstration unit (Pinion Pine IGCC) was based on an air-blown fluidized bed gasifier. The two plants currently operating in the U.S. are the 262 MW PSI/Global Energy Wabash River IGCC in Indiana and the 250 MW Tampa Electric Polk IGCC in Florida. The 253 MWe unit at Buggenum in The Netherlands, started up in 1993. The largest unit is located at Puertollano in Spain with a capacity of 318 MW.

All of the current coal-fueled IGCC demonstration plants are subsidized. The U.S. plants are part of the DOE Clean Coal Program, and the European plants are part of the Thermie Programme. The DOE has partially funded the design and construction of the U.S. plants, as well as the operating costs for the first few years. The Wabash River plant was a repowering project, but from the point of view of demonstrating the viability of various systems, it is effectively a new plant, even though tied to an existing steam turbine. The Cool Water and Louisiana Gasification Technology Inc (LGTI) projects were the first commercial-scale IGCC projects constructed in the United States, and were constructed with guaranteed price support from the U.S. Synthetic Fuels Corporation; both projects were shut down once the duration of the price guarantee period expired.

4.3.2 Operating History w/PRB Coal

The only commercial size IGCC demonstration plant that has operated with PRB coal fuel was the 160 MWe Dow Chemical Louisiana Gasification Technology, Inc. (LGTI) plant in Plaquemine, LA. This plant used an oxygen blown E-Gas entrained flow gasifier and is reported to have operated successfully from 1987 to 1995. The plant is now shutdown.

The Power Systems Development Facility (PSDF), located near Wilsonville, Alabama, is a large advanced coal-fired power system pilot plant. It is a joint project of DOE NETL, Southern Company and other industrial participants. The Haliburton KBR Transport Reactor was modified from a combustor to coal gasifier operation in 1999. The initial gasification tests have concentrated on PRB coals because their high reactivity and volatiles were found to enhance gasification. The highest syngas heating values were achieved with PRB coal, since PRB coal is more reactive than bituminous coals.

Southern Company, Orlando Utilities Commission, and Kellogg Brown and Root, were recently selected by DOE NETL for co-funding in the Round 2 Clean Coal Power Initiative (CCPI) solicitation. They propose to construct and demonstrate operation of a 285 MW coal-based transport gasifier plant in Orange County, Florida. The proposed facility would gasify sub-bituminous coal in an air-blown integrated gasification combined cycle power plant based on the KBR Transport Gasifier. Southern Company estimated the total cost for the project at $557 million ($1954/MW) and requested $235 million of DOE funds to support the project.

4.3.3 Efficiency

The driving force behind the development of IGCC is to achieve high thermal efficiencies together with low levels of emissions. It is hoped to reach efficiencies of over 40 percent, and possibly as high as 45 percent with IGCC. Higher efficiencies are possible when high gas inlet temperatures to the gas turbine can be achieved. At the moment, the gas cleaning stages for particulates and sulfur removal can only be carried out at relatively low temperatures, which restricts the overall efficiency obtainable.

4.3.4 IGCC Configurations Selected for Evaluation

The two IGCC configurations selected for evaluation represent a conventional IGCC unit and an ultra-low emissions IGCC unit.

The conventional IGCC unit uses an MDEA gas treatment system to reduce H2S to approximately 25 ppmv in the syngas sent to the combustion turbine generators (CTGs) for SO2 control, and water injection with low-NOx burners in the CTGs for NOx control.

The ultra-low emissions IGCC unit uses a Selexol gas treatment system to reduce H2S to approximately 10 ppmv in the syngas sent to the CTGs for SO2 control, water injection with low-NOx burners in the CTGs and an SCR system for NOx control, and a catalytic oxidation catalyst (Cat-Ox) system for CO control.

TABLE 4-1
Commercial Scale IGCC Power Plants
Basin Electric Dry Fork Station Technology Evaluation

Plant Name	Plant Location	Net Output (MWe)	Feedstock	Gasifier Design	Gas Cleanup	Power Island	Net Plant Heat Rate (Btu/kWh)	Operation Status
Texaco Cool Water	Daggett, CA	96	Low S & High S Bituminous Coal	O2 Blown Texaco Entrained Flow (2500°F, 600 Psig)	Cold H2S and Ash Removal	GE 7FE CTG / STG	11,300 (HHV Basis)	1984-1988 (shutdown)
Dow Chemical / Destec LGTI	Plaquemine, LA	160	Subbituminous PRB Coal	O2 Blown E-Gas Entrained Flow (2700°F, 400 Psig)	Cold H2S and Ash Removal	West. 501 CTG / STG	10,500 (HHV Basis)	1987-1995 (shutdown)
Sierra Pacific Pinon Pine	Tracy Station, Reno, NV	107	Low S Western Bituminous Coal	Air Blown Pressurized KRW fluid bed (1800°F, 325 Psig)	Hot H2S and Ash Removal	GE 6FA CTG / STG	8,390 (HHV Basis)	1998-2000 (never successfully started-up)
Tampa Electric Polk Plant	Polk County, FL	250	High S Bit. Coal & Petroleum Coke	O2 Blown Chevron-Texaco Entrained Flow (2500°F, 375 Psig)	Cold H2S and Ash Removal	GE 7FA CTG / STG	9,650 (HHV Basis)	1996-Present
PSI / Global Energy Wabash River	West Terre Haute, IN	262	High S Bit. Coal & Petroleum Coke	O2 Blown E-Gas Entrained Flow (2600°F, 400 Psig)	Cold H2S and Ash Removal	GE 7FA CTG / STG	8,900 (HHV Basis)	1995-Present
NUON/Demcolec / Willem-Alexander	Buggenum, The Netherlands	253	Bituminous Coal	O2 Blown Shell Entrained Flow (2600°F, 400 Psig)	Cold H2S and Ash Removal	Siemens V94.2 CTG / STG	8,240 (HHV Basis)	1994-Present
ELCOGAS / Puertollano	Puertollano, Spain	318	50%/50% Coal & Petroleum Coke Mix	O2 Blown Prenflo Entrained Flow (2900°F, 400 Psig)	Cold H2S and Ash Removal	Siemens V94.3 CTG / STG	8,230 (HHV Basis)	1998-Present

SECTION 5.0

Environmental Evaluation

Environmental impacts associated with PC units include air emissions, water/wastewater discharge issues, and solid waste disposal. Impacts are minimized by utilizing air pollution control equipment, wastewater pretreatment controls, and the potential reuse of ash.

Environmental impacts associated with a CFB coal unit include air emissions, water/wastewater discharge issues, and solid waste disposal. Impacts are minimized by utilizing air pollution control equipment, wastewater pretreatment controls, and the potential reuse of ash. A CFB design does have the advantage of burning a wider range of fuels including waste materials such as petroleum coke or renewable biomass.

The overall environmental impacts from an IGCC unit would be between those of a natural gas-fired combustion turbine combined cycle unit and a PC unit. Environmental impacts would include air emissions, water/wastewater discharge, and solid waste disposal.

5.1 Air Emissions

Pulverized Coal

A PC unit for the Dry Fork Station will use low-NO_x burners and SCR for NO_x control, CDS FGD for SO_2 control, and a fabric filter for particulate control. There would be PM_{10} emissions from coal, ash, and lime material handling operations. There would also be other sources of air emissions from miscellaneous support equipment such as diesel or natural gas-fired emergency generators, fire pumps, and the installation of a natural gas-fired auxiliary boiler. A case-by-case, maximum achievable control technology (MACT) analysis would be required for trace metals in the coal, organics, and acid gases.

Circulating Fluid Bed

Combustion takes place at temperatures from 1500-1600°F, resulting in reduced NO_x formation compared with a PC unit. While the air emissions exiting a CFB boiler (especially NO_x, SO_2, and CO) are lower than a conventional PC boiler, the final stack emissions would be similar based on the use of add-on control equipment. Current BACT would require SNCR for NO_x control, limestone injection in the furnace for SO_2 control, and a fabric filter for particulate control. A polishing CDS FGD system would also be required for additional SO_2 control.

There would be PM_{10} emissions from coal, ash, lime and limestone material handling operations. There would also be other sources of air emissions from miscellaneous support equipment, such as diesel or natural gas-fired emergency generators, fire pumps, and the installation of a natural gas-fired auxiliary boiler. A case-by-case MACT analysis would be required for trace metals in the coal, organics, and acid gases.

Integrated Gasification Combined Cycle

An IGCC plant has the potential for reduced emissions of SO_2, NO_x, Hg and particulates compared to levels produced by conventional PC and CFB units. SO_2 removal up to 98 to 99 percent and Hg removal of approximately 90 percent is possible in the gas treatment system downstream of the gasifier. Particulates will be removed to levels approaching natural gas fired combustion turbines. NO_x emissions from the gas turbines should be similar to emissions from natural gas fired combustion turbines. Based on a BACT analysis, additional controls may be required including SCR for NO_x reduction and catalytic oxidation for CO reduction.

There would be PM_{10} emissions from coal and ash material handling operations. There would also be other sources of air emissions from the IGCC process from the syngas/natural gas-fired auxiliary boiler used to dry the PRB coal, flaring of treated or untreated syngas during plant startups, shutdown and upsets, and from miscellaneous support equipment such as diesel or natural gas emergency generators and fire pumps.

The reported annual SO2 and NOx emission rates for the two U.S. IGCC demonstration plants are shown in Figures 5-1 and 5-2.

Figure 5-1

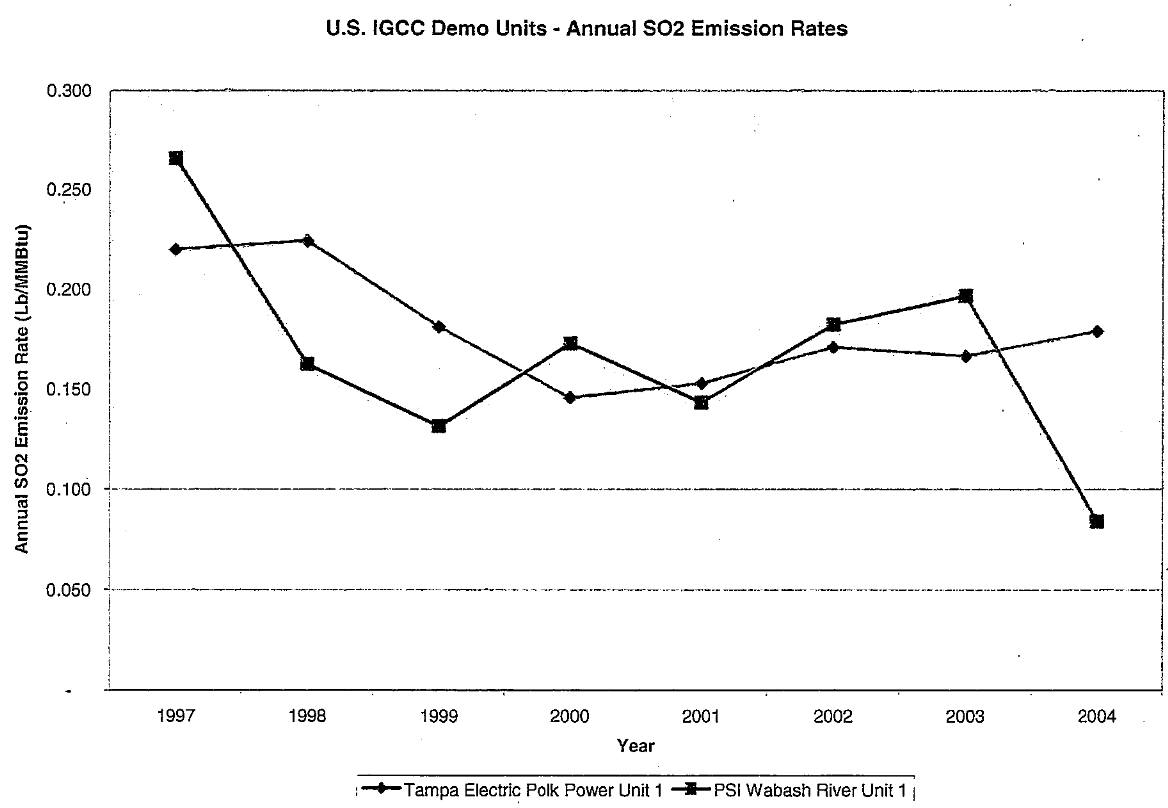


Figure 5-2

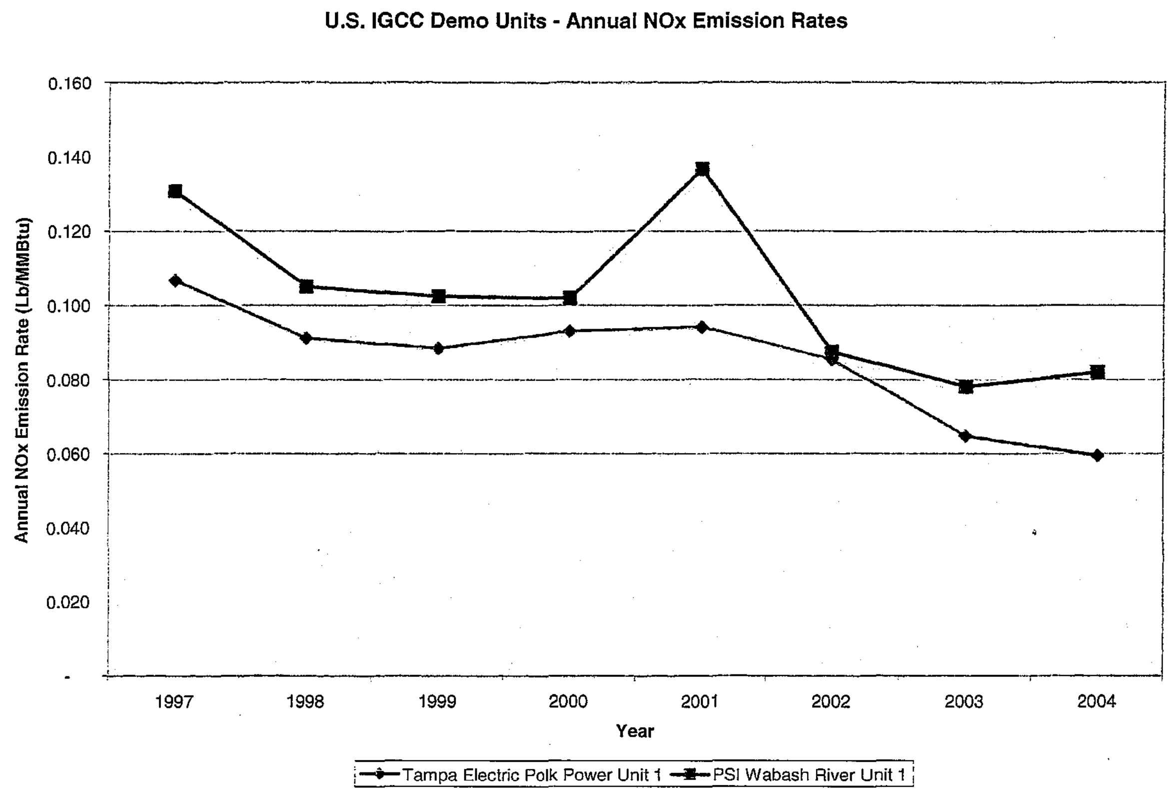


Table 5-1 compares the proposed Dry Fork Station PC emission rates with the current annual emission rates from existing CFB commercial plants and from existing U.S. IGCC demonstration plants.

TABLE 5-1
Comparison of Coal Combustion Technology Emission Rates
Basin Electric Dry Fork Station Technology Evaluation

	Emission Rates for Coal Combustion Technologies (Lb/MMBtu)		
Pollutant	**PC (Potential BACT)**	**CFB (Existing U.S. Commercial Plants)**	**IGCC (Existing U.S. Demonstration Plants)***
SO_2	0.10	0.10	0.17
NO_x	0.07	0.09	0.09
PM_{10}**	0.019	0.019	0.011
CO	0.15	0.15	0.045
VOC	0.0037	0.0037	0.0021

Notes:
* PSI Energy Wabash River Station and TECO Polk Power Station Existing IGCC Demonstration Plants.
**PM_{10} includes filterable and condensable portions.

5.2 Water/Wastewater

Pulverized Coal

Liquid wastes would include boiler feed water (BFW) blowdown, auxiliary cooling tower blowdown, and chemicals associated with water treatment. Dry cooling and zero liquid discharge systems will be used to reduce overall water consumption and discharge. A groundwater protection permit will be required if evaporation ponds are included in the plant design. Stormwater discharge permits and stormwater pollution prevention plans (SWPPP) would be required. Spill Prevention, Control, and Countermeasures (SPCC) plans may also be required.

Circulating Fluid Bed

Similar to a PC plant, CFB plant liquid wastes would include BFW blowdown, auxiliary cooling tower blowdown, and chemicals associated with water treatment. Dry cooling and zero liquid discharge systems will be used to reduce overall water consumption and discharge. A groundwater protection permit will be required if evaporation ponds are included in the plant design. Stormwater discharge permits and stormwater pollution prevention plans (SWPPP) would be required. Spill Prevention, Control, and Countermeasures (SPCC) plans may also be required.

Integrated Gasification Combined Cycle

An IGCC unit for the Dry Fork project would have two primary liquid effluents. The first is blowdown from the BFW purification system, although the blowdown will be less compared to a PC or CFB unit since the steam cycle in an IGCC plant typically produces less than 40 percent of the plant's power. However, BFW makeup may be the same as, or even larger, than a PC or CFB based plant of comparable output, even if it is well designed, operated and maintained. A coal gasification process may consume significant quantities of BFW in tap purges, pump seals, intermittent equipment flushes, syngas saturation for NO_x control, and direct steam injection into the gasifier as a reactant and/or temperature moderator.

The second liquid effluent from an IGCC plant is process water blowdown. This process water blowdown is typically high in dissolved solids and gases along with the various ionic species washed from the syngas such as sulfide, chloride, ammonium and cyanide. The Wabash River IGCC plant installed an add-on mechanical vapor recompression (MVR) system in 2001 to better control arsenic, cyanide and selenium in the wastewater stream.

As with the PC and CFB power units, dry cooling and zero liquid discharge systems will be used to reduce overall water consumption and discharge. The Tampa Electric Polk IGCC plant treats process water blowdown with ammonia stripping, vapor compression concentration, and crystallization to completely eliminate process water discharge.

Liquid wastes would also include auxiliary cooling tower blowdown and chemicals associated with water treatment. A groundwater protection permit will be required if evaporation ponds are included in the plant design. Stormwater discharge permits and stormwater pollution prevention plans (SWPPP) would be required. Spill Prevention, Control, and Countermeasures (SPCC) plans may also be required.

5.3 Solid Waste

Pulverized Coal

Solid wastes include bottom ash from the boiler, and combined dry FGD and fly ash solid waste from the fabric filter. Disposal of these wastes is a major factor in plant design and cost considerations.

Circulating Fluid Bed

Solid wastes include boiler bed ash, and combined dry FGD and fly ash solid waste from the fabric filter. Since limestone is injected into the CFB boiler for SO2 removal, there will be additional CaO, $CaSO_4$ and $CaCO_3$ present in the bed and fly ash. There may be a high free lime content, and leachates will be strongly alkaline. Carbon-in-ash levels are higher in CFB residues that in those from PC units. As with PC fired units, disposal of these wastes is a major factor in plant design and cost considerations.

Integrated Gasification Combined Cycle

IGCC power generation has demonstrated reduced environmental impact compared to PC and CFB plants in terms of solid waste quantities and the potential for leaching of toxic substances into the soil and groundwater. The largest solid waste stream produced by an IGCC using an entrained bed gasifier is slag. This type of gasifier operates above the fusion temperature of the coal ash, producing a black, glassy, sand-like slag material that is a potentially marketable byproduct. Leachability data obtained from different entrained-bed gasifiers has shown that this gasifier slag is highly non-leachable. The slag may be suitable for the cement industry, asphalt production, construction backfill and landfill cover operations.

Most gasification processes also produce a smaller amount of char (unreacted fuel) and/or fly ash that is entrained in the syngas. This material is typically captured and recycled to the gasifier to maintain high carbon conversion efficiency and to convert the fly ash into slag to eliminate fly ash disposal.

The other large volume byproduct produced by IGCC plants is elemental sulfur or sulfuric acid, both of which can be sold to help offset plant operating costs. This contrasts with a PC or CFB unit with a dry or semi-dry lime FGD System, which recovers sulfur as dry spent sorbent mixed with the fly ash. Spent sorbent and fly ash must typically be disposed of as waste materials in an appropriate landfill.

SECTION 6.0

Reliability Evaluation

6.1 Annual Availability and Capacity Factors

Both PC and CFB technologies are considered to be mature and are used for baseload power plants. The overall plant availability of well maintained baseload PC and CFB units is approximately 90 percent. All four of the demonstration IGCC plants experienced very low availability during their early years of operation. The availability improved after design and operation changes were made to each facility, however, their current annual availability is still lower than what can be achieved with PC and CFB units.

Capacity factor measures the amount of electricity actually produced compared with the maximum output achievable. The overall plant capacity factor for well maintained baseload PC and CFB units is approximately 85 percent. All four of the demonstration IGCC plants continue to experience low capacity factors compared to baseload PC and CFB units. The reported annual availability and capacity factors for the two U.S. IGCC demonstration plants are shown in Figures 6-1 and 6-2. Data for some years was not available.

Figure 6-1

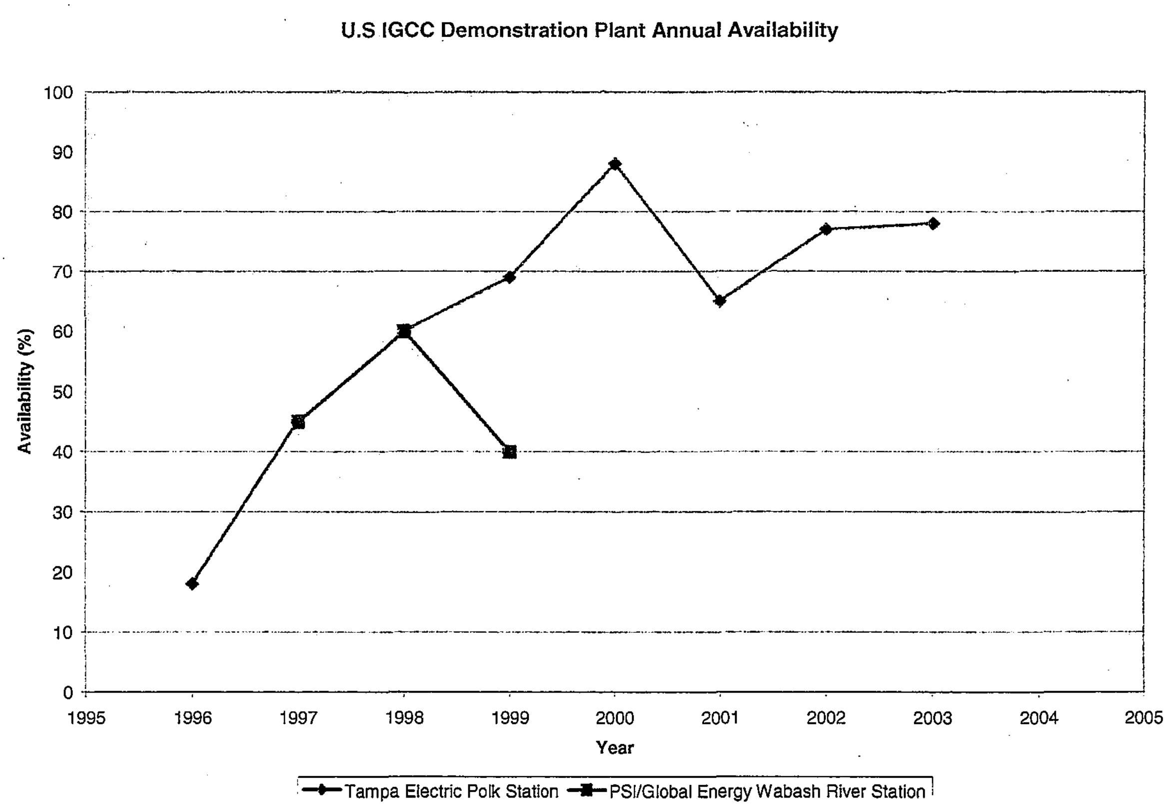
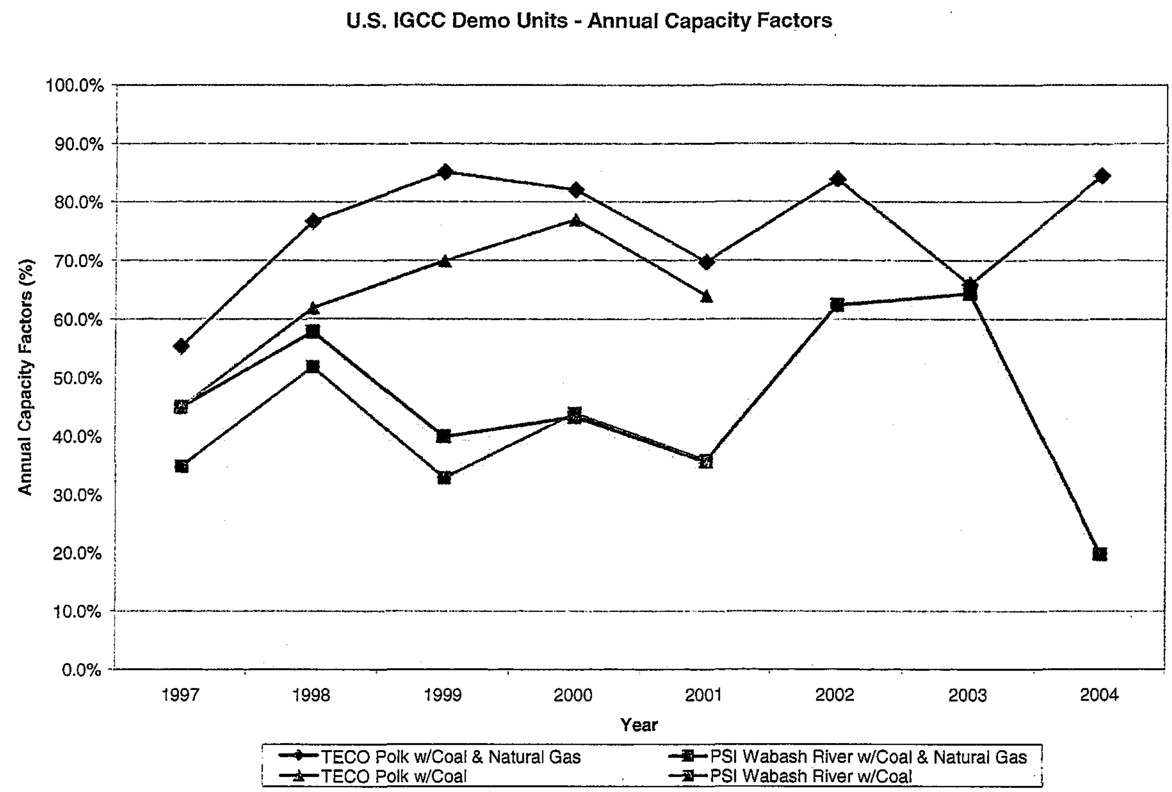


Figure 6-2



6.2 TECO Polk Power Station IGCC

The Polk IGCC Power Plant began commercial operation in September 1996. Key availability factors reported by Tampa Electric are summarized in Table 6-1. Availability is defined by Tampa Electric in their published papers and reports as the percent of time during each period that the unit was in service or in reserve shutdown.

TABLE 6-1
TECO Polk Power Station IGCC Availability

Year	Air Separation Unit (ASU)	Gasification Island	Combined Cycle Power Block	Total Plant
1996	N/A*	N/A	N/A	18%
1997	N/A	N/A	55%	45%
1998	N/A	N/A	87%	60%
1999	N/A	N/A	92%	69%
2000	N/A	N/A	87%	88%
2001	N/A	N/A	91%	65%
2002	96%	77%	94%	77%
2003	95%	78%	80%	78%

* N/A – Not Available
Source: Presentation at the 2003 Gasification Technologies Conference entitled "Polk Power Station – 7th Commercial Year of Operation" by John McDaniel and Mark Hornick.

6.3 PSI Wabash River Power Station IGCC

The Wabash River 262 MW IGCC Power Plant began commercial operation in late 1995. Key IGCC plant availability and gasification island forced outage rates reported by PSI are summarized in Table 6-2.

TABLE 6-2
PSI Wabash River IGCC Availability and Gasification Island Forced Outage Rate
Basin Electric Dry Fork Station Technology Evaluation

Year	Availability		Forced Outage Rate
	Gasification Island	Total Plant	Gasification Island
1997	N/A*	45	N/A
1998	N/A	60	N/A
1999	N/A	40	N/A
2000	73.3	N/A	18
2001	72.5	N/A	22
2002	78.7	N/A	11**
2003	74	N/A	17.5

* N/A – Not Available
** Estimated on partial year data
Source: Presentation at the 2002 and 2003 Gasification Technologies Conferences entitled "Operating Experience at the Wabash River Repowering Project" by Clifton Keeler.

6.4 NUON Buggenum Power Station IGCC

The Buggenum IGCC Power Plant started operation in 1994. It is a 250 MW plant located in the Netherlands. Key availability factors reported by NUON are summarized in Tables 6-3. In addition to burning coal, other types of fuel are being explored including wood, sewage sludge, coffee, rice and chicken litter, with varying degrees of success.

TABLE 6-3
NUON Buggenum Power Station IGCC Availability
Basin Electric Dry Fork Station Technology Evaluation

Year	Gasification Island	Combined Cycle Power Block
1999	45	N/A
2000	50	N/A
2001	N/A*	N/A
2002	67.3	89.3
2003	64.6	94.8

* N/A – Not Available
Source: Presentation at the 2000 and 2003 Gasification Technologies Conference entitled "Operating Experience at the William Alexander Centrale" by J.Th.G.M. Eurlings and Carlo Wolters, respectively.

6.5 Elcogas Puertollano Power Station IGCC

The Puertollano 335 MW IGCC Power Plant had its first 100 hours of continuous operation in August 1999. Key availability and forced outage rates reported by Elcogas are summarized in Tables 6-4 and 6-5.

TABLE 6-4
Elcogas Puertollano Power Station IGCC Availability
Basin Electric Dry Fork Station Technology Evaluation

Year	Air Separation Unit (ASU)	Gasification Island	Combined Cycle Power Block	Total Plant	Comments
2000	87.5	65.9	70.6	N/A	
2001	N/A*	71.5**	83.9	59.6	
2002	91.4	74.9	85.5	63.7	
2003	86.7	85.7	64.3	51.9	

* N/A – Not Available

** Includes ASU and ASR
Source: Presentations at the 2001 and 2003 Gasification Technologies Conference by Ignacio Mendez-Vigo.

TABLE 6-5
Elcogas Puertollano Power Station IGCC Forced Outage Rate
Basin Electric Dry Fork Station Technology Evaluation

Year	Air Separation Unit (ASU)	Gasification Island	Combined Cycle Power Block	Total Plant	Comments
2000	11.4	33.8	3.1	N/A	
2001	N/A*	26.7	13.4	36.9	
2002	2.3	14.7	3.3	25	
2003	5.4	7.9	5.1	22.6	

* N/A – Not Available

Source: Presentations at the 2001 and 2003 Gasification Technologies Conference by Ignacio Mendez-Vigo.

SECTION 7.0

Commercial Availability

PC technology is available commercially, with a long history of being the technology of choice for large base-load utility units. The CFB technology is also available commercially, but the largest CFB units in operation are approximately 300 MW in size. The CFB boiler suppliers indicate a willingness to provide larger units with full commercial guarantees.

Current and near-term IGCC plants must be viewed as still under development, and not yet delivering the cost and performance to be economically attractive. Current IGCC plants are providing good information about the technology, but not demonstrating the necessary cost of electricity to expect the technology to be available commercially in time frame to support Basin Electric's needs.

7.1 Number/Quality of Suppliers

Both PC and CFB based coal-fired power plant technologies are offered commercially on a turnkey basis by some of the larger suppliers such as Bechtel and Mitsubishi. In addition, engineering/boiler vendor/contractor consortiums will also offer these types of plants on a turnkey basis. In contrast, IGCC plants are still considered to be high risk ventures and are not currently offered on a turnkey basis. A General Electric and Bechtel partnership is developing a 600 MW standard design based on the ChevronTexaco entrained bed gasifier with an eastern bituminous coal fuel. A ConocoPhillips and Fluor partnership is also developing a 600 MW standard design based the E-Gas entrained bed gasifier with an eastern bituminous coal fuel. Both consortiums plan to offer turnkey systems in the future based on the standard plant designs. There are no turnkey IGCC systems available for a 250 MW IGCC plant based on PRB coal fuel.

7.2 Availability of Process, Performance and Emission Guarantees

PC and CFB units are available commercially with strong, financially backed process, performance and emission guarantees on a turnkey basis, or from the individual equipment suppliers. These types of project guarantees are not currently available for IGCC plants on a turnkey basis due to their early development status and limited commercial experience.

7.3 Availability of Financing Alternatives

Project financing is available for both PC and CFB based power plants. The lack of adequate developmental and project financing has been a major challenge to the deployment of IGCC power plants. The significant underlying causes include the following items:

- Perceived low rate of availability at IGCC projects in early years of operation resulting in substantially lower NPVs for that period.

- Uncertain capital funding needs of IGCC projects.
- Lack of guarantees for overall performance of the IGCC power units by plant designers, equipment suppliers and construction companies.
- Perceived need to finance IGCC power plants with government subsidies.
- Technical and business risk related to IGCC plant development. (Note that members of the John F. Kennedy School of Government of Harvard University, acknowledging that risk is a barrier to IGCC plant development, have recently proposed a "3Party Covenant" whereby the Federal Government provides loan guarantees which allow lower cost financing, state public utility commissions provide guarantees that output can be sold even if it is not the lowest-cost resource, and equity investors provide project financing based on the federal and state guarantees).

SECTION 8.0

Economic Evaluation

8.1 Economic Criteria

The major economic criteria used for the cost evaluation of the PC, CFB, Conventional IGCC and Ultra-Low Emission IGCC cases are listed in Table 8-1.

TABLE 8-1
Coal Plant Economic Evaluation Criteria
Basin Electric Dry Fork Station Technology Evaluation

Criteria	PC	CFB	Conventional IGCC	Ultra-Low Emission IGCC	Comments
Net Plant Output (MW)	273 MW	273 MW	273 MW	273 MW	Annual Average
Net Plant Heat Rate (Btu/kW-Hr)	10,500	10,800	10,500	10,500	Annual Average
Annual Plant Capacity Factor (%)	85% Coal	85% Coal	15% Natural Gas, 70% Coal	15% Natural Gas, 70% Coal	
Interest Rate (%)	6.0%	6.0%	8.0%	8.0%	Higher rate for IGCC due to risk
Discount Rate (%)	6.0%	6.0%	6.0%	6.0%	
Capital Cost Recovery Period (Years)	42 years	42 years	42 years	42 years	
Plant Economic Life (Years)	42 years	42 years	42 years	42 years	
Fixed O&M Cost ($/kW-Yr)	38.33	34.50	50.00	52.50	
Non-Fuel Variable O&M Costs ($/kW-Hr)	0.0027	0.0025	0.0020	0.0021	
Coal Cost ($/MMBtu)	0.35	0.35	0.35	0.35	
Natural Gas Cost ($/MMBtu)	7.50	7.50	7.50	7.50	

8.2 Economic Analysis Summary

The overnight capital costs and life cycle economic analysis for the PC, CFB, Conventional IGCC and Ultra-Low Emission IGCC cases is shown in Table 8-2. The net present value (NPV) for the PC, CFB, Conventional IGCC and Ultra-Low Emission IGCC cases was calculated based on the 6.0 percent discount rate and annual cash flows for a plant economic life of 42 years.

TABLE 8-2
Economic Analysis Summary for Combustion Technology Options
Basin Electric Dry Fork Station Technology Evaluation

Costs	Cost ($ Million)			
	PC	**CFB**	**Conventional IGCC**	**Ultra-Low Emission IGCC**
CAPITAL COST	**482**	**497**	**720**	**756**
FIRST YEAR O&M COST				
Fixed O&M Cost	10.7	9.6	13.9	14.6
Non-Fuel Variable Cost	5.6	5.2	4.1	4.4
Coal Cost	7.6	7.8	6.5	6.5
Natural Gas Cost	0.0	0.0	24.7	24.7
TOTAL FIRST YEAR OPERATING COST	**23.9**	**22.6**	**49.3**	**50.2**
FIRST YEAR DEBT SERVICE	**31.7**	**32.6**	**60.0**	**63.0**
TOTAL FIRST YEAR COST	**55.6**	**55.3**	**109.2**	**113.1**
Net Present Value (NPV)	**961**	**950**	**1,982**	**2,046**
	Incremental Control Cost			
Total Pollutant Emissions (Tons/Yr)	3,657	3,981	1,491	804
Incremental Pollutants Removed (Tons)	Base	-324	2,166	2,853
Incremental First Year Control Cost ($/Ton Pollutants Removed)	Base	987	24,767	20,173

* Based on SO2, NOx, CO, VOC and PM pollutants removed.

The total first year cost for the PC case is $55.6 Million versus $55.3 Million for the CFB case. The higher CFB Unit annual debt service is offset to a greater degree by the lower annual fixed O&M and non-fuel variable cost compared to a PC Unit. The total first year cost for the Conventional IGCC and Ultra-Low Emission IGCC cases are $109.2 Million and $113.1 Million, respectively.

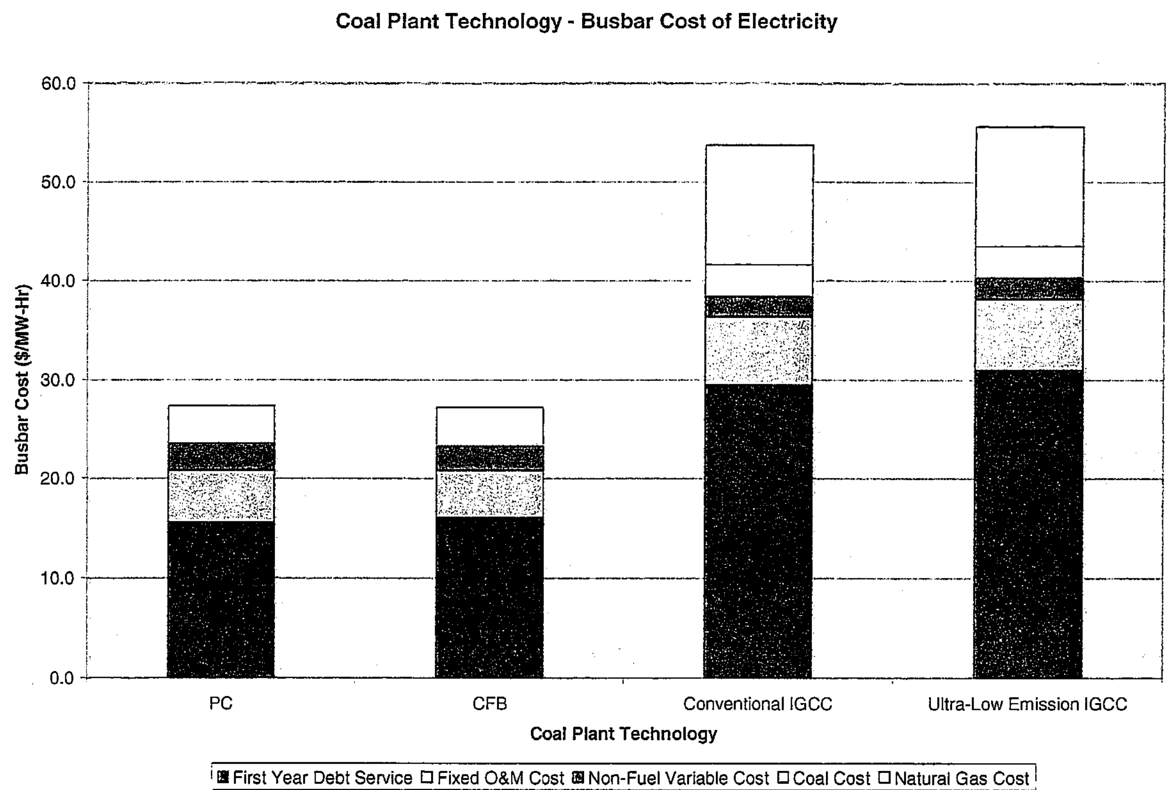
The NPV for the PC case is $961 Million versus $950 Million for the CFB case over the 42 year plant economic life. The NPV for the Conventional IGCC and Ultra-Low Emission IGCC cases is $1.98 Billion and $2.05 Billion, respectively.

The largest life cycle cost driver for all of the four cases is the debt service for the capital cost of the plant. The annual debt service cost was calculated based on financing 100 percent of the plant capital cost for 42 years at an annual interest rate of 6.0 percent for the PC and CFB cases and 8.0 percent for the IGCC cases. The interest rate for the IGCC cases is higher due to the greater project risk for an IGCC plant.

Besides capital cost and annual debt service, the other large cost differential between the PC/CFB cases and the two IGCC cases is the natural gas usage. Both PC and CFB are mature technologies that can meet the 85 percent annual capacity factor for the project. IGCC technology has not demonstrated over 70 percent annual capacity factor, and must use natural gas as a secondary fuel for the gas turbines to make up the 15 percent annual capacity factor difference (to meet the 85 percent annual capacity factor for the project).

A comparison of the first year busbar cost of electricity for the four technology cases is shown in Figure 8-1.

Figure 8-1



SECTION 9.0

Equivalent BACT Analysis

Basin Electric does not consider the Best Available Control Technology (BACT) requirement as a process that should be used to define or re-define a proposed emission source. Rather, the BACT process should be used to identify the emission control technologies available to reduce emissions from the source as defined by the proponent. The BACT process, coupled with PSD increment and ambient air quality modeling, will ensure that emissions from the proposed facility will be minimized and the proposed facility will not cause or contribute to any violation of an ambient air quality standard.

Notwithstanding Basin's objection to using the BACT process to define the proposed emission source, an equivalent "Top-Down" BACT Analysis was performed based on the three competing electricity generating technologies. Basin Electric will follow, to the extent possible, the 5-step top-down BACT evaluation process described in the NSR manual to evaluate the environmental, energy and economic impacts associated with PC, CFB and IGCC generating technologies. The BACT analyses for sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM), carbon monoxide (CO), and volatile organic compounds (VOC) air pollutants will be based on BACT air pollution control equipment utilized for each type of combustion technology.

9.1 Pollution Controls

The proposed new unit will be equipped with controls to limit the emissions of SO_2, NO_x, PM, CO, and VOC.

9.1.1 Sulfur Dioxide and Related Compounds

Emissions of sulfur dioxide and other sulfur compounds will be controlled on the new unit with the use of pulverized-coal (PC) boiler and a circulating dry scrubber (CDS) flue gas desulfurization (FGD) system. The FGD system will have a design SO_2 emission rate of 0.10 lb/MMBtu, which corresponds to an SO_2 removal efficiency of 91.3 percent at the design maximum coal sulfur content of 0.47 wt. percent.

In a CDS FGD system, water is injected into the flue gas prior to the inlet venturi of the absorber vessel to reduce the flue gas temperature to approximately 35°F above the adiabatic approach to the saturation point. Pebble sized lime (calcium oxide) reagent is hydrated with water to form hydrated lime (calcium hydroxide) powder. The hydrated lime is mixed with recycle solids captured in the downstream fabric filter and injected into the absorber vessel to remove SO2.

The solids are recycled between the CDS absorber and fabric filter to provide a long residence time for reagent particles to react with SO2 in the flue gas. The solids bleed stream consists of a dry calcium sulfite, calcium sulfate and fly ash byproduct. The collected dry solids will be conveyed pneumatically to a storage silo and trucked to a landfill disposal site or potentially reused.

9.1.2 Nitrogen Oxides

NO_x is formed in the PC boiler in the combustion process, particularly when the peak combustion temperatures in the flame exceed 2,500° F. The emissions of NO_x from the new unit will be limited through the use of Low NO_x Burners (LNB) with Overfire Air (OFA) and Selective Catalytic Reduction (SCR). LNB with OFA control the formation of NO_x by staging the combustion of the coal to keep the peak flame temperature below the threshold for NO_x formation. The burner initially introduces the coal into the boiler with less air than is needed for complete combustion. The flame is then directed toward an area where additional combustion air is introduced from over-fire air ports allowing final combustion of the fuel.

A selective catalytic reduction unit will also be installed on The new unit to further reduce the NO_x emissions. The proposed SCR is designed for high dust loading applications and will be located external from the boiler. The SCR system uses a catalyst and a reductant (ammonia gas, NH_3) to dissociate NO_x into nitrogen gas and water vapor. The catalytic process reactions for this NO_x removal are as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O, \text{ and}$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O.$$

The optimum temperature window for this catalytic reaction is between approximately 575 and 750 °F. Therefore, the SCR reaction chamber will be located between the boiler economizer outlet and air heater flue-gas inlet. The system will be designed to use ammonia as the reducing agent. The anhydrous ammonia will be transported to and stored onsite. Gaseous ammonia will be released from the aqueous ammonia and injected into Unit 3 through injection pipes, nozzles, and a mixing grid that will be located upstream of the SCR reaction chamber. A diluted mixture of ammonia gas in air will be dispersed through injection nozzles into the flue-gas stream. The ammonia/flue-gas mixture then enters the reactor where the catalytic reaction occurs.

The SCR system will be designed to achieve a controlled NO_x emission rate of 0.07 lb/MMBtu (30-day average).

9.1.3 Particulate Matter and PM_{10}

PM and PM_{10} will be controlled at the new unit by a fabric filter. The fabric filters operates by passing the particle-laden flue gas through a series of fabric bags. The bags accumulate a filter cake that removes the particles from the flue gas, and the cleaned flue gas passes out of the fabric filter. The fabric filters will have a particulate removal efficiency of greater than 99 percent.

The fabric filter system will consist of a number of parallel banks of filter compartments located downstream of the air preheaters and the flue gas desulfurization system and upstream of the induced draft fans. Individual filter compartments consist of a bottom collection hopper, a collector housing, and an upper plenum. A group of cylindrical filter bags, each covering a cylindrical wire cage retainer, hang from a tubesheet, which separates the upper plenum from the collector housing.

Particle-laden flue gas from the boiler enters the collector housing, just above the bottom collection hopper. The flue gas stream travels up through the collector housing where particles collect on the outside of the cylindrical filter bags. The filtered flue gas then travels up through the inside of the cylindrical filter bags, through the tubesheet, and out through the upper plenum. Particulate matter captured on the filter bags will form a filter cake. The filter cake increases both the filtration efficiency of the cloth and its resistance to gas flow.

Fabric filtration is a constant-emission device. Pressure drop across the filters, inlet particulate loading, or changes in gas volumes may change the rate of filter cake buildup, but will not change the final emission rate. Actual performance of a fabric filter depends on specific items, such as air/cloth ratio, permeability of the filter cake, the loading and nature of the particulate (e.g., irregular-shaped or spherical), and particle size distribution.

The filter bags must be cleaned routinely to remove accumulated filter cake. The cleaning frequency of the individual compartments will depend, in part, on the inlet grain loading and the flow resistance of the filter cake formed. It is anticipated that the fabric filter system will be designed as a pulse jet-type system. In a pulse jet-type system, gas flow through an isolated compartment is stopped and pulses of compressed air are blown down into the inside of each bag causing the filter bag to puff and fracturing the filter cake. The filter cake falls into the collection hopper for transport to the flyash-handling system.

Fabric filter system design involves inlet loading rates, flyash characteristics, the selection of the cleaning mechanism, and selection of a suitable filter fabric and finish.

9.1.4 Carbon Monoxide and Volatile Organic Compounds

CO and non-methane VOCs are formed from the incomplete combustion of the coal in the boiler. The formation of CO and VOCs is limited by controlling the combustion of the fuel and providing adequate oxygen for complete combustion. Thus, good combustion control is the technique to be used to limit CO and VOC emissions.

9.2 Combustion Technologies

9.2.1 Pulverized Coal Technology

Pulverized coal (PC) plants represent the most mature of coal-based power generation technologies considered in this assessment. Modern PC plants generally range in size from 80 MW to 1,300 MW and can use coal from various sources. Units operate at close to atmospheric pressure, simplifying the passage of materials through the plant, reducing vessel construction cost, and allowing onsite fabrication of boilers.

The concept of burning coal that has been pulverized into a fine powder stems from the fact that if the coal is made fine enough, it will burn almost as easily and efficiently as a gas. Crushed coal from the silos is fed into the pulverizers along with air preheated to about 580°F. The hot air dries the fine coal powder and conveys it to the burners in the boiler. The burners mix the powdered coal in the air suspension with additional pre-heated combustion air and force it out of nozzles similar in action to fuel being atomized by fuel injectors.

Combustion takes place at temperatures from 2400-3100°F, depending largely on coal rank. Steam is generated, driving a steam turbine-generator. Particle residence time in the boiler is typically 2-5 seconds, and the particles must be small enough for complete burnout to have taken place during this time. Steam generated in the boiler is conveyed to the steam turbine generator, which converts the steam thermal energy into mechanical energy. The turbine then drives the generator to produce electricity.

Most PC boilers operate with what is called a dry bottom. Combustion temperatures with subbituminous coal are held at 2400-2900°F. Most of the ash passes out with the flue gases as fine solid particles to be collected in a Fabric Filter (baghouse) before the stack.

The boiler produces combustion gases, which must be treated before exiting the exhaust stack to remove fly ash, NO_x, and SO_2. The pollution control equipment includes a fabric filter for particulate control (fly ash), LNB with OFA and SCR for removal of NO_x, and a circulating dry FGD system for removal of SO_2.

9.3 Circulating Fluidized Bed Technology

In a circulating fluidized bed (CFB) boiler, the coal is burned in a bed of hot combustible particles suspended by an upward flow of combustion air. The CFB fuel delivery system is similar to that of a PC unit, but somewhat simplified to produce a coarser material. The plant fuel handling system unloads the fuel, stacks out the fuel, crushes or otherwise prepares the fuel for combustion, and reclaims the fuel as required. The fuel is usually fed to the CFB by gravimetric feeders. The CFB units use a refractory-lined combustor bottom section with fluidized nozzles on the floor above the wind box, an upper combustor section, and a convective boiler section.

The bed material is composed of fuel, ash, sand, and the sulfur removal reagent (typically limestone), also referred to as sorbent. In the CFB the fuel is combusted to produce steam. Steam is conveyed to the steam turbine generator, which converts the steam thermal energy into mechanical energy. The turbine then drives the generator to produce electricity.

CFB combustion temperatures of 1,500 to 1,600°F are significantly lower than a conventional PC boiler of up to 3,000°F which results in lower NO_x emissions and reduction of slagging and fouling concerns characteristic of PC units. In contrast to a PC plant, sulfur dioxide can be partially removed during the combustion process by adding limestone to the fluidized bed.

CFBs are designed for the particular coal to be used. The method is principally of value for low grade, high ash coals which are difficult to pulverize, and which may have variable combustion characteristics. It is also suitable for co-firing coal with low grade fuels, including some waste materials. The advantage of fuel flexibility often mentioned in connection with CFB units can be misleading; the combustion portion of the process is inherently more flexible than PC, but material handling systems must be designed to handle larger quantities associated with lower quality fuels. Once the unit is built, it will operate most efficiently with whatever design fuel is specified.

The design must take into account ash quantities, and ash properties. While combustion temperatures are low enough to allow much of the mineral matter to retain its original properties, particle surface temperatures can be as much as 350°F above the nominal bed temperature. If any softening takes place on the surface of either the mineral matter or the sorbent, then there is a risk of agglomeration or of fouling.

The CFB produces combustion gases, which must be treated before exiting the exhaust stack to remove fly ash and sulfur dioxides. NO_x emissions can be mitigated through use of selective non-catalytic reduction (SNCR) using ammonia injection, usually in the upper area of the combustor. The pollution control equipment external to the CFB includes a fabric filter (baghouse) for particulate control (fly ash). A polishing FGD system may be required for additional removal of sulfur dioxides to achieve similar emission levels to PC units with FGD systems. Limestone is required as sorbent for the fluidized bed. A limestone storage and handling system is a required design consideration for CFB units.

CFB units have been built and operated up to 300 MW in size. Therefore, the NE Wyoming project would require one new boiler larger than previously demonstrated CFB boilers, or two 50 percent size CFB boilers to achieve 350 MW net output.

9.4 Integrated Gasification Combined Cycle (IGCC) Technology

Integrated gasification combined cycle (IGCC) is a developing technology that has potential application for electric generation in the United States. When fully developed, it may allow electricity production from coal at greater efficiencies and lower environmental impacts than traditional coal-fired power plants, and with the potential to co-produce other products, such as hydrogen for fueling of vehicles, carbon dioxide for tertiary oil production or chemicals production, and sulfuric acid or elemental sulfur. Continued research of IGCC should be a top priority of the United States, with specific research areas including the reliability and availability of the integrated gasification/generation systems, improvements to emission controls including mercury removal, and efficiency improvements, such as hot gas cleaning techniques.

IGCC systems combine elements common to chemical plants and power plants. Because chemical process engineering training and experience are required to develop and operate an IGCC plant, it requires expertise typically not found in utility companies. Major components of a typical IGCC plant include coal handling and processing, cryogenic oxygen plant(s), pressurized gasification systems, "syngas" quench and cooling systems, syngas scrubbers with carbonyl sulfide hydrolysis systems and equipment to flash or otherwise separate H_2S off the scrubbing liquid, either a sulfuric acid plant or a Claus sulfur plant, combustion turbines, heat recovery steam generators (HRSG), and steam turbine(s).

At least five types of gasification technologies currently exist.[2] These include dry-ash moving bed, slagging moving bed, dry ash fluidized bed, agglomerating fluidized bed, and slagging entrained-flow gasifiers. Oxygen for the partial oxidation of the coal can be supplied through either oxygen from an air separation unit (cryogenic oxygen plant) or through compressed air. The compressed air for either the oxygen plant or for direct feed to the gasifiers can be supplied either through dedicated air compressors or by bleeding a portion of the air from the compression section of the gas turbine. Many choices of gas cleanup systems are available. Fuel utilization efficiency improvements can be achieved by feeding steam produced by cooling the raw syngas into the HRSG or steam turbine, although this complicates the startup, shutdown, and operation of the facility and creates major challenges

[2] "Major Environmental Aspects of Gasification-Based Power Generation Technologies - Final Report", Unites States Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory, December 2002.

in the ability of the facility to adjust total electrical output to follow demand load. There are no clear "best" choices among these many technology selections.

At this time, IGCC technology is not fully developed, and it is not technically feasible in the context of a BACT analysis. According to George Rudins, United States Department of Energy (DOE) deputy assistant secretary for coal, "Right now, there is not a single company producing a turnkey IGCC power plant, so you have components sold by different companies, and that increases the challenge."[3] Therefore, at this time, the burden is on the owner and engineer of the facility to integrate the gasification, oxygen, gas cleaning, and gas combustion systems, which substantially increases the complexity and risk of IGCC plant development. Representatives of DOE, the utility industry, and environmental groups generally agree that tax credits or other economic incentives will be required to offset the technological and financial risks associated with development of commercial IGCC plants.

Because the burden for technological development rests on the project developer, the technology cannot truly be considered commercially available. The EPA states that, "A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales state of development. "[4] While various types of gasifiers, gas cleaning unit processes, and combustion turbines are commercially available, there are no vendors offering commercial sales of complete IGCC package systems. Furthermore, EPA states that, "Vendor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique and could contribute to a determination of technical feasibility or technical infeasibility."[5] Basin Electric is not aware of any vendors offering guarantees on the air emissions from either the combustion turbine or tail gas incinerator components of an IGCC system consuming sub-bituminous coal; this problem is a function of the fact that developers must integrate systems offered by different vendors.

Basin Electric is aware that General Electric (GE) has recently purchased Chevron/Texaco's IGCC technology, and is in the process of developing a standard plant design for an IGCC system with Bechtel. This has not yet been accomplished, and the level of uncertainty regarding specifics of the plant design remains high. Firm pricing for such a system is not yet available.

A case in point regarding the technological and commercial terms challenges is the recent Pinon Pine project in Storey County, Nevada. Innovative concepts incorporated in the design of this plant included use of Kellogg KRW air-blown gasifiers as an alternative to oxygen-blown gasifiers, and use of hot gas cleanup technology. The project was funded 50 percent by the DOE, and benefited from the technological expertise of the DOE. Despite the expertise available to the project, the plant never achieved steady state operation, and as such, environmental and economic performance of the project could not be evaluated. Eighteen unsuccessful attempts were made to start up the gasification system; each subsequent startup attempt was not begun until the cause of the previous malfunction was

[3] "Coal - Can it ever be clean", *Chemical & Engineering News*, February 23, 2004.

[4] EPA, *New Source Review Workshop Manual*, October 1990, Page B.18.

[5] *New Source Review Workshop Manual*, Page B.20.

resolved.[6] Technical problems with the system included failure of HRSG components, unacceptable temperature ramps in the gasifiers, which caused failures in gasifier refractory, a fire in the particulate removal system, and multiple other problems with the particulate removal system. While many lessons were learned from development of the plant, and these lessons may lead to improved plant design in the future, the plant certainly could not be considered a technological success.

Only two commercial IGCC plants are currently in operation in the United States. These are the Wabash River project in central Indiana and Tampa Electric Company's Polk Power Project in Florida. Both projects were co-funded by the DOE as demonstration projects. As these projects involved development of technology, substantial modifications were made to both projects after initial construction. There has never been a commercial IGCC plant in the United States that was not either co-funded by DOE or otherwise provided financial incentives for the purpose of technology demonstration.

Furthermore, little operating experience exists regarding IGCC plants consuming sub-bituminous coal. None of the four commercial-scale IGCC plants currently operating in the world consume sub-bituminous coal; all four consume either bituminous coal or petroleum coke.[7] One commercial-scale IGCC plant, the Dow Chemical/Destec LGTI project, was previously operated on sub-bituminous coal; however this project was supported with guaranteed product price support offered by Dow Chemical and the U.S. Synthetic Fuels Corporation, and was promptly shut down when the price support expired.[8] National Energy Technology Laboratory (NETL) also notes that, "The following developments will be key to the long term commercialization of gasification technologies and integration of this environmentally superior solid fuels technology into the existing mix of power plants…[fifth of eight bullets] Additional optimization work for the lower rank, sub-bituminous and lignite coals."[9] It is clear that the majority of operating experience for coal-based IGCC plants is with bituminous coals and that further study is required to prove the technical and economic feasibility of IGCC operation with sub-bituminous coals, and in the context of published cost data, it would be irresponsible to assume that an IGCC plant consuming sub-bituminous coal could match the performance of an IGCC plant consuming bituminous coal.

A February 2004 paper by members of the John F. Kennedy School of Government at Harvard University proposes innovative financing mechanisms for IGCC projects. This proposal is driven in part by the fact that, due to the increased risks presented by IGCC projects, the cost of capital hinders IGCC plant development. The study notes that, "The overnight capital cost of IGCC is currently 20 to 25 percent higher than [pulverized coal] systems and commercial reliability has not been proven." [10] The paper further acknowledges that due to risk, private investors are unlikely to develop IGCC projects and state public utility commissions (PUCs) are unlikely or unable to shift the burden for these costs to the

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6 Project Fact Sheet - Pinon Pine IGCC Power Project, United States Department of Energy - Office of Fossil Energy, http://www.netl.doe.gov/cctc/factsheets/pinon/pinondemo.html, July 2004.

7 "Major Environmental Aspects…", Page 1-25.

8 "Major Environmental Aspects…", Page 1-19.

9 "Gasification Plant Cost and Performance Optimization", U.S. Department of Energy National Energy Technology Laboratory, Revised August 2003, Page ES-3.

10 Rosenberg, William G., Dwight C. Alpern, and Michael R. Walker, "Financing IGCC – 3Party Covenant," BSCIA Working Paper 2004-01, Energy Technology Innovation Project, Belfer Center for Science and International Affairs, Page 1.

ratepayer. Therefore, a "3 Party Covenant" between the federal government, state PUCs, and equity investors is proposed to ensure a revenue stream for an IGCC project (i.e., to ensure that facility offtake can be sold even if it is not the lowest cost generation resource) and to develop financing at lower interest costs than for typical generation projects, thus mitigating business risk and higher cost of capital. If such innovative measures are required to spur successful development of IGCC projects, for a utility that is required by law to develop new projects to meet customer demand yet satisfy PUC requirements for financial responsibility, it seems imprudent to consider "forcing" the utility to select IGCC via the BACT process.

In fact, the Public Service Commission of Wisconsin (PSCW) recently came to a very similar conclusion. Wisconsin Energy Corporation (WE Energy) proposed construction of two new PC generating units and one IGCC unit at its Elm Road project south of Milwaukee. PSCW reviewed the project within the context of its statutory mandate to consider concerns regarding engineering, economics, safety, reliability, environmental impacts, interference with local land use plans, and impact on wholesale competition. PSCW concluded that the IGCC project was not an acceptable risk or financial burden for its ratepayers and denied WE Energy's request to develop it.

In its November 10, 2003, decision, the PSCW made the following finding:

> "5. The two SCPC [supercritical pulverized coal] units are reasonable and in the public interest after considering alternative sources of supply, individual hardships, engineering, economic, safety, reliability, and environmental factors. The IGCC unit does not meet this standard."

The proposed new unit is a PC unit similar to those approved by the PSCW.

None of the commercial systems constructed to date have operated at the almost 5,000-foot altitude of the proposed new unit. This altitude will result in de-rating of the combustion turbines, and would thus require a larger combined cycle component of the IGCC system to produce the same output as a system constructed at lower elevation. This would further degrade IGCC economics at the NE Wyoming Project.

The longer time required for startup/shutdown, and inflexibility of system output for load-following, of an IGCC system versus a PC system creates additional challenges for utilities. Startups have reportedly required up to 70 hours, and flaring of treated and untreated syngas during these startups can create substantial additional air emissions, which are not typically included in IGCC emission estimates.

IGCC systems also have relatively low availability, due in large part to frequent maintenance required for gasifier refractory repair. This creates the need for redundant gasifier systems, or burning pipeline natural gas as a backup fuel which further increases the system capital and operating costs and operating complexity.

IGCC is thus a generation method, which is fundamentally different from that of the proposed project in terms of technology, costs, and business risk. BACT has not historically been used as a means of redefining the emission source. EPA regulations and policy guidance make it clear that BACT determinations are intended to consider alternative emission control technologies, not to redefine the entire source.

9.5 BACT Determination

This section presents the BACT analysis.

9.5.1 Applicability

The requirement to conduct a BACT analysis and determination is set forth in section 164(a)(4) of the Clean Air Act and in federal regulations 40 CFR 52.21(j).

9.5.2 Top-Down BACT Process

EPA has developed a process for conducting BACT analyses. This method is referred to as the "top-down" method. The steps to conducting a "top-down" analysis are listed in EPA's "New Source Review Workshop Manual," Draft, October 1990. The steps are the following:

- Step 1 – Identify All Control Technologies
- Step 2 – Eliminate Technically Infeasible Options
- Step 3 – Rank Remaining Control Technologies by Control Effectiveness
- Step 4 – Evaluate Most Effective Controls and Document Results
- Step 5 – Select BACT

Each of these steps has been conducted for the SO_2, NO_x, PM, CO and VOC pollutants and is described below.

9.5.3 SO_2, NO_x, PM_{10}, CO and VOC Analysis

The BACT analysis for Sulfur Dioxide, Nitrogen Oxides, Particulate Matter, Carbon Monoxide and Volatile Organic Compounds is presented below.

9.5.3.1 Step 1 – Identify All Control (Combustion) Technologies

The first step is to identify all available combustion technologies. Most recent PSD permit applications submitted to the applicable permitting agencies proposing to construct a coal combustion steam electric generating unit have defined the source as a pulverized coal-fired (PC) unit. In a majority of the PSD permit reviews, the permitting agency applied the top-down BACT for emission controls based on the source as defined by the applicant (i.e. PC unit). State permitting agencies in Wisconsin, West Virginia and Wyoming have not required CFB and/or IGCC technologies to be considered in recent BACT determinations.

Combustion technology information related to this type of BACT Analysis is not available from the EPA RACT/BACT/LAER Clearinghouse (RBLC) database accessible on the Internet. However, recent similar BACT determinations have evaluated the following potential combustion technology emission reduction options:

- Pulverized Coal (PC);
- Circulating Fluidized Bed (CFB);
- Integrated Gasification Combined Cycle (IGCC).

9.5.3.2 Step 2 – Eliminate Technically Infeasible Options

9.5.3.2.1 PC Option

The PC with FGD option is technically feasible for use in reducing emissions from The new unit. Most of the PRB coal used for electricity generation is burned in PC plants. PC units experienced many problems during the initial use of PRB coals, but experience has resulted in development of PC boiler designs to successfully burn PRB coals. PC designs for PRB coal are based on the specific characteristics of the fuel such as moisture content, ash composition and softening temperature, and sulfur content.

9.5.3.2.2 CFB Option

The majority of existing utility CFB units burn bituminous coal, anthracite coal waste or lignite coal. The operating history of utility CFB boilers burning PRB or other types of subbituminous coal is limited. CFB technology typically has an economic advantage only when used with high ash and/or high sulfur fuels. Therefore, high sulfur bituminous, high sulfur petroleum coke, high ash coal waste, high ash lignite and other high ash biomass fuels are the typical applications for CFB technology.

PRB coals may have a tendency to produce small particle size (fine) fly ash that makes it more difficult to maintain the required bed volume in a CFB unit. Therefore, additional quantities of inerts such as sand and limestone may be required for a CFB unit burning low sulfur/low ash PRB coals.

A joint Colorado Springs Utilities / Foster Wheeler 150 MW Advanced CFB demonstration project at the Ray D. Nixon Power Plant south of Colorado Springs was proposed and accepted by DOE NETL in 2002 as part of the federal Clean Coal Power Initiative (CCPI). DOE agreed to a $30 million cost share of the $301.5 million project. The next generation CFB unit would be designed to burn PRB coal and PRB blended with coal waste, biomass and petroleum coke. However, Colorado Springs Utilities and Foster Wheeler cancelled and withdrew from the CCPI project in 2003.

The CFB option is probably technically feasible for use in reducing SO_2 emissions from the new unit, but it is not considered the best application for PRB coal.

9.5.3.2.3 IGCC Option

The only commercial size IGCC demonstration plant that has operated with PRB coal fuel was the Dow Chemical Louisiana Gasification Technology, Inc. (LGTI) plant in Plaquemine, LA. This plant used an oxygen blown E-Gas entrained flow gasifier and is reported to have operated successfully from 1987 to 1995. The plant is now shutdown.

The Power Systems Development Facility (PSDF), located near Wilsonville, Alabama, is a large advanced coal-fired power system pilot plant[11]. It is a joint project of DOE NETL, Southern Company and other industrial participants. The Haliburton KBR Transport Reactor was modified from a combuster to coal gasifier operation in 1999. The initial gasification tests have concentrated on PRB coals because their high reactivity and volatiles were found to enhance gasification. The highest syngas heating values were achieved with PRB coal, since PRB coal is more reactive than bituminous coals.

[11] Ref. 10.

Southern Company, Orlando Utilities Commission, and Kellogg Brown and Root, recently submitted a proposal to DOE NETL for the Round 2 Clean Coal Power Initiative (CCPI) solicitation[12]. They propose to construct and demonstrate operation of a 285 MW coal-based transport gasifier plant in Orange County, Florida. The proposed facility would gasify sub-bituminous coal in an air-blown integrated gasification combined cycle power plant based on the KBR Transport Gasifier. Southern Company estimated the total cost for the project at $557 million ($1954/MW) and has requested $235 million of DOE funds to support the project.

The IGCC option is probably technically feasible for use in reducing SO_2, NO_x, PM, CO and VOC emissions from the new unit, but it is not considered the best application for PRB coal.

9.5.3.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Emission rates for each of the combustion technologies are provided in Table 9-1.

TABLE 9-1
Comparison of Coal Combustion Technology Potential BACT Emission Rates
Basin Electric Dry Fork Station Technology Evaluation

	Emission Rates for Coal Combustion Technologies (Lb/MMBtu)		
Pollutant	**PC (Potential BACT)**	**CFB (Potential BACT)**	**IGCC (Potential BACT)**
SO_2	0.10	0.10	0.03
NO_x	0.07	0.09	0.07
PM_{10}	0.019	0.019	0.011
CO	0.15	0.15	0.03
VOC	0.0037	0.0037	0.004

9.5.3.4 Step 4 – Evaluate Most Effective Controls and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology.

Most of the PRB coal used for electricity generation is burned in pulverized coal (PC) plants. PC units experienced many problems during the initial use of PRB coals, but experience has resulted in development of PC boiler designs to successfully burn PRB coals. PC designs for PRB coal are based on the specific characteristics of the fuel such as moisture content, ash composition and softening temperature, and sulfur content.

CFB technology is an alternative combustion technique that could be considered for this power plant application. However, the proposed new unit emission rates are consistent with emission rates achievable with CFB boilers.

[12] Ref. 11.

IGCC is a promising technology, which presents the opportunity for electric generation at lower emissions of criteria air pollutants than conventional coal technology. However, at this time, significant technical uncertainty exists; at least one recent project ended in failure. No vendors offer complete IGCC packages, and as a result project owners must integrate the many components of the IGCC system and must develop projects with no emission guarantees from vendors. At the current time, in order for IGCC projects to satisfy the financial and risk criteria required to obtain PUC approval to pass projects costs onto ratepayers, tax credits, innovative financing, or other financial incentives are required.

An incremental cost analysis has been prepared for PC versus CFB technology and PC versus IGCC technology. A summary of the results is shown in Table 9-2. The detailed cost analysis is provided in Appendix E. The incremental cost difference between PC and CFB is $987 per additional ton of pollutant removed. CFB technology removes less overall tons of pollutants while having a slightly lower total annualized cost. The incremental cost difference between PC and IGCC is $24,767 per additional ton of pollutant removed. Basin Electric believes that the high additional cost of IGCC combustion technology is not warranted for this project based on the use of low sulfur coal and the limited additional tons of pollutants removed.

TABLE 9-2
Comparison of Coal Combustion Technology Economics
Basin Electric Dry Fork Station Technology Evaluation

	Costs ($)		
Factor	**PC**	**CFB**	**IGCC**
Total Installed Capital Costs	$ 482,000,000	$ 497,000,000	$ 720,000,000
Total Fixed & Variable O&M Costs	$ 23,900,000	$ 22,600,000	$ 49,300,000
Total Annualized Cost	$ 55,600,000	$ 55,300,000	$ 109,200,000
Incremental Annualized Cost Difference: PC versus CFB, and PC versus IGCC	-	$ (300,000)	$ 53,700,000
Incremental Tons Pollutants Removed: PC versus CFB, and PC versus IGCC	-	(324)	2,166
Incremental Cost Effectiveness per Ton of Additional Pollutant Removed: PC versus CFB, and PC versus IGCC	-	987	24,767

9.5.3.5 Step 5 – Select BACT

The final step in the top-down BACT analysis process is to select BACT. Based on a review of the technical feasibility, potential controlled emission rates and economic impacts of PC, CFB and IGCC combustion technologies, the PC-based plant design represents BACT for the proposed new unit.

SECTION 10.0

Impact of Plant Size Increase

In December 2004, Basin Electric Power Cooperative (BEPC) announced plans to build a 250 MW (net) coal-based generation resource in Northeast Wyoming. In May 2005, based on a revised load forecast for Basin Electric's member cooperatives, the net plant output for the new coal unit was increased to 350 MW net. The technology comparison at this rating is virtually identical to the 250 MW design case.

Impact on Plant Design and Heat Rate

A 250 MW net IGCC plant would most likely use two 7EA gas turbines and a small amount of duct firing of syngas in the HRSGs to generate the required export power to the grid based on the PRB coal fuel and the plant elevation of 4,250 feet. The gasifier would be sized to supply syngas to the Auxiliary Boiler for drying the high moisture PRB coal, syngas to the gas turbines, and syngas for duct-firing in the HRSGs.

A 350 MW net IGCC plant would most likely use two 7FA gas turbines and a larger amount of duct firing of syngas in the HRSGs to generate the required export power to the grid. The larger 7FA gas turbines used in the 350 MW plant are higher efficiency compared to the smaller 7EA gas turbines, however, this will probably be offset by the larger amount of syngas used for duct-firing in the larger power plant. Duct-firing lowers the overall plant efficiency of a gas turbine combined cycle power plant. Therefore, it is expected that the net plant heat rate will be comparable for the 250 MW and 350 MW plant sizes.

Impact on Cost

The larger 350 MW IGCC plant is expected to have some cost savings on a $/kW installed capital cost basis due to economy of scale. However, this economy of scale cost savings will be matched by the similar economy of scale cost savings achieved by a PC or CFB unit when going from a 250 to 350 MW plant size.

SECTION 11.0

Conclusions and Recommendations

11.1 Baseload Capacity

PC and CFB technologies are capable of achieving an 85 percent annual capacity factor, and are suitable for baseload capacity. The IGCC technology is only capable of achieving an 85 percent annual capacity factor for a baseload unit by adding redundant back-up systems or using natural gas as a backup fuel for the combustion turbine combined cycle part of the plant.

11.2 Commercially Available and Proven Technology

PC and APC technology is commercially available and proven for PRB coal. The CFB technology has been commercially demonstrated for bituminous, low sodium lignite and anthracite waste coals, however, long term commercial operation with PRB coal has not been demonstrated.

IGCC technology is still under development. All four commercial demonstration units that are operating in the U.S. and Europe were subsidized with government funding. Six of the thirteen second round Clean Coal Power Initiative (CCPI) proposals that were received and announced by DOE NETL in July 2004, were for demonstration IGCC plants to receive government cost sharing[13]. The goal of the DOE CCPI program is to assist industry with development of new clean coal power technologies. It is anticipated that IGCC will not be developed for full commercial use before the 2015 time period.

11.3 High Reliability

Both PC and CFB technologies have demonstrated high reliability. IGCC technology has demonstrated very low reliability in the early years of plant operation. Improved reliability has been recently demonstrated after design and operation changes were made to the facilities, however, the availability of IGCC units is still much lower than PC and CFB units.

11.4 Cost Effective

PC technology is the most cost effective for a new 250 MW PRB coal power plant in Northeast Wyoming. A PC unit will have the lowest capital and operating & maintenance cost of all three technologies evaluated. The CFB technology would have a slightly higher capital cost, but lower operating and maintenance cost compared to a PC unit. The IGCC technology would have a much higher capital, operating and maintenance cost compared to ~~both the PC and CFB technologies.~~

[13] Ref. 11.

11.5 Summary

PC technology is capable of fulfilling Basin Electric's need for new generation, and is recommended for the Basin Electric Dry Fork Station Project. CFB technology meets Basin Electric's need, however, it lacks demonstrated long-term operating experience on PRB coal and in the final analysis would be more costly.

IGCC technology is also judged not capable of fulfilling the need for new generation. IGCC does not meet the requirement for a high level of reliability and long-term, cost-effective, and competitive generation of power. In addition to higher capital costs, there are problem areas, discussed previously, that have not demonstrated acceptable availability and reliability. The current approaches to improving reliability in these areas result in less efficient facilities, negatively impacting the cost-effectiveness. DOE has a Clean Coal Technology program with the goal of providing clean coal power-generation alternatives which includes improving the cost-competitiveness of IGCC. However, the current DOE time frame (by 2015) does not support Basin Electric's 2011 needs.

GCC offers the potential for a more cost effective means of CO_2 removal as compared to PC and CFB technologies should such removal become a requirement in the future. However, at this time, it is only speculative as to if such requirements will be enacted, when they will be enacted, and what they will consist of and apply to if enacted. The risk of installing a more costly technology, that has not been proven to be reliable and for which strong commercial performance guarantees are not available, is far too great for Basin Electric to take on for such speculative purposes.

11.6 Continuing Activities

Planned conference attendance

Basin Electric plans to attend the 2005 Gasification Technologies Council annual conference in October, 2005, in San Francisco, CA.

Canadian Clean Power Coalition

Basin Electric has been working closely with other lignite and sub-bituminous users in the Canadian Clean Power Coalition (CCPC) on IGCC technology and advanced "conventional" technologies such as oxy fuel firing and advanced amine scrubbing systems for low rank coals. The CCPC has funded feasibility studies from ConocoPhillips/Fluor, Shell and Future Energy. Basin Electric will monitor and review the results of these studies.

Wilsonville PDSF

Basin Electric has been supporting the EPRI / Southern Company PDSF testing in Wilsonville, Alabama. Basin Electric will monitor and review the results of this testing.

Future investigations

Basin Electric and their engineering consultants continue to review the ongoing performance of the four IGCC demonstration plants and monitor the status of commercial IGCC offerings.

SECTION 12.0

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Appendix A Coal Plant Technology Performance and Emissions Matrix

Plant Inputs

CLIENT: Basin Electric
PROJECT: Dry Fork Station Project
Date: 10/13/2005 16:39
Revision: P

INPUTS

Case No.		PC	CFB	Conventional IGCC	Ultra-Low Emission IGCC
Description	Units	Pulverized Coal w/HD SCR and CDS	Circulating Fluid Bed w/SNCR and CDS	IGCC w/Syngas MDEA	IGCC w/Syngas Selexol, Cat-Ox and SCR
General Plant Technical Inputs					
Number of Units	Integer	1	1	1	1
Boiler Technology	PC or CFB	PC	CFB	IGCC	IGCC
Gross Plant Output	kW	303,333	303,333	321,176	321,176
Gross Plant Heat Rate	Btu/kW-Hr	9,450	9,720	8,925	8,925
Heat Input to Boiler	MMBtu/Hr	2,867	2,948	2,867	2,867
Auxiliary Power	%	10.00%	10.00%	15.00%	15.00%
Auxiliary Power	kW	30,333	30,333	48,176	48,176
Net Plant Output	kW	273,000	273,000	273,000	273,000
Net Plant Heat Rate w/o Margin	Btu/kW-Hr	10,500	10,800	10,500	10,500
Margin on Net Plant Heat Rate	%	0.00%	0.00%	0.00%	0.00%
Net Plant Heat Rate w/Margin	Btu/kW-Hr	10,500	10,800	10,500	10,500
Plant Capacity Factor	%	85%	85%	85%	85%
Percent Excess Air to Boiler (Design)	%	20%	20%	N/A*	N/A
Infiltration	%	5%	5%	N/A	N/A
Percent Excess Air in Boiler	%	125%	125%	N/A	N/A
Air Heater Leakage	%	10%	10%	N/A	N/A
Air Heater Outlet Gas Temperature	°F	294	294	N/A	N/A
Pressure After Air Heater	In. of H2O	-12	-12	N/A	N/A
Inlet Air Temperature	°F	100	100	100	100
Plant Site Elevation (For Ref. Only)	Ft. Above MSL	4,250	4,250	4,250	4,250
Ambient Absolute Pressure @ Plant Site	In. of Hg	25.1	25.1	25.1	25.1
Ambient Absolute Pressure @ Stack Exit	In. of Hg	24.7	24.7	24.7	24.7
Moisture in Air	lb/lb dry air	0.012	0.012	0.012	0.012
Select Coal (see Coal Library Sheet)	1 to 8	1	1	1	1
Coal Name		Dry Fork Comm Permit Values	Dry Fork Comm Permit Values	Dry Fork Comm Permit Values	Dry Fork Comm Permit Values
Ash Split:					
Fly Ash	%	80%	80%	5%	5%
Bottom Ash	%	20%	20%	95%	95%
Stack Height	Ft	500	500	N/A	N/A
Stack Exit Velocity	Ft/Sec	95.27	92.55	N/A	N/A

* N/A - Not Applicable

Emission Calcs

Emission Analysis	**Units**	**PC**	**CFB**	**Conventional IGCC**	**Ultra-Low Emission IGCC**
Net Plant Output	**MW**	**273**	**273**	**273**	**273**
Heat Input to Boiler	**MMBtu/Hr**	**2,867**	**2,948**	**2,867**	**2,867**
Plant Capacity Factor	**%**	**85%**	**85%**	**85%**	**85%**
NOx Emissions					
Annual NOx Emission Rate	Lb/MMBtu	0.070	0.090	0.070	0.035
	Lb/Hr	200.7	265.3	200.7	100.3
	Lb/net MW-Hr	0.735	0.972	0.735	0.368
	Tons/Year	747	988	747	374
SO2 Emissions					
Annual SO2 Emission Rate	Lb/MMBtu	0.100	0.100	0.030	0.015
	Lb/Hr	287	295	86	43
	Lb/net MW-Hr	1.05	1.08	0.32	0.16
	Tons/Year	1,067	1,098	264	132
CO Emissions					
30-Day CO Emission Rate	Lb/MMBtu	0.150	0.150	0.030	0.015
	Lb/Hr	430	442	86	43
	Lb/net MW-Hr	1.575	1.620	0.315	0.158
	Tons/Year	1,600.8	1,646.5	320.2	160.1
VOC Emissions					
VOC Emission Rate	Lb/MMBtu	0.0037	0.0037	0.0040	0.0020
	Lb/Hr	10.606	10.909	11.466	5.733
	Lb/net MW-Hr	0.039	0.040	0.042	0.021
	Tons/Year	39.5	40.6	42.7	21.3
PM Emissions					
PM Emission Rate	Lb/MMBtu	0.019	0.019	0.011	0.011
	Lb/Hr	54.5	56.0	31.5	31.5
	Lb/net MW-Hr	0.200	0.205	0.116	0.116
	Tons/Year	203	209	117	117
Total NOx, SO2, CO, VOC & PM Emissions					
Total NOx, SO2, CO, VOC & PM Emission Rate	Lb/MMBtu	0.3427	0.3627	0.1450	0.0780
	Lb/Hr	982.350	1,069.340	415.652	223.592
	Lb/net MW-Hr	3.598	3.917	1.523	0.819
	Tons/Year	3,657.3	3,981.2	1,491.0	804.2

Appendix B Semi-Dry FGD Evaluation

CIRCULATING DRY SCRUBBER
FEASIBILITY REVIEW
PROJECT NUMBER 11786-001

PREPARED FOR
BASIN ELECTRIC POWER COOPERATIVE

FINAL SEPTEMBER 2005

PREPARED BY

Sargent & Lundy LLC

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REPORT PREPARED, REVIEWED, AND APPROVED BY SARGENT & LUNDY LLC:

Prepared by:	William E. Siegfriedt Consultant	September 30, 2005 Date
Reviewed by:	William Rosenquist Technical Advisor	September 30, 2005 Date
Approved by:	William DePriest Project Director	September 30, 2005 Date

EXECUTIVE SUMMARY

Basin Electric's Dry Fork Station requires flue gas desulfurization (FGD) technology at the edge of the technical envelope. The combination of the low-sulfur Powder River Basin (PRB) coal and the ultra-low emission requirement (due to the proximity to Class I areas) demands unprecedented SO_2 removal performance, in terms of low sulfur inlet loading/high SO_2 removal efficiency. This report investigates the two available technologies that can achieve this performance and compares them with respect to capital cost, operating cost, technical considerations and commercial considerations. A summary of these findings is in the following table.

	Pros	Cons
Wet Limestone/ Forced Oxidation FGD	Lower O&M cost than the CDS	Higher water consumption
Circulating Dry Scrubber	Lower capital cost	Very weak suppliers Very weak data on stoichiometric ratio at high removal rates when inlet SO_2 is higher than 1.5 lb/MBtu

OBJECTIVES

Basin Electric's Dry Fork Station will be a mine-mouth power plant located next to the Dry Fork mine near Gillette, Wyoming. The Dry Fork coal deposit consists of a seam about 70 feet deep. The bulk of the seam has about an uncontrolled rate of 0.8 lb SO_2/MBtu ("Commercial" grade), but a blend using the upper 7 feet would have on average twice that much sulfur, with peaks even higher. The mine currently serves power plants by rail, shipping only the "commercial" grade low-sulfur coal and turning the higher-sulfur layer back into the ground.

The mine is located about 115 miles from Wind Cave National Park, in the Black Hills of South Dakota. Emission dispersion modeling shows that occasional impacts on visibility in the park would occur unless SO_2 emissions from the plant were kept extremely low. If the permit limit were established at 0.08 to 0.10 lb

SO_2/Mbtu, operation as low as 0.06 to 0.08 lb SO_2/MBtu would be prudent. The objective of this study is to determine the best flue gas desulfurization (FGD) process to achieve these low emissions using the Dry Fork coals.

Potential desulfurization technologies include:

- Wet lime/limestone, forced oxidation FGD
- Circulating Dry Scrubber (CDS)
- Spray Dryer FGD
- Fluidized Bed Combustion (FBC) Boiler

Spray dryer FGD is not able to achieve the 95% to 98% SO_2 removal efficiency necessary to achieve the emission requirements on the higher-sulfur coal, so it was eliminated from further consideration. If the project were to consider only the "commercial"-grade fuel, and the inlet SO_2 were maintained below 1.2 lb/MBtu, then the spray dryer FGD would be feasible.

Although the FBC boiler with a follow-on FGD system would be able to meet the SO_2 reduction requirements, it may not be able to achieve the necessary NO_X emission limits even with selective non-catalytic reduction (SNCR). To meet the requirements, SCR would be required, similar to a PC boiler. (For more discussion of this point, refer to CH2M Hill's report "Coal Power Plant Technology Evaluation for Dry Fork Station", dated September 2, 2005.) Based on inability to meet projected NOx requirements economically, the FBC boiler was also eliminated from further consideration in this study. This report focuses on comparing the wet FGD process with the CDS process.

1. PROCESS DESCRIPTIONS

1.1 WET LIME/LIMESTONE FORCED OXIDATION FGD DESCRIPTION

Wet lime/limestone forced oxidation flue gas desulfurization technology (wet FGD) is the conventional acid gas cleanup process. Over the past two decades, spray dryer FGD has become common for scrubbing low-sulfur gases, leaving wet FGD to the high-sulfur (uncontrolled SO_2 emission rates greater than 2 lb/MBtu) applications. However, the linking of reagent admission to moisture addition in the spray dryer limits the spray dryer scrubbing to 94% SO_2 removal. On the other hand, wet FGD is capable of effectively scrubbing low-sulfur gases up to 97.5% removal. Wet FGD typically uses limestone, which costs much less than lime. However, the limestone grinding system adds to the already high capital cost of wet FGD. In high-sulfur service, the cost of lime becomes prohibitive, so new lime-based wet FGD systems have become rare. Wet FGD is installed after the particulate removal system, and usually after all draft fans, putting it just before the stack. There are many variations in absorber concept and configuration, but the process chemistry is generally similar. Wet FGD is offered by the major boiler suppliers and several process suppliers.

Flue gas is treated in an absorber by passing the gas stream counter-currently through a slurry of fine-ground limestone that is arrayed to promote intimate gas contact with fine droplets or thin films. The SO_2 gas is sorbed into the liquid and the liquid moves on, to the integral reaction tank. Large quantities of air are injected into the tank, and it is agitated and recirculated into the absorption zone. Residence time of calcium-based solids in the tank is long enough to permit reaction of the sulfur-bearing ions stripped from the flue gas with the calcium ions and the oxygen in the air to produce high-quality gypsum. The reagent quality and the thoroughness of the by-product washing can be varied to make this gypsum either a highly acceptable landfill material or a highly-sought-after ingredient for commercial wallboard. If commercial wallboard is produced, a typical by-product is wastewater containing the inert matter and chlorine that was present in the coal. This water must be treated to remove these contaminants before discharge.

1.1.1 Process Chemistry

The SO_2 absorbed in the slurry reacts with lime in the slurry. About 70% converts to calcium sulfite ($CaSO_3$) in the following reaction:

$$SO_2 + CaO + 1/2\ H_2O \Rightarrow CaSO_3 \bullet 1/2\ H_2O$$

Most of the rest forms calcium sulfate ($CaSO_4$):

$$SO_2 + CaO + 2\ H_2O \Rightarrow CaSO_4 \bullet 2\ H_2O$$

Air blown into the reaction tank provides oxygen to convert most of the calcium sulfite ($CaSO_3$) to calcium sulfate ($CaSO_4$):

$$CaSO_3 + \frac{1}{2}O_2 + 2H_2O \Rightarrow CaSO_4 \bullet 2H_2O$$

This forced oxidation process generates the relatively pure gypsum (calcium sulfate) by-product.

1.1.2 Reagents and By-Products

If limestone is used, the stone is usually delivered as ¾" x 0" stone. Large, water-filled ball mills grind the stone to an ultrafine slurry of 25% to 30% solids for use in the scrubber. The reagent is fed to the absorber to replenish limestone consumed in the reaction, and the feed rate is typically controlled based on the removal efficiency required.

The by-product is fully oxidized to $CaSO_4$ with traces of $CaSO_3$, calcium hydroxide, calcium carbonate and ash, particularly if the objective is to produce landfill material. For wallboard-grade gypsum, non-gypsum impurities will be kept to a minimum. Wallboard is a low-value material with high shipping cost due to its weight. The remoteness of the plant site from major urban centers that would be markets for wallboard mean it is unlikely that gypsum can be sold from this plant at an FOB price better than the cost of disposal.

1.1.3 Commercial Status

Wet FGD is the conventional technology for the majority of applications in most parts of the world. Absorber size ranges from less than 100 MW to more than 1,000 MW, with 250 MW absorbers being common in every supplier's experience. Nearly 20 suppliers have supplied major systems over the last 25 years, with at least seven of those currently doing credible business in the US today:

- Advatech (J/V of URS, Mitsubishi)
- Alstom Power Environmental (formerly ABB Environmental)
- Babcock & Wilcox
- Babcock Power Environmental (formerly Babcock Borsig, Riley)
- Black & Veatch (Chiyoda Process)
- Hitachi America
- Wheelabrator Air Pollution Control

1.1.4 Process Advantages

Wet FGD has the following advantages when compared to the CDS process:

1. Much lower consumption of reagent
2. Commensurately less by-product to place in landfill.
3. Unlike by-product from earlier, naturally-oxidized wet processes, fully-oxidized gypsum by-product is stable for landfill purposes and can be disposed of in a landfill adjacent to flyash.
4. Potentially, some gypsum by-product may be sold or donated as conditioner for acidic soil, as filler for concrete or as raw material for plaster or stucco depending on local needs.
5. Wet FGD systems will scrub over 50% of the incoming mercury, if it is in the oxidized form which happens when fuels have a high chlorine content. PRB coals typically have lower chlorine content thus not as much elemental mercury is oxidized.
6. Northeastern Wyoming is a dry, windy environment. Wet FGD does not contribute significant dust from the reagent preparation, the process or the by-product handling. The non-dusty gypsum cake will be easier to place on windy days.
7. This technology presents low process risk, low project risk and low schedule risk. System vendors, equipment suppliers, construction contractors, operators and maintenance staff are familiar with this technology.

1.1.5 Process Disadvantages

The process disadvantages are generally the converse of the advantages shown in 1.2.4, below; other disadvantages are:

1. Wet FGD consumes more water than the CDS, approximately 25 – 35% more.

2. Wet FGD may have issues with emissions of sulfuric acid mist, which may affect the long-range visibility model. The dense moisture plume may create a strong visible signature, which impacts CALPUFF modeling.

1.2 CIRCULATING DRY SCRUBBER DESCRIPTION

Circulating dry scrubber (CDS) technology is a dry scrubbing process that is generally used for low-sulfur coal. However, a unique feature is that CDS can achieve very high removal (99% or higher), even at higher inlet sulfur, if high reagent consumption can be tolerated. Similar to spray dryer flue gas desulfurization (FGD), the CDS system is typically located after the air preheater, and the waste products are collected in a baghouse or electrostatic precipitator (ESP). Several minor variations on the CDS technology are offered by three process developers. Lurgi Lentjes offers the technology under the generic name "CDS"; Babcock Power offers the technology under "Turbosorp™ FGD"; and Wulff Deutschland GmbH offers the technology under "GRAF-WULFF."

Flue gas is treated in an absorber by exposing the gas stream counter-currently to a mixture of hydrated lime and recycled by-product. The water is injected in the absorber above the venturi to maintain a temperature of approximately 160°F. The gas velocity in the absorber is maintained to develop a fluidized bed of particles in the absorber. The sprayed water droplets evaporate, cooling the gas at the inlet from 300°F or higher to approximately 160°F, depending on the relationship between approach to saturation and removal efficiency. The lime/recycle mixture absorbs SO_2 from the flue gas and forms calcium sulfite and calcium sulfate. The desulfurized flue gas passes out of the absorber, along with the particulate matter (reaction products, unreacted hydrated lime, calcium carbonate, and the fly ash) to the baghouse.

The CDS technology is similar to other wet and dry FGD technologies in that solids are continuously recycled to the absorber to achieve high utilization of the reagent. However, CDS has a distinctive feature in that material also recirculates within the absorber to achieve a high retention time. It is this circulation that makes high removal efficiency possible with such a dry process, and for this reason the process is called Circulating Dry Scrubber.

1.2.1 Process Chemistry

The SO_2 absorbed in the moist particles reacts with the lime to form calcium sulfite ($CaSO_3$) in the following reaction:

$$SO_2 + CaO + 1/2\ H_2O \Rightarrow CaSO_3 \bullet 1/2\ H_2O$$

A part of the $CaSO_3$ reacts with oxygen in the flue gas to form calcium sulfate ($CaSO_4$):

$$CaSO_3 + ½O_2 + 2H_2O \Rightarrow CaSO_4 \bullet 2H_2O$$

A small amount of carbon dioxide also reacts with hydrated lime to form calcium carbonate:

$$Ca(OH)_2 + CO_2 \Rightarrow CaCO_3 + H_2O$$

1.2.2 Reagents and Waste Products

Limestone is not a viable reagent for the CDS system. Preparation of the hydrated lime involves an atmospheric lime hydrator. The hydrated lime also can be purchased as a reagent; however, converting commercially available lime into hydrated lime on the plant premises offers a low-cost solution. The hydrated lime is stored in a day silo for later use. Typically, the hydrated lime is fed to the absorber by means of a rotary screw feeder, though a gravimetric feeder may be evaluated for more consistent control. The reagent is fed to the absorber to replenish hydrated lime consumed in the reaction, and the feed rate is typically controlled based on the removal efficiency required.

The waste product contains $CaSO_3$, $CaSO_4$, calcium hydroxide, calcium carbonate, and ash.

1.2.3 Commercial Status

CDS systems are in operation at many facilities ranging in size from less than 10 MW to 300 MW (multiple modules are required for plants greater than 300 MW in capacity).

CDS is commercially available from three process developers/vendors:

- Babcock Power

- Lurgi Lentjes
- Wulff Deutschland GmbH

Wulff is currently attempting to create a business partnership to commercially offer their technology in the US. Each of the other vendors was asked for its position with respect to the guarantees necessary for the success of the Dry Fork Station. The hypothetical guarantee posed to Babcock Power and LLNA was 98% removal from a 2.00 lb SO_2/MBtu influent to achieve 0.04 lb SO_2/MBtu emission. This would leave margin for higher sulfur coal at the inlet and margin for a higher permit value at the outlet. In other words, if the commercial blend drifts as high as 2.00 lb SO_2/Mbtu, operation would still be within the permit. Both vendors answered in the affirmative.

Recent information indicates that Lurgi may have exited the CDS market in Europe, dispersing the CDS personnel among other Lurgi business units. LLNA has a set of documentation for the technology, but assistance from personnel in Europe will no longer be available. LLNA has also indicated that Lurgi has sold 80% of LLNA. See the attached summary of vendor survey information in Appendix 5.4

1.2.4 Process Experience

Each of the vendors was interviewed by telephone. Likewise, their users were interviewed. Logs of the telephone conversations are included in the Appendix. Each vendor was asked for a list of installations. Experience is summarized as follows:

Babcock Power

Plant Name	Size	Inlet Sulfur	Removal	SR	Year
Zeltweg/Austria (AEE with Lurgi)	137 MW	2,000 mg/m^3 (~700 ppm)	92.5 %	1.5	1994
St. Andrä/Austria (AEE with Lurgi)	110 MW	2,000 mg/m^3 (~700 ppm)	92.5 %	1.2	1994
Chateaudun/France (by von Roll)	incinerator	1,000 mg/m^3 (~350 ppm)	97.5 %	1.95	1998
Strakonice/Czech (AEE with Wulff)	~68 MW	4,200 mg/m^3 (~1,500 ppm)	92.5 %	1.5	1999
Perpignan/France (by von Roll)	incinerator	1,000 mg/m^3 (~350 ppm)	97.5 %	2.0	2003
Arnoldstein/Austria (AEE)	incinerator	1,500 mg/m^3 (~500 ppm)	97.5 %	1.85	2004
Eferding/Austria (AEE)	incinerator	1,900 mg/m^3 (~650 ppm)	97.5 %	1.5	2005
AES Greenidge 4/Dresden, NY (BPEI)	104 MW	5,000 mg/m^3 (~1,750 ppm)	95+ %	1.8	LOI

Lurgi Lentjes

Plant Name	Size	Inlet Sulfur	Removal	SR	Year

Schwandorf B/Germany	100 MW	4,250 mg/m^3 (~1,500 ppm)	95 %	*	1984
Borken/Germany	~200 MW	13,000 mg/m^3 (~4,500 ppm)	97 %	*	1987
Siersdorf/Germany	2 x ~95 MW	2,700 mg/m^3 (~950 ppm)	93 %	*	1988
GM (Opel)/Germany	eq. 47 MW	2,700 mg/m^3 (~950 ppm)	92 %	*	1990
Zeltweg/Austria (with AEE)	157 MW	2,400 mg/m^3 (~850 ppm)	92 %	*	1993
St. Andrä/Austria (with AEE)	117 MW	2,500 mg/m^3 (~800 ppm)	92 %	*	1994
Simpson 2/Gillette, WY (with EEC)	80 MW	3,900 mg/m^3 (~1,350 ppm)	98 %	*	1995
Roanoke Vly 2/Weldon, NC (w/EEC)	45 MW	3,850 mg/m^3 (~1,350 ppm)	93 %	*	1995
Usti n. L./Czech	~75 MW	2,920 mg/m^3 (~1,000 ppm)	93 %	*	1998
Guayama/Puerto Rico (with EEC) (after FBC)	2 x 250 MW	360 mg/m^3 (~125 ppm)	92 %	*	2002
Treibacher Industrie/Austria	kiln	14,000 mg/m^3 (~4,900 ppm)	99.7 %	*	2002
Lanesborough/Ireland (after FBC)	100 MW	3,000 mg/m^3 (~1,050 ppm)	93.3 %	*	2004
Shannonbridge/Ireland (after FBC)	150 MW	7,000 mg/m^3 (~2,450 ppm)	97.1 %	*	2004
Yushe/China	2 x 290 MW	3,450 mg/m^3 (~1,200 ppm)	90 %	*	2004

* -- Data not provided

Wulff

Plant Name	Size	Inlet Sulfur	Removal	SR	Year
Geilenkirchen-Teveren/Germany	20 MW	*	90%	*	1989
Dessau/Germany	2 x ~44 MW	7,900 mg/m^3 (~2,750 ppm)	96%	*	1997
Theiss B/Austria (oil fired)	275 MW	3,400 mg/m^3 (~1,200 ppm)	97%	*	2000
Strakonice/Czech (with AEE)	~75 MW	4,250 mg/m^3 (~1,500 ppm)	98+ %	*	1998
Hengyun/China	210 MW	2,200 mg/m^3 (~750 ppm)	85+%	*	2002
Zhangshan/China	2 x 300 MW	*	85 – 95%	*	2004 2005
Gujiao/China	2 x 300 MW	*	85 – 95%	*	2005
Pengcheng/China	2 x 300 MW	*	85 – 95%	*	2004 2005
Qingshan/China	2 x 200 MW	*	90 – 95%	*	2005
Xinhai/China	2 x 330 MW	*	92 – 99%	*	2005
Zhangye/China	2 x 300 MW	*	92 – 99%	*	
Haibowan/China	2 x 330 MW	*	92 – 99%	*	2005
Hebi/China	2 x	*		*	

	300 MW		92 – 99%		2005
Hengyun II/China	2 x 300 MW	*	90+%	*	2005

* -- Data not provided

These excerpts focus on units that are large, coal-fired, high sulfur and/or high removal

1.2.5 Process Advantages

The CDS process has the following advantages when compared to wet limestone FGD technology:

1. The absorber vessel can be constructed of unlined carbon steel, as opposed to lined carbon steel or solid alloy construction for wet FGD. For units less than 300 MW, the capital cost is typically lower than for wet FGD. For units larger than 300 MW, multiple module requirements typically cause the CDS process to be more expensive than the wet FGD process.
2. Pumping requirements and overall power consumption are lower than for wet FGD systems.
3. Waste produced is in a dry form and can be handled with conventional pneumatic fly ash handling equipment.
4. The waste is stable for landfill purposes and can be disposed of concurrently with fly ash.
5. The CDS system uses less equipment than does the wet FGD system, resulting in fixed, lower operations and maintenance (O&M) labor requirements.
6. The pressure drop across the absorber is typically lower than wet FGD systems.
7. High chloride levels improve (up to a point), rather than hinder, SO_2 removal performance.
8. Sulfur trioxide (SO_3) in the vapor above approximately 300°F, which condenses to liquid sulfuric acid at a lower temperature (below acid dew point), is removed efficiently with CDS. Wet limestone scrubbers capture less than 25% to 40% of SO_3 and may require the addition of a wet ESP, or hydrated lime injection, to remove the balance of SO_3. Otherwise, the emission of sulfuric acid mist, if above a threshold value, may result in a visible plume after the vapor plume dissipates.
9. Flue gas following a CDS is not saturated with water (30°F to 50°F above dew point), which reduces or eliminates a visible moisture plume. Wet limestone scrubbers produce flue gas that is saturated with water, which would require a gas-gas heat exchanger to reheat the flue gas if it were to operate as a dry stack. Due to the high costs associated with heating the flue gas, all recent wet FGD systems in the United States have used wet stack operation.
10. CDS systems have the capability of capturing a high percentage of gaseous mercury in the flue gas if the mercury is in the oxidized form. The major constituent that will influence the oxidation level of mercury in the flue gas has been identified as chlorine. Considering the typical level of chlorine contained in coals in the United States, we can expect that CDS systems applied to high-chlorine bituminous coals will tend to capture a high percentage of the mercury present in the flue gas. Conversely, CDS systems applied to low-chlorine sub-

bituminous coals and lignite will not capture a significant amount of the mercury in the flue gas.

11. There is no liquid waste from a CDS system, while wet limestone systems may produce a liquid waste stream, especially if the gypsum is to be sold for wallboard. In some cases, a wastewater treatment plant must be installed to treat the liquid waste prior to disposal. The wastewater treatment plant produces a small volume of solid waste, rich in toxic metals (including mercury) that must be disposed of in a landfill. The humidification stream of a CDS system provides a way to achieve a dry by-product from process wastewater from other parts of the plant when processing residue for disposal.

1.2.6 Process Disadvantages

The CDS process has the following disadvantages when compared to limestone wet FGD technology:

1. The CDS process uses a more expensive reagent (hydrated lime) than limestone-based FGD systems, and the reagent has to be stored in a steel or concrete silo.

2. Reagent utilization is lower than for wet limestone systems to achieve comparable SO_2 removal. The lime stoichiometric ratio is higher than the limestone stoichiometric ratio (on the same basis) to achieve comparable SO_2 removal.

3. CDS produces a large volume of waste, which does not have many uses due to its properties, i.e., permeability, soluble products, etc. Researchers may yet develop some applications where the CDS waste can be used. Wet FGD can produce commercial-grade gypsum.

4. Combined removal of fly ash and waste solids in the particulate collection system precludes commercial sale of fly ash if the unit is designed to collect FGD waste and fly ash together.

5. The CDS process is applicable mostly for base-load applications, as high velocities are required to maintain the bed in suspension. The standard design includes provisions for ID fan recycle to mitigate this shortcoming. At Black Hills Neil Simpson, bleed flow from the FD fans is used to mitigate this shortcoming.

1.3 PROCESS VARIATIONS

1.3.1 Flash Dryer FGD

Flash dryer FGD is a technology with many similarities to the CDS. It is located at the same point in the flue gas stream (after SCR and air heater, but before particulate collector and ID fan) and similarly recycles its dry product from the particulate collector back to the injection point. Distinct from the CDS, a flash dryer does not attempt to maintain a churning fluidized bed. The reactor is designed to perform rapid absorption of SO_2 into the particles during the particle's ascent through the tall reactor. Also, the necessary moisture is blended with the particles just prior to admission to the reactor, as opposed to the CDS where the moisture is added to the reactor separately. A performance distinction is that the CDS can reach 0.04 lb SO_2/MBtu, the lower limit for the flash dryer FGD is 0.046 lb SO_2/Mbtu, according to Alstom.

Flash dryers are offered by Alstom Power and Beaumont Environmental.

1.3.2 FBC/Dry Scrubber Combination

A fluidized bed combustor (FBC) offers many advantages when combusting difficult fuels. It generates less NO_X than a pulverized coal-fired boiler and has substantial inherent SO_2 removal. A decade ago, FBC represented best available control technology (BACT) for these pollutants; however, BACT continues to advance. To achieve the level of desulfurization necessary for this project, supplemental post-combustion desulfurization is necessary. Fortunately, either a CDS or a flash dryer makes a perfect companion to the FBC. The boiler receives inexpensive limestone and calcines it to lime. Part of the lime is consumed in absorbing sulfur compounds in the FBC. The resulting mixture of ash, calcium sulfite and lime is then forwarded to the CDS and used as reagent there. The remaining lime in this mixture is an excellent reagent for the CDS.

Unfortunately, SO_2 is only half the concern. FBC (even with SNCR) may not achieve BACT status for NO_X without further post-combustion cleanup. Selective catalytic reduction (SCR) in the popular high-dust configuration is not feasible for FBC because the dust carryover contains excessive calcium, which would harm the catalyst. Any SCR catalyst would have to be installed after the baghouse, in the low-dust configuration. The low dust SCR configuration involves substantial additional capital and O&M cost. For the situation at Dry Fork, a FBC boiler would require similar post-combustion emission controls to a pulverized boiler. The additional capital cost of the FBC boiler produces no technical, environmental or O&M cost advantages. For this reason, and because there is little experience with FBC on PRB fuel, FBC combinations were not given further consideration in this study.

1.4 PROCESS COMPARISON

The two processes evaluated here achieve the desired results through very different mechanisms, which results in cost characteristics that are polar opposites. The Wet FGD process has a great deal of large equipment made of specialized materials. Capital cost is higher. However, the wet process is very efficient, cleaning the flue gas with a minimum of reagent and producing a minimum of by-product. On the other hand, the CDS system requires less equipment, which is made of ordinary materials such as carbon steel, rather than corrosion-resistant materials, such as alloy. The capital cost is lower, but the process is an inefficient user of reagent when pushed past 95% removal. At high removal rates, it also produces much larger quantities of by-product.

On other issues, Sargent & Lundy expects the processes to perform very similar to one another. Sensitivity to reagent quality becomes an issue when the required performance is at such a high level. Reagents can vary according to the deposit. Although spray dryer FGD systems suffer some sensitivity to sudden variations in the lime quality, the two processes evaluated here are less sensitive. Both the wet FGD and the CDS operate with a substantial inventory of reagent in-process.

Sensitivity of the process is an important consideration. With any control system, the monitored variable varies within a control band. The width of the control band depends both upon the sensitivity of the process itself and the sensitivity of the instrumentation in the control loop. Both the wet FGD system and the CDS system operate with large volumes of in-process material. In wet FGD, this is typically 10 to15 hours, providing substantial dampening of any upsets in gas flow, inlet SO_2 concentration or reagent quality. Although the CDS has less material in process, it has a major advantage over the spray dryer in that the humidification function is performed separately from the introduction/recycling of solids. Upsets in water feed do not affect the volume of reactive material in play, and vice-versa. Thus, either of the processes considered here will exhibit tighter control than would a spray dryer FGD.

Performance figures in this report are generally those for which guarantees may be offered. Various sources may cite higher figures for these technologies, but Sargent & Lundy does not believe that higher values are currently being offered commercially. Of course, the absolute nature of an operating permit is such that it is untenable to try to operate a plant with permit values that are as restrictive as available guarantees.

2. CAPITAL COST EVALUATION

2.1 FACILITY DESIGN

The capital cost evaluation compares costs for two emission control facilities, one using Wet FGD and the other using a Circulating Dry Scrubber. Each is designed to clean the flue gas from a boiler using either of the two coals specified in Table 2.1-1.

TABLE 2.1-1
FUEL DATA

Fuel	Dry Fork Commercial – Powder River Basin	Dry Fork Blend – Powder River Basin
Fuel analysis, % wt:		
Moisture	32.06	32.06
Ash	4.77	10.00
Carbon	33.1	47.22
Hydrogen	3.23	3.23
Nitrogen	0.72	0.72
Sulfur	0.33	0.65
Oxygen	11.67	11.67
Chlorine	0.10	0.10
High heating value, Btu/lb	8,045	7,500
SO_2 generation, lb/Mbtu	0.83	1.63

The emission control design paramaters for the two estimated facilities are presented in Table 2.1 -2.

TABLE 2.1 –2
STUDY FGD DESIGN BASIS

	Wet FGD	CDS
Unit capacity	250 MW	250 MW
Heat input to boiler, MBtu/hr	2,632	2,632
Fuel	Dry Fork Commercial – Powder River Basin	Dry Fork Commercial – Powder River Basin
Uncontrolled SO_2, lb/MBtu	0.83	0.83
SO_2 emission, lb/MBtu	0.06	0.06
SO_2 removal, %	92.7	92.7
By-product	Dry waste	Dry waste
Power consumption, % MW	2.12 5.3	1.12 2.8
Reagent	High-calcium limestone	High-calcium lime
Reagent cost, $/ton	25	70
Reagent purity, %	94	91
Reagent stoichiometry, moles of CaO/mole of sulfur	Inlet basis 0.97 removed basis 1.05	inlet basis 1.4 removed basis 1.51
Load factor	85	85

2.2 SYSTEM DESIGN (SUBSYSTEMS)

The FGD system overall design consists of the following subsystems:

2.2.1 Reagent Preparation System

Lime for CDS: Reagent is received by truck and pneumatically conveyed to storage. Lime is stored in a 14-day capacity bulk storage lime silo. The lime is pneumatically conveyed to a 16-hour capacity day bin. The lime day bin and a gravimetric feeder supply the lime to a 150% atmospheric hydrating system. This will allow two-shift operations for the unit operating continuously at 100% load. A conventional commercially available atmospheric lime hydrator is used. The equimolar amount of water is added to the hydrator to convert lime into hydrated lime. The hydrated lime is pneumatically transported to a hydrated lime day silo (16-hour capacity). The hydrated lime is fed to the CFB absorber with a rotary screw feeder or other appropriate feeding device.

Limestone for Wet FGD: Reagent is received by dump truck and stored in a 14-day pile. Limestone is fed by belt conveyor to a day silo at each of two ball mills. A gravimetric feeder controls limestone feed to the wet milling operation. Mill product pumps deliver the product to cyclone classifiers that separate the stream into coarse for re-grinding and acceptable grind for the storage tank. The storage tank maintains a 12-hour supply of limestone slurry, which is supplied to the absorber/reaction tank by a recirculating loop.

2.2.2 Absorber/Reaction System

CDS System: One absorber, is provided to achieve 98% SO_2 removal efficiency in the absorber and baghouse. The absorber is a CFB reactor where the solids are fluidized by the updraft of the flue gas. The pressure drop across the absorber will be approximately 8 to 10" w.c. The flue gas is introduced to the absorber through a venturi to facilitate the fluidization. The water is injected into the tower above the venturi using high-pressure atomizers. The absorber is a carbon steel absorber. The absorber will be operated at approximately 30°F adiabatic approach to saturation temperature. The hydrated lime, along with the recycle waste, is introduced just above the venturi. The counter-current flow thus offers large residence time and significant turbulence to enhance particle flue gas interaction to achieve high SO_2 reduction efficiency. The particle interaction also helps remove the layer of product formed on the particle surface enhancing the reagent utilization.

Wet FGD System: A single absorber treats 100% of the flue gas to achieve 97.5% SO_2 removal. The absorber is an open spray tower with integral reaction tank forming the bottom. The absorber has multiple layers of spray nozzles fed by five large slurry pumps that take suction from the reaction tank portion. This achieves a recycling of the slurry that provides a large quantity of fine droplets to absorb the SO_2 from the flue gas. The reaction tank is agitated and has spargers that provide a large quantity of oxidation air. This drives the reaction of SO_2 with the calcium ions from the limestone and with the excess oxygen from the air to the desired gypsum by-product. The vessel is typically alloy material, lined carbon steel or FRP. Piping is typically high-grade FRP, often changing to alloy inside the vessel.

2.2.3 By-Product Management System

CDS System: The waste is collected in the baghouse. A portion of the waste is stored in a recycle storage silo, which is then used to mix with fresh reagent to increase the overall reagent utilization. Pug mills (2 x 100%) or other appropriate mixing devices are provided to treat the CDS waste before it is loaded onto the trucks for disposal or sale.

Wet FGD System: A pump bleeds by-product from the reaction tank to the dewatering system. Primary dewatering is by hydrocyclones, which send the weak suspension of fine gypsum back to the reaction tank and forward the densified slurry to a vacuum filter for a second stage of dewatering. The vacuum filter produces a cake dry enough to landfill. The cake is conveyed to a stackout pad where it can be loaded into dump trucks. The filtrate is returned to the reaction tank. At the chlorine levels of this coal, sufficient chloride will leave the system with the by-product that no chloride purge would be necessary to maintain an acceptable chloride level in the scrubbing slurry. If landfill restrictions require that the chlorides be washed from the by-product, a portion of the reclaimed water must be purged. The water can be disposed of as-is if it meets local water discharge requirements; if not, it must be treated, probably for suspended solids.

2.2.4 Baghouse

CDS System: A knockdown chamber, followed by a conventional pulsejet baghouse with an air-to-cloth ratio of 3.2, is included in the estimate. The baghouse is provided with a spare compartment for offline cleaning to ~~maintain the opacity at 10% or less. The waste is pneumatically conveyed to a waste storage silo with a typical 3-~~ day storage capacity, which is in accordance with typical utility design.

Wet FGD System: A conventional pulsejet baghouse with an air-to-cloth ratio of 4.0, is included in the estimate. The baghouse is provided with a spare compartment for offline cleaning to maintain the opacity at 10% or less. The ash is conveyed to a storage silo with a typical 3-day capacity. The ash may be sold or disposed of.

2.2.5 Flue Gas System/Stack

The flue gas from the air preheater passes through the particulate collection and FGD absorber(s). In the case of wet FGD, the flue gas passes through the baghouse, then the absorber; in the case of the CDS, the flue gas passes through the absorber(s) first, then the baghouse. The ID fan sizing includes about 10" H_2O (7" operating) pressure drop (wet FGD) or 16" H_2O (14" operating) pressure drop (CDS) through the absorber and baghouse. The flue gas is exhausted through a chimney with a concrete shell surrounding a top-hung flue. In the wet FGD case, the flue would be fiberglass, compatible with the wet condition of the flue gas. For the CDS case, the flue would be carbon steel.

2.2.6 Support Equipment and Miscellaneous

The general support equipment includes typical balance-of-plant sub-systems, such as instrument air compressor, makeup water system, control room, etc. Equipment considered as miscellaneous includes onsite electrical power equipment, such as transformers and grounding, which is required to supply electrical power to the FGD system.

2.3 CAPITAL COST COMPARISON

Table 2.2–1 compares the capital costs estimated for these two types of FGD systems.

TABLE 2.2-1
CAPITAL COST COMPARISON

	Wet Limestone FGD	CDS
Reagent Preparation System	$4,710,000	$3,335,000
Absorber/Reaction System	9,896,000	8,485,000
By-Product Management System	3,970,000	2,501,000
Baghouse	9,764,000	11,837,000
Flue Gas System/Stack	9,150,000	5,318,000
Support Equipment and Miscellaneous	2,960,000	1,750,000
Total Process Capital	$40,450,000	$33,226,000
General Facilities (5% of TPC)	2,023,000	1,661,000
Engineering and Construction Mgt (20% TPC)	8,090,000	6,645,000
Project Contingency (20% TPC, General Facilities, Engineering & Construction Management)	10,113,000	8,307,000
Total Plant Cost	$60,676,000	$49,839,000

Notes:
1. Source of information is the Sargent & Lundy database, accumulated from completed projects and updated using recent supplier proposals.
2. Accuracy of estimate ± 20%
3. Labor cost based on single-shift operation
4. ID fan and electrical costs are incremental (a portion of the fan and switchgear cost equal to the portion of the pressure drop attributable to the emission controls, is included)

3. OPERATING AND MAINTENANCE COST

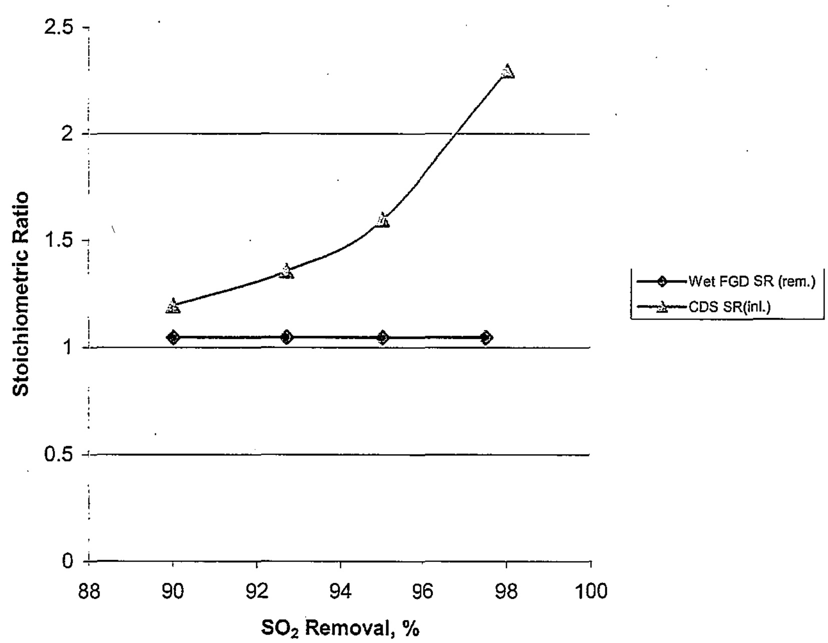
Operating and maintenance cost is dominated by cost of reagent and labor. In comparing these two FGD processes, there are smaller but significant differences in use of auxiliary power and fabric filter bag life replacement costs, so those are reviewed here as well.

3.1 REAGENT COST

Reagent cost is the single largest distinction between these processes. Unlike the spray dryer FGD, the CDS can achieve the 98% SO_2 removal needed for the sulfur spikes expected at the northeastern Wyoming plant. However, unlike the wet FGD system, the stoichiometric ratio necessary to achieve this level of performance escalates dramatically at high removal rates. Wet FGD is shown limited to 97.5% removal because suppliers advise the process can achieve no lower than 0.04 lb. SO_2/MBtu. CDS operators advise that the scrubber can run to 100% SO_2 removal, although reagent consumption becomes extremely high. For reference, if the uncontrolled SO_2 rate is 1.21 lb/MBtu and the permit rate is 0.08 lb/MBtu, the FGD system will have to remove over 93% of the SO_2 just to reach the permit limit. When burning this higher SO_2 coal, the FGD will have to control to some level lower than 0.08lb/MBtu to allow for some margin for system transients, thus approaching >95% removal, day in and day out.

Table 3.1-1 STOICHIOMETRIC RATIO VS. REMOVAL EFFICIENCY		
SO_2 Removal Efficiency, %	**Wet FGD SR(rem.)**	**CDS SR(inl.)**
90	1.05	1.2
92.7	1.05	1.4
95	1.05	1.6
97.5	1.05	--
98	N/A	2.3

Notes:
1. Conventional notation for wet FGD is moles reagent per mole SO_2 removed.
2. Conventional notation for "dry" FGD is moles reagent per mole inlet SO_2. Divide inlet basis SR by removal efficiency to find removed basis SR.
3. Based on 0.83 lb SO_2/MBtu
4. CDS values are Sargent & Lundy estimated values.

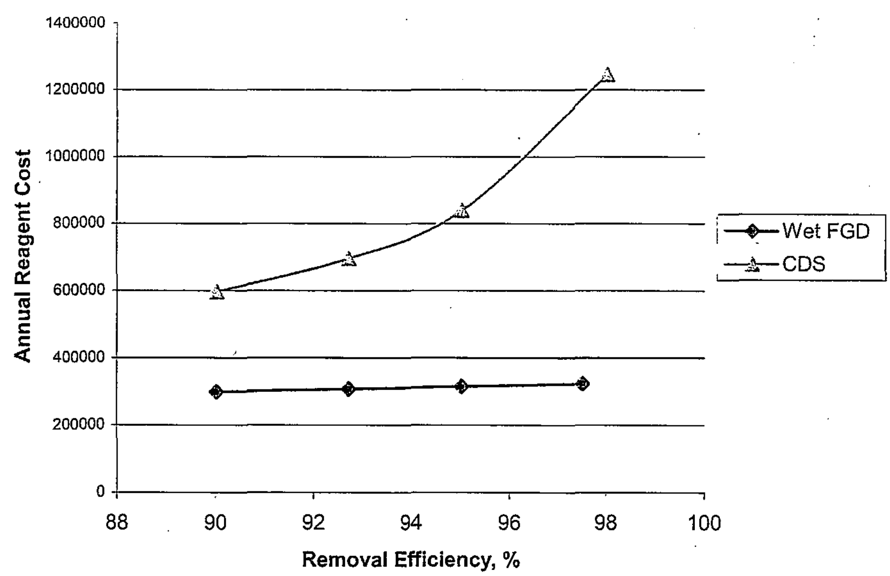


Stoichiometric ratio relates to cost as shown in Table 3.1-2.

TABLE 3.1-2
ANNUAL REAGENT COST VS. REMOVAL EFFICIENCY

SO_2 Removal Efficiency, %	Wet FGD Limestone Cost, $/year	CDS Lime Cost, $/year
90	$300,000	$598,000
92.7	$309,000	$719,000
95	$317,000	$842,000
97.5	$325,000	--
98	N/A	$1,249,000

Notes:
1. Based on limestone at $25/ton and 94% $CaCO_3$; lime at $70/ton and 91% CaO
2. Based on 250 MW, 85% capacity factor



3.2 FGD AUXILIARY POWER

Scrubbing consumes a great deal of electricity. Wet scrubbing achieves its excellent utilization of the reagent largely through applying greater energy to the absorption process. Auxiliary power is compared in Table 3.2-1.

TABLE 3.2-1
AUXILIARY POWER COMPARISON

	Wet FGD	CDS
Absorber ΔP	7 in. H_2O	8 in. H_2O
ID Fan Incremental kW	1,125 kW	1,290 kW
Recycle L/G	90	--
Recycle Pump kW	1,250 kW	--
Other FGD Auxiliaries	2,925 kW	1,550 kW
Total FGD Auxiliary Power kW	5,300 kW	2,800 kW
Annual Auxiliary Power Cost	$1,173,000	$614,000

Notes:
1. based on 250 MW unit, 0.83 lb SO_2/MBtu, 92.7% SO_2 removal
2. based on 2.96¢/kWh

3.3 COMPARATIVE LIFE OF FABRIC FILTER BAGS

In the wet FGD system, the baghouse removes the fly ash upstream of the scrubber where it is transported directly to disposal. Recycle of scrubbing media is handled by pumping slurry made from limestone. The fly ash is not used as a source of reagent.

In the CDS system, the baghouse is in the scrubber recycle loop. It collects not only ash, but also all the FGD by-product. Furthermore, the by-product is recycled to the fluidized bed absorber to improve utilization of the scrubbing media, so the baghouse collects particles on average three or more times. This means the dust loading is 3 to 4 times higher than for the wet FGD system and the bags must be cleaned much more frequently. Ultimately, this leads to greater bag wear and more frequent scheduling of replacement of the suit of bags, along with corroded bag support baskets. Table 3.3-1 provides Sargent & Lundy's estimate of this impact.

TABLE 3.3-1 BAG LIFE COMPARISON		
	Wet FGD	**CDS**
Baghouse A/C ratio	4.0	3.2
Estimated Bag Life	3.0 years	2.5 years
Suit of Bags – Installed Cost	$531,000	$558,000
Average Annual Cost of Bags	$177,000	$223,000

based on 250 MW unit, 10% ash, 92.7% SO_2 removal, 85% capacity factor, pulse-jet baghouse

3.4 TOTAL O&M COSTS

Sargent & Lundy's estimate of annual operating and maintenance costs for the two scrubber types is shown in Table 3.4-1. Reagent cost, auxiliary power cost and bag replacement cost are carried down from Tables 3.1-1, 3.2-1 and 3.3-1.

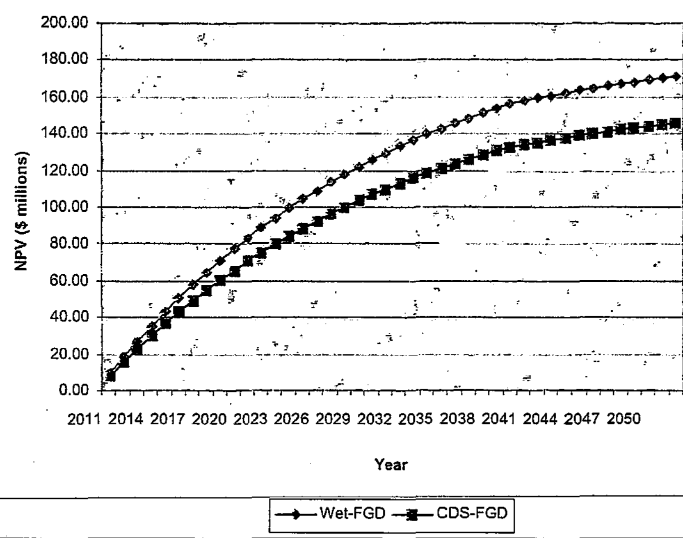
TABLE 3.4-1 ANNUAL O&M COST COMPARISON		
	Wet FGD	**CDS**
Operating Labor	$520,000	$520,000
Maintenance Materials	$971,000	$748,000
Maintenance Labor	$647,000	$498,000
Administrative and Support Labor	$350,000	$305,000
Total Fixed O&M Costs	$2,488,000	$2,071,000
Reagent Cost	$309,000	$719,000
By-Product Disposal Cost	$203,000	$195,000
Auxiliary Power Cost	$1,173,000	$614,000
Fabric Filter Bag Replacement	$177,000	$223,000
Water Cost	$134,000	$89,000
Total Variable O&M Costs	$1,996,000	$1,840,000
Total Annual O&M Costs	$4,484,000	$3,911,000

based on 250 MW unit, 0.83 lb SO_2/MBtu coal, 92.7% SO_2 removal, 0.06 lb SO_2/MBtu emission, 85% capacity factor

4. CONCLUSION

For the very high SO_2 removal regime that is being considered for the Dry Fork Station, a spray dryer FGD, which was the traditional approach to low-sulfur scrubbing, is not feasible. The alternatives with commercial experience are wet limestone/forced oxidation FGD, producing a gypsum by-product and a separate fly ash stream; or circulating dry scrubber (CDS), producing a by-product that includes the fly ash and significant amount of excess lime. The wet FGD uses a reagent with much lower cost, and at 92.7% SO_2 removal, uses it more efficiently. However, the capital cost of the wet FGD is much higher. Conversely, the CDS has much lower capital cost, while the annual reagent costs are much higher, but the total operating cost, at the 92% to 95% removal rates, is less for the CDS due to lower auxiliary power and lower maintenance costs. The practical limit for a Wet FGD on low sulfur coal is 97.5% reduction or a "floor" of 0.04 lb SO_2/MBtu outlet emission rate. The CDS system is capable of even higher removal rates than the Wet FGD (lower outlet emission rates), but the reagent usage increases as shown in earlier charts. Table 4.1 summarizes the present value of the capital and O&M costs provided in previous tables (2.2-1 and 3.4-1). As part of the preparation of this report, the CDS and Flash Dryer vendors where surveyed regarding their experience and interest in this project. Appendix 5.4 provides a summary of their responses.

Table 4.1
Present Value Cost Comparison - 30 Year Debt Amortization



DEQ/AQD 001915

Sargent & Lundy ranks the technologies as follows:

1. The Circulating Dry Scrubber (CDS) meets all the objectives of the study, is available at low capital cost, has acceptable reagent consumption and low consumption of water and auxiliary power. As a result, it will produce the lowest lifetime cost.
2. The Wet Limestone/Forced Oxidation/Gypsum FGD (Wet FGD) would cost more to build and would consume significantly more water. The lower reagent cost does not offset these significant disadvantages.
3. The Spray Dryer FGD system has similar attraction to that of the CDS, but based on the study parameters, the Spray Dryer FGD cannot achieve the design performance for all the desired cases.

If the permit limit were eased to 0.08 to 0.10 lb SO_2/Mbtu, Spray Dryer FGD would be feasible and could be bid competitively with the CDS. With the permit limit at 0.06 to 0.08 lb SO_2/MBtu, S&L recommends the CDS as the preferred emission control system.

4.1 BIBLIOGRAPHY

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3. W. Schüttenhelm, T. Robinson, and A Licata, "FGD Technology Developments in Europe and North America," presented at The Mega Symposium, August, 2001, Chicago.

4. "Budgetary Proposals by Lurgi Lentjes Bischoff," June, 2001.

5. Sargent & Lundy Correspondence With Dr. Rolf Graf, 2003.

5. APPENDIX: VENDOR SURVEY

5.1 USERS

February 14, 2005	Tom Stalcup	Black Hills Power	Gillette, WY
March 2, 2005	Tom Stalcup	Black Hills Power	Gillette, WY
March 2, 2005	Bill Vela	AES Puerto Rico	Guyama, PR
March 2, 2005	Dan Wallach	Dakota Gasification Co.	Beulah, ND
March 2, 2005	Ernst Wagner	Treibacher Industrie	Austria

5.2 SUPPLIERS

March 2, 2005	Rick Sereni	Lurgi Lentjes NA	Columbia, MD
March 2, 2005	Tom Robinson	Babcock Power	Worcester, MA
March 2, 2005	Bill Ellison	Ellison Consultants*	Monrovia, MD
March 15, 2005	Will Goss	Beaumont Environ.	McMurray, PA

* representing Wulff

5.3 CONSULTANT

March 2, 2005	John Toher	d/b/a IJM Consulting*	Columbia, MD

* co-located with Lurgi Lentjes North America

5.4 SUMMARY OF VENDOR INFORMATION

TELEPHONE LOG

February 14, 2005

Participants:

Mike Paul	Basin Electric Power Coop	Bismarck, ND	(701) 355-5691
Bill Siegfriedt	Sargent & Lundy	Chicago, IL	(312) 269-2015
Tom Stalcup	Black Hills Power & Light	Gillette, WY	(307) 682-3771 x-211

Subject: CFB FGD Operating Experience at BHP&L Neil Simpson 2

Mike Paul and Bill Siegfriedt called Tom Stalcup, Plant Manager at Neil Simpson Station to obtain an update on Black Hills' experience with their circulating fluidized bed scrubber.

BOILER AND COAL INFORMATION

Neil Simpson 2 is a B&W opposed-fired PC boiler with no reheat.
Coal is Wyodak 8,000 Btu/lb., 7 to 7.5% ash, 1.0 lb/MBtu SO_2
Lime comes from Rapid City at $63/ton delivered.

OPERATION

NOx control is by low-NOx burners. There is no SCR.
SO_2 control is by the CFB scrubber, achieving 88% to 94% removal.
Particulate control is by electrostatic precipitator (ESP)
The scrubber has been running since 1995.
The unit is a nominal 80 MW unit, but it consistently achieves 85MWnet.
Availability requirement is 95%; goal is 98%; they beat the goal.
Scheduled outage 1 week every 2 years.
ΔP across the bed is 3 in. to 4 in. water. ID fan has 2500 hp motor.
Temperature is saturation (125° - 128°F) + 30° = 158° - 160°F
Stoichiometric ratio is higher than 1.4

The system is very forgiving.
There is little trouble with material pluggage. Fluidizing stones are essential.
Maintenance cost is low.
Key to success is to clean the hydrator every three days. The water nozzles (600 psi) must be cleaned and checked for wear twice a week. They must be replaced every 3 to 4 months.
Vigilance is required with respect to the ESP casing. Inleakage causes serious corrosion.

BY-PRODUCT

By-product is not sold; it is landfilled.
By-product is conditioned (moistened with a pug mill) when filling trucks. It places well.

TELEPHONE LOG

March 2, 2005

Participants:

Mike Paul	Basin Electric Power Coop	Bismarck, ND	(701) 355-5691
Bill Siegfriedt	Sargent & Lundy	Chicago, IL	(312) 269-2015
Tom Stalcup	Black Hills P&L	Gillette, WY	(307) 682-3771 x-211

Subject: Circulating Dry Scrubber Experience at Neil Simpson 2

This was a follow-up to our call on February 14.

Given BHP's apparent satisfaction with the CDS on Neil Simpson 2, S&L asked why a spray dryer FGD was selected for Wygen 1. BHP advised that the Wygen 1 project was an EPC contract with Babcock & Wilcox. B&W proposed the spray dryer FGD since they are the US licensee for Niro Atomizer.

Since the site has CDS and spray dryer FGD side by side, S&L asked for a comparison. Stalcup advised that the spray dryer is limited to 94% SO_2 removal on PRB coal; whereas the CDS will go as high as necessary. A mine-mouth plant must accommodate spikes in coal sulfur content; the CDS has the margin and the rapid responses to accommodate this, whereas the spray dryer cannot. The spray dryer FGD system has a much higher maintenance cost (¼- to ½-time mechanic) and requires a full-time operator.

BHP identified only one problem area with the CDS technology. Stalcup recommended replaceable wear plates above the tube sheet, as the transition area is subject to erosion. The wear plates should be 3/16" carbon steel.

S&L inquired about the experience with Environmental Elements Corp. Stalcup noted that EEC became insolvent soon after the unit was completed. EEC advised at that time that they would no longer be supporting the unit. Until that time, EEC did a good job. John Toher has as strong a knowledge of the technology as anyone. Dr. Sauer came in from Germany on one occasion. Paul Petty was good.

Stalcup will not be able to spend much time with us at the plant next week, as B&W will be in for meetings on the spray dryer FGD.

TELEPHONE LOG

March 2, 2005

Participants:

Mike Paul	Basin Electric Power Coop	Bismarck, ND	(701) 355-5691
Bill Siegfriedt	Sargent & Lundy	Chicago, IL	(312) 269-2015
Bill Vela	AES Guyama	Puerto Rico	(787) 866-8117 x-239

Subject: Circulating Dry Scrubber Experience at AES Guyama

Bill Vela is the plant Environmental Engineer. The plant has been in service since November, 2002. The Guayama plant has two boilers, each rated at 255 MW gross. The boilers are fluidized bed combustion (FBC) boilers and the flue gas desulfurization (FGD) consists of two circulating dry scrubbers (CDS). Limestone is injected into the furnaces. The fines (now calcined to lime) carry over to the CDS where they are re-used. Spent bed material (coarse) is tapped at the furnace and is not re-used. Lime is injected into the CDS.

The AES permit is based on 1% sulfur, but they are burning 0.6% to 0.7% sulfur coal. The emission limit is 0.022 lb SO_2/Mbtu (9ppm)(54 lb/h). The analyzer between the boiler and the FGD system is troublesome. The NOx limit is 0.10 lb/Mbtu (57 ppm)(246 lb/h). Condensible PM_{10} caused opacity exceedences. AES negotiated a higher limit of 0.3 lb/MBtu.

The limestone is actually Aragonite, a partially-fossilized form of coral. It is mined underwater in the Bahamas and is supplied at $11 - $12/T. Lime, on the other hand, is $200/T. AES has cut usage to the bare minimum. They may try to stop injecting lime altogether.

Guyama achieves 70% to 80% SO_2 removal in the boiler. An electrostatic precipitator was chosen because of the low temperature (they control to 170°F), which creates potential for bag blinding. The precipitator has 407,400 ft^2 of collection area for 840,516 acfm (SCA = 485 ft^2/1000 cfm). There is 70% recycle of the material collected in the ESP back to the CDS. Material is conveyed pneumatically.

The Alstom FBC boilers had trouble with tube leaks in the fluidized heat exchanger.

The CDS cannot operate at less than 50% load. The transition to operation of the CDS is tricky, causing exceedences of opacity and other problems.

Originally, the CDS used waste water that contained high chlorides. This caused a sulfuric acid mist emission problem. The plant water management plan was altered to reduce the mineral content of the scrubber makeup and the problem was resolved.

The scrubber was supplied through Environmental Elements Corp. EEC became insolvent during startup. John Toher (ex-EEC consultant) and others were brought in to help. There was a warranty issue over the opacity problem.

Vela will be retiring in about two months. In the mean time, he would be happy to give a tour of the plant. Vela e-mailed a PowerPoint presentation about the emission controls.

TELEPHONE LOG

March 2, 2005

Participants:

Bill Siegfriedt	Sargent & Lundy	Chicago, IL	(312) 269-2015
Dan Wallach	Dakota Gasification Company	Beulah, ND	(701) 873-2100 x-6598

Subject: Circulating Dry Scrubber Experience at Pilot Plant

The Great Plains Synfuels plant was the host to a CDS pilot plant in the early '90s. The pilot plant was tested on various sulfur levels, simulated by injecting sulfur, and at various removal rates, up to 92%. In testing, Lurgi discovered that salting the water would improve SO_2 removal.

The pilot CDS had problems with circulation.

The CDS was equipped with a baghouse, which suffered from high ΔP due to blinding of the bags. Ash was recycled with aerated slides – these were troublesome.

The process generates lots of SO_3, which is a concern. They did not test for SO_3 removal in the CDS.

The technology was still immature at the time, so there were concerns about reliability and about % removal. When it came time to choose a technology for the full-scale FGD system, they considered wet limestone, but they selected an ammonia scrubber that produces fertilizer.

TELEPHONE LOG

March 3, 2005

From Lurgi's experience list, it was observed that there is one project sold for 99.7% SO_2 removal efficiency. This is at Treibacher Industrie in Austria. S&L called Treibacher for their insights.

Participants:

Bill Siegfriedt	Sargent & Lundy	Chicago, IL	(312) 269-2015
Ernst Wagner	Treibacher Industrie	Austria	(011)(43)(4262) 505-300

Subject: Circulating Dry Scrubber Experience at Treibacher

The CDS at Treibacher operates on a rotary kiln that regenerates catalysts. The offgas contains 14,000 mg/m^3 of SO_2 (nearly 5,000 ppm) and the scrubber reduces this to 50 mg/m^3 (99.64% removal).

Herr Wagner says there was a dispute over stoichiometric ratio, but he did not elaborate.

Herr Wagner provided his estimates of stoichiometric ratios:

Inlet SO_2 Loading	Stoichiometric Ratio
5,000 mg/m^3 (1,750 ppm)	1.5
10,000 mg/m^3 (3,500 ppm)	2.0 to 2.5 (say 2.2)
higher (5,000 ppm)	perhaps 3.0

TELEPHONE LOG

March 2, 2005

Participants:

Mike Paul	Basin Electric Power Coop	Bismarck, ND	(701) 355-5691
Bill Siegfriedt	Sargent & Lundy	Chicago, IL	(312) 269-2015
Rick Sereni	Lurgi Lentjes North America	Columbia, MD	(410) 910-5179

Subject: Circulating Dry Scrubber Capabilities

Rick Sereni is Senior Proposal Manager at LLNA. Most of the staff at LLNA are either ex-EEC or ex-R-C (Environmental Elements Corp. or Research-Cottrell).

Rick highlighted some features of the Lurgi CDS. The CDS has "no moving parts," such as rotary atomizers or slurry pumps. SO_2 removal is not artificially limited because the water is injected separately from the sorbent. Water injection is modulated to control temperature above the flue gas dew point. Sorbent feed is modulated to control SO_2 removal.

ΔP across the bed is about 3 inches.

The process does not rely on the particulate collector for additional SO_2 removal, so the process can be teamed with either an ESP or a baghouse. That said, ammonium bisulfate causes problems in the bags, but an ESP is immune to bisulfate problems.

Mercury can be controlled in a plant that has a CDS.

Rick e-mailed a Lurgi CDS experience list and a CDS brochure.

TELEPHONE LOG

March 2, 2005

Participants:

Mike Paul	Basin Electric Power Coop	Bismarck, ND	(701) 355-5691
Bill Siegfriedt	Sargent & Lundy	Chicago, IL	(312) 269-2015
Tom Robinson	Babcock Power	Worcester, MA	(508) 852-7100

Subject: Circulating Dry Scrubber Capabilities

S&L asked about the source of Babcock Power's CDS technology. Robinson advised that they license it from Austrian Energy & Environment, a former sister company in Babcock Borsig Power.

Babcock Power is completing a sale of CDS to AES for their Greenidge station (a former NYSEG property).

Robinson explained that CDS fills a niche between spray dryer FGD and wet FGD. In particular, the CDS can achieve higher % sulfur removal on high-sulfur coal than can a spray dryer FGD. Stoichiometric ratio is relatively low because of the many passes of recirculation. He felt the curve of stoichiometric ratio is a fairly straight line.

The down side is that CDS has a higher flue gas ΔP than a spray dryer.

The baghouse for a CDS is a little larger than for particulate alone or for a spray dryer due to the heavy particle loading.

The CDS system has low capital cost compared to wet FGD.

Robinson promised to send information if we would e-mail him.

TELEPHONE LOG

March 2, 2005

On March 1, Bill Siegfriedt sent an e-mail to the inquiry address on the Wulff website, inquiring whether Wulff is prepared to offer its technology for US projects. On March 2, a reply call was received from Ellison Consultants.

Participants:

Bill Siegfriedt	Sargent & Lundy	Chicago, IL	(312) 269-2015
Bill Ellison	Ellison Consultants	Monrovia, MD	(301) 865-5302

Subject: Wulff Circulating Dry Scrubber Capabilities

Bill Ellison explained that he is providing liaison services to Wulff. Wulff is currently in negotiation with two firms in the US:

- A potential US licensee
- A potential US teaming partner

Wulff expects to be in a position to be more specific in two weeks. They expect these arrangements to be active by summer.

S&L asked about the possibility that Basin Electric could obtain a project license. Ellison stated that this is also a possibility.

Wulff has recently built the first 300 MW CDS absorber. It is a Austrian retrofit on an existing boiler that is being converted to combined cycle using the "hot windbox" concept. The boiler will receive the gas turbine exhaust at its windbox and fire additional fuel. For one month of the year, the fuel will be residual oil. (Presumably coal the rest of the year) The CDS is designed for 99% removal efficiency.

S&L inquired about stoichiometric ratio. Ellsion replied that SR could be as high as 1.4, maybe 1.5.

Ellison recommended a fluid bed hydrator that permits use of quick lime rather than hydrated lime.

Ellison noted a March, 1995 paper by Keeth and Ireland of Stearns-Roger and Ratcliffe of EPRI titled "Utility Response . . .", which named CDS the most cost-effective technology on PRB.

TELEPHONE LOG

March 15, 2005

Combustion Components Associates (CCA) left a message to contact Will Goss at Beaumont concerning the flash dryer FGD technology formerly represented by RJM.

Participants:

Bill Siegfriedt	Sargent & Lundy	Chicago, IL	(312) 269-2015
Will Goss	Beaumont Environmental	McMurray, PA	(724) 941-1093

Subject: Flash Dryer FGD Capabilities

Goss advised that RJM has closed its doors and Beaumont remains independent. Website is www.besmp.com.

The process is distinguished from spray dryer FGD by basic parameters:

- 0.5% moisture in the by-product, rather than 15% to 20% moisture
- 20 to 25% less lime consumption
- 200°F stack temperature

Beaumont has a patent on flash dryer FGD using a slurry of lime (pebble lime) rather than hydrated lime. They have a patent pending (with Charlie Sedman/ex-EPA) on mercury control using cooling (to 250°F).

He said 98% SO_2 removal on low-sulfur coal would be no problem. Stoichiometric ratio would be "under 2," though SO_3 might have to be added.

He has built scrubbers with absorbers up to 17' diameter. He qualified to bid to Bechtel on a 525 MW project and has a bid pending with Washington Group on the 600 MW PSE&G Hudson 2 (bid 2 x 22' diameter absorbers). He said 250 MW would be easy. He would do it with two absorbers, each 14' to 15' in diameter.

S&L asked about experience. Beaumont listed some past experience:

- Goss designed the Wheelabrator spray dryer FGD when he worked there.
- Hamilton, Ohio; 50 MW; used a now-superseded design to scrub 99%
- Medical College of Ohio 15 MW flash dryer (current design)
- Also small projects at Taiwan Sugar, a coke calciner (40MW equiv.) in India, and a job in Poland
- Currently doing University of Virginia

S&L inquired about commercial backing. Beaumont advised that they have had a relationship since 2000 with Sedgman LLC, a coal washing company. Contracts for Beaumont equipment are written with Sedgman. Sedgman executes the design and support work.

TELEPHONE LOG

March 2, 2005

Participants:

Mike Paul	Basin Electric Power Coop	Bismarck, ND	(701) 355-5691
Bill Siegfriedt	Sargent & Lundy	Chicago, IL	(312) 269-2015
John Toher	d/b/a IJM Consulting	Columbia, MD	(410) 910-5100

Subject: Consultant's View of Circulating Dry Scrubber

John Toher is a consultant formerly with Niro Atomizer, then Environmental Elements. He has been involved with several of the CDS projects to date and maintains his office at Lurgi Lentjes North America.

S&L inquired about stoichiometric ratio on low-sulfur fuels at high removal rates. Toher pointed out that as you push any dry technology to higher and higher removal efficiency, reagent consumption goes up. He pointed out that low-sulfur western fuels are ideal candidates for dry scrubbing, because even with poor reagent utilization, the reagent consumption is not too bad in terms of absolute quantities. Toher stated that 250 MW is still not "wet FGD territory." At 98% removal on PRB coal, he estimated stoichiometric ratio of 1.6 "or a little higher."

Toher pointed out that the Neil Simpson station occasionally has to go as high as 97% removal. The new permit for BHP will have a 3 hour average, which will force operations to tighten up a bit.

S&L asked for a review of the three CDS suppliers. Toher's response:

	Technical	Commercial
Lurgi	The LLNA organization is small. Toher is the guru. Harald Sauer has retired.	mg sold 80% of LLNA to Envirotherm, so mg's deep pockets are no longer available.
Babcock Power/ Austrian Energy	BPEI has good project organization. No expertise with this techn. in US. Some technology from Von Roll.	License.
Wulff	Dr. Graf knows what he's doing. Units in Germany and Poland Lots of work in China (one troubled).	Lacks a US partner. Toher willing to help.

John e-mailed his résumé.

Appendix C SCR Evaluation

High Dust vs. Low Dust SCR Application at Dry Fork Station

S&L PROJECT NO 11786-001

Revision	Date	Purpose	Prepared	Reviewed	Approved
0	4/22/05	For Client Comments	R. P. Gaikwad	W. A. Rosenquist	W. DePriest
1	5/27/05	Draft Final	R. P. Gaikwad	W. A. Rosenquist	W. DePriest
2	8/15/05	Final	R.P. Gaikwad	W.A. Rosenquist	W. DePriest
3	10/07/05	Final	R.P. Gaikwad	W.A. Rosenquist	W. DePriest
4	10/27/05	Final	R.P. Gaikwad	W.A. Rosenquist	W. DePriest

HIGH DUST vs. LOW DUST SCR APPLICATION at Dry Fork Station

1. INTRODUCTION

Typically a selective catalytic reduction (SCR) system for a coal fired power plant is located at the economizer outlet where the flue gas temperature is most suitable for the reaction between ammonia (NH_3) and nitrogen oxides (NOx). However, at this location the flue gas conditions can also have characteristics that are detrimental to the operation of the SCR and to the SCR catalyst. These flue gas characteristics can be especially troublesome with PRB coals where the ash chemistry is highly alkaline and contact with the catalyst can lead to a shorter catalyst life. In extreme cases where water or high humidity flue gas can enter the SCR reactor, severe catalyst damage could occur. Therefore, an alternate location downstream of flue gas desulfurization (FGD) and particulate collection systems where sulfur and ash are in low concentration is worthy of consideration. However, due to low flue gas temperature at the outlet of the FGD, it will be required to raise the flue gas to a temperature to 650˚F to facilitate the reaction between NH_3 and NOx. Typically, most SCR applications will utilize the high dust configuration due to lower capital, lower operating costs, and a growing confidence in the measures required to protect the performance of the SCR from deactivation and pluggage. Low dust configurations have been utilized on the existing units where there was inadequate space to retrofit a high dust SCR (which translates into a high capital cost) or where the fuel properties were such that the catalyst would be deactivated at faster rate in the high dust configuration due to either constituents in flue gas or in the ash. In general, a typical economic analysis will favor a high dust configuration. However, extenuating circumstances such as site constraints or available space and/or fuel properties, can sway the evaluation to favor a low dust configuration. Typical schematics for high dust and low dust SCRs are provided in Figures 1 and 2 respectively.

In high dust SCR system, flue gas from the economizer outlet, typically between 650˚F to 750˚F is directed to SCR reactor containing the catalyst. Ammonia is injected and mixed with the NOx before the mixture enters the SCR reactor. Ammonia reduces NOx to nitrogen and water. Under some design constraints, the reactor can be designed to be bypassed during startup and shut down.

In low dust SCR system, flue gas from ID fan outlet (typically at 165°F to 170°F for a dry FGD system) is directed to one side of a gas-gas heat exchanger (GGHE) to raise the gas temperature to approximately 600°, then through either an in-duct gas burner or steam heat exchanger to raise the temperature by 50F° and then to the SCR reactor at approximately 650°F. The ammonia is injected and mixed with the NOx before the mixture enters SCR reactor. Injected ammonia reduces NOx to nitrogen and water. The flue gas from the SCR outlet is then returned to the other side of the GGHE to recover the heat before the flue gas is sent to the stack. Due to the effectiveness limitations of the GGHE, the outlet temperature from the low-dust SCR system will be approximately 50°F to 60°F higher than the inlet temperature resulting in a stack temperature of approximately 220°F or about 50F° higher that the stack gas from the high dust configuration.

The purpose of this paper is to identify the technical and economic differences between high dust and low dust SCRs for an application at Basin Electric's proposed new power plant. A list of SCRs installed on PRB coals with high dust SCR in the U.S.A. is attached in Appendix A. At present, there is only one low dust SCR installation in the U.S.A. at Mercer Station. The low dust SCR at Mercer is operated after a cold side ESP and the flue gas is heated with natural gas. The Mercer SCR does not respond well with the load variation primarily due to operation of the twin boiler design.

2. TECHICAL DIFFERENCES BETWEEN HIGH AND LOW DUST SCRS

The differences between high and low dust SCRs can be characterized with the following parameters.

- NOx Removal Efficiency
- SO_2 Oxidation
- Type of Catalyst
- Catalyst life

- Pressure Drop
- Ammonia Slip Impact
- Supplemental Heat Requirement
- SCR Bypass

2.1 NOx Removal Efficiency:

Based on pulverized coal (PC) boiler technology application at Dry Fork Station generating station, the inlet NOx to SCR is estimated to be 0.20 lb/MBtu. Considering an inlet of 0.2 lb/mmBtu and experience in the industry on PRB coals, the lowest recorded NO_X outlet from a high dust SCR will be approximately 0.03 lb/mmBtu. However, considering the more uniform NO_X distribution in the flue gas at the inlet of a low dust SCR, a longer distance available for ammonia to NOx mixing prior to the catalyst, and the experience associated with dust free environment in SCRs on combined cycle units, a lower emission rate may be achievable with a low dust SCR. Both SCRs system would meet the current BACT limit of 0.07 lb/MBtu.

2.2 SO_2 Oxidation:

The SCR catalyst contains vanadium pentoxide (V_2O_5) as an active ingredient, which will convert a portion of the SO_2 in the flue gas to SO_3. Due to the effect that SO_3 in its condensed form as sulfuric acid, will have on opacity (in some cases referred to as "blue" plume), the SCR is designed with a low level of SO_2 to SO_3 oxidation. However, considering the low sulfur PRB coal and the installation of dry FGD w/FF for SO_2 control, (which will remove greater than 95% of SO_3 from the flue gas), the high dust SCR can be designed for a relatively high oxidation rate of 2-3% without any significant impact on condensables or plume opacity. For example, a typical PRB fired unit operating with 0.6 lb/MBtu SO_2 at the SCR inlet will contain approximately 310 ppmvd SO_2 (@3% O_2) in the flue gas. A 2% conversion of this SO_2 to SO_3 will result in 6.2 ppmvd SO_3 (@3% O_2).

95% of this SO_3 will be removed in dry FGD/FF resulting in an outlet concentration of only 0.31 ppmvd SO_3 (@3% O_2), which will not impact opacity.

For low dust application, the SCR is downstream of dry FGD, and therefore the SO_2 concentration at the inlet of SCR will be extremely low. For example, if the unit is operating with 0.06 lb/MBtu SO_2 at the low dust SCR inlet (approximately 31 ppmvd SO_2), then even a 2% conversion of this SO_2 to SO_3 will result in only 0.62 ppmvd SO_3 (@3% O_2) in the stack which will not impact opacity.

In summary, an SO_3 content of over 5 ppm is required in the flue gas before it will have an effect on plume visibility. Therefore, there is no real difference between a high dust and a low dust SCR relative to the concern of SO_2 oxidation and plume visibility.

2.3 Type of Catalyst:

The catalyst chosen for high dust vs. low dust application will have different catalyst pitch. Due to dust loading and properties of PRB ashes (sticky ash), 8.4 mm or larger pitch is required for high dust application. However, for low dust application, the catalyst pitch could be approximately 5 mm. The lower pitch will provide large surface area for the catalyst per unit volume of catalyst. Based on these requirements for PRB coal, and assuming the same NO_X reduction requirements, it is estimated that the catalyst for low dust will be approximately 0.4 times the amount required for high dust application. This is partially offset because the catalyst for high dust is estimated to be approximately $5,000 per cubic meter vs. $6,000 per cubic meter for low dust application. The lower volume of catalyst for a low dust configuration results in a smaller SCR reactor with the attendant capital savings.

2.4 Catalyst Life:

Because of the inherent deactivation rates of catalyst in high dust and low dust environments, the initial catalyst and SCR reactor is typically sized for 2 years of life for high dust application and for 3 years of life for low dust application. Room for an additional layer of catalyst in the reactor is used for catalyst management. It is estimated that over the 42 year evaluation period for this project, approximately 16 layers of replacement catalyst (average 1 layer every 2.5 years) will be required for high dust configuration whereas only 7 layers of replacement catalyst (average 1 layer every 6 years) will be required for low dust configuration application.

2.5 Pressure drop:

The pressure drop across the high dust SCR configuration includes the pressure drop across the inlet duct, static mixers, ammonia injection grid, flow straightener, catalyst, and SCR outlet duct. The pressure drop across the catalyst is typically designed for approximately 3.0" w.c. and the rest of the system will have approximately 3" w.c. for a total of 6" w.c.

The pressure drop across the low dust SCR configuration includes the pressure drop across the duct, GGHE (dirty side), steam flue gas heater, static mixers, ammonia injection grid, flow straightener, catalyst, SCR outlet, and GGHE (clean side). The pressure drop across the SCR system therefore includes approximately 2.5" w.c. across the SCR catalyst, 3.0" w.c. across the static mixer and other devices, 3.5" across dirty side of GGHE, 3.5" across the steam heater, and 3.5" w.c. across clean side of GGHE for a total of 16.0" w.c.

For the comparison purposes, the low dust configuration will have 2.7 times the pressure drop of the high dust configuration and therefore a significantly higher fan power requirement.

2.6 Ammonia Slip Impact:

SCRs are typically designed for 2 ppmvd (@3% O_2) ammonia slip to avoid reaction with SO_3 in the flue gas to form ammonia bi-sulfate and to prevent contamination of the fly ash with ammonia. The design NH3 slip can be higher for PRB coal as there is very little SO_3 in the flue gas and only 10% to 20% of ammonia is adsorbed on the alkaline ash. However, there could be NH_3 emission permit limitations due to the potential for formation of fine particulates in the atmosphere, which may impact visibility modeling. Somewhat higher ammonia slip can be tolerated with the high dust configuration because the dry FGD/FF will adsorb some NH_3 on the waste material in the baghouse. Ammonia slip should be less than 1 ppmvd (@3% O_2) in the stack with a high dust configuration followed by a dry FGD system. Most of ammonia will be compounded with SO_3 to form ammonium sulfate/bisulfate. More than 95% of the sulfated products should be removed in the baghouse resulting in very small amount of sulfate emission from the high dust SCR system. For a low dust SCR configuration, all of the ammonia slip will be emitted from the stack. The low dust SCR configuration will therefore have higher ammonia emission than the high dust configuration. The ammonia emission with the low dust application will be affected by very low amount of SO_3 in the flue gas. The low SO_3 concentration in the outlet will result in ammonium sulfate formation. As the SO_2 emissions fall below 0.10 lb/MBtu, there is a very good possibility that gaseous ammonia may be emitted from the stack. This translates into a slight advantage to the high dust configuration but only if the NH_3 emissions become a constraint in the permitting process.

2.7 Heat Requirement:

The high dust SCR will not require any additional heat as the new boiler design will accommodate optimum operating temperature for the SCR at the economizer outlet. Conversely, the low dust SCR will be installed after dry FGD system. The temperature from FGD/FF system will be approximately 170°F. However, the SCR catalyst designed for a low dust application will have optimum effectiveness in a temperature range between 620°F to 650°F. To achieve this temperature in the SCR reactor the gas from dry FGD/FF outlet is heated by first using a GGHE to recover the heat from the gas leaving the SCR and then by heating the gas further either by in-duct gas burner or in-duct steam heater. Due to low fuel cost at Dry Fork Station station, steam heating was chosen in this analysis as the low cost solution. The heating of the flue gas from 600°F to 650°F will require high temperature steam. To accommodate this requirement, the boiler will have to be designed to supply the quality of the steam required for this application. The estimated net heat requirement for this low dust configuration is approximately 61 MBtu/hr. This is a significant energy penalty on the low dust configuration. However, the low cost fuel and the opportunity to configure the steam cycle in an optimum fashion will help to minimize this impact.

2.8 SCR Bypass:

The high dust application of SCR on a boiler fired with PRB coal will probably require an SCR bypass to protect the catalyst during the start up and shut down as well as during boiler upset conditions primarily to avoid subjecting the catalyst to the water dew point. Conversely, since the low dust SCR configuration is not subjected to the PRB fly ash at high concentration, it will not require SCR bypass during start up and shut down. In general, the low dust configuration places the SCR catalyst in a much less vulnerable location considering the potential harm that can come from exposure to the alkaline ash from PRB coal during start up and shut down.

3. ECONOMIC ANALYSIS

The economic comparison of high dust and low dust SCR, the study assumptions are summarized in Table 1:

Table 1: Study Assumptions

	High Dust	Low Dust
1. Fuel to be fired	Dry Fork	Dry Fork
2. Heat Input, MBtu/hr[1]	3801	3801
3. SCR Design Temperature[2], °F	700	620
4. Inlet NOx, lb/MBtu	0.20	0.20
5. Required Efficiency, %	85	85
6. Catalyst Pitch, mm	8.4	5.0
7. Initial Catalyst Life, yrs	2.0	3.0
8. SO_2 to SO_3 Oxidation, %	2.0	2.0
9. GGHE Required	No	Yes
10. In-duct Heating Required[3]	No	Yes
11. SCR Bypass Required[4]	Yes	No
12. SCR System Pressure Drop[5], "w.c.	6.0	16.0
13. Power Consumption[6], kW	1,608	4,109
14. Power Cost, $/kWh	29.6	29.6
15. Temp. Rise Across Steam Heater[7], °F	0	50
16. Heat Requirement, MBtu/hr	0	61
17. Steam Cost[8], $/MBtu	0.37	0.37
18. Catalyst Cost, $/m^3	5,000	6,000
19. Amount of catalyst required, m^3	576	230
20. Catalyst Replacements in 42 yrs[9]	16	7
21. Type of Ammonia Used	Anhydrous	Anhydrous
22. Ammonia Cost, $/ton	425	425

Notes:

1. Heat Input - Based on an annual average
2. Typical SCR design temperature
3. Superheated steam is used for heating the flue gas. The lower temperature steam is returned back to the steam cycle.
4. SCR bypass for high dust application is required to protect the catalyst during start up and shut down
5. Explanation is provided in pressure drop write-up in Section 2.5
6. Power consumption includes all electrical power requirements
7. Estimated based on the similar application
8. Steam cost is assumed to be same as coal cost, 0.37 $/MBtu
9. Explanation is provided in catalyst life write-up in Section 2.4

Capital Cost:

The capital costs were developed based on S&L's recent experience on PRB coal projects and previous studies for new power plants. Capital cost for the high-dust SCR represents costs for a complete SCR system including the costs of SCR reactor and associated dust work with mixers and distribution devices, initial catalyst and by-pass dampers, foundations, steel pro-rata auxiliary power system and all necessary appurtenances.

The capital costs for the low-dust SCR also represents a complete SCR system including the SCR reactor, duct work, initial catalyst, gas-to-gas heat exchanger, steam flue gas heater, associated steam piping foundations, steel, pro-rata components of the ID fans and auxiliary power systems, and all necessary appurtenances.

O&M Costs:

The O&M costs include both fixed and variable operating costs that are defined as follows:

Fixed O&M Costs:

The fixed O&M costs consist of operating and maintenance labor, maintenance material, and administrative labor. For purposes of this analysis, the installation of SCR has not been anticipated to add to the labor pool of operating labor at the new unit.

The material handling activities associated with the unloading and transfer of ammonia represent an incremental amount of the plant material handling activities, but should be a fraction of a full-time person, so it is believed the plant staff can accommodate the additional work. Maintenance material and labor costs shown herein have been estimated based on operating experience in the U.S and Europe and includes the maintenance of the ammonia delivery/storage/handling system, dilution air fan, dampers, GGHE, steam pipeline, and tuning of ammonia injection grid. The details of fixed O&M costs are given in Appendix B.

Variable Operation and Maintenance Costs:

The variable O&M costs for the SCRs include the cost of ammonia, catalyst replacement including labor, steam requirement, and power requirements. The economic basis for operating cost is given in Table 1 and the details are given in Appendix B.

No added penalty for lost production has been included due to forced downtime to maintain the SCR system because the availability (measure of random outage rates) of these systems is expected to be greater than 99% with no significant difference between the high dust and low dust configurations. Auxiliary power costs reflect the additional power requirements associated with operation of the ID fans to overcome the gas side pressure drop as well as the estimated power consumption for ancillary equipment.

Present Value Analysis

A present value analysis was performed based on the capital and O&M costs, and the following parameters which were used in the previous BEPC study:

- Debt amortization period = 30 years
- Project evaluation period = 42 years
- O & M escalation = 2%
- Discount Rate = 6%/year

The net present value for these two alternatives is shown on the chart below:

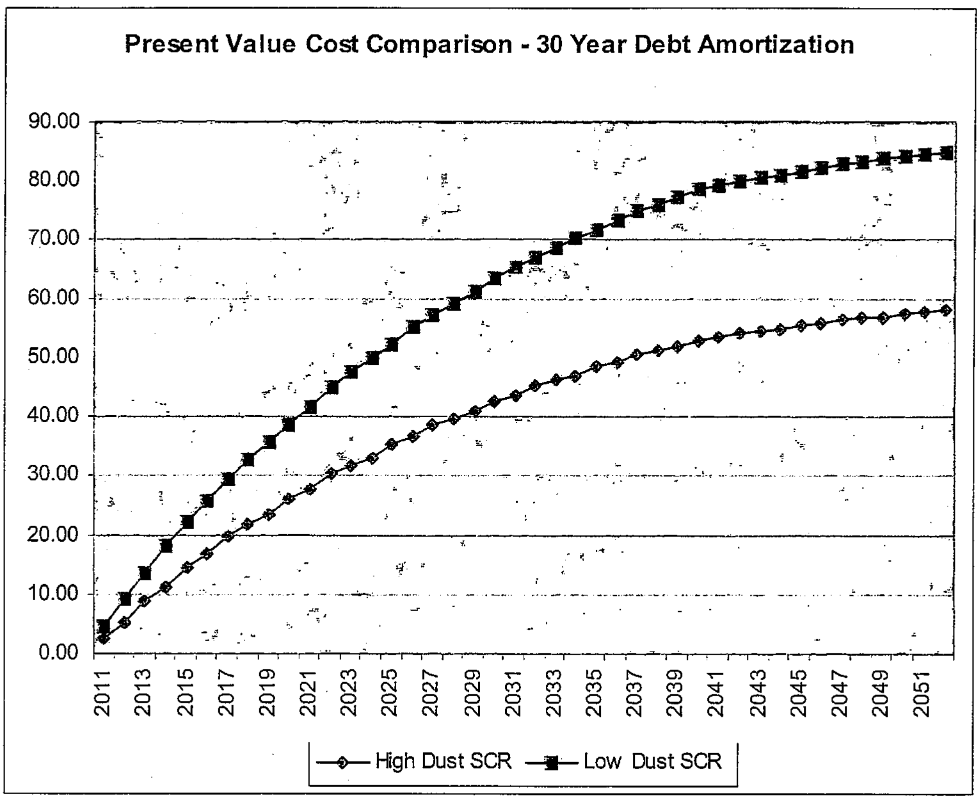


Chart 1 – Net Present Value Comparison

Summary

Capital, O&M, and net present value is summarized below:

	High Dust	Low Dust
Capital ($1,000,000)	19.9	35.2
O & M without catalyst ($1,000,000)	1.01	1.85
Number of Catalyst replacements	16	7
Net Present Value – Capital ($1,000,000)	22.41	39.75
Net Present Value – O&M ($1,000,000)	23.24	42.50
Net Present Value – Catalyst ($1,000,000)	12.43	2.95
Net Present Value (42 years) - Total	58.08	85.2
Approximate NPV difference ($1,000,000)	Base	27.12
NPV/Year ($1,000,000)	Base	0.646

Sensitivity Analysis

Information provided by STEAG based on their experience with low dust SCRs in Europe indicates that the present estimate of catalyst life and pressure drop may be somewhat conservative. To understand the significance of these issues a sensitivity analysis was performed using a lower pressure drop of 10" w.c. and a longer catalyst life:5 changes in 42 years as opposed to the 7 originally planned.

Catalyst life: The catalyst used in Germany in 1980s is substantially larger than what a catalyst supplier would provide today in the USA. This size increase result in a longer catalyst life for SCRs typically designed to achieve 70% NOx reduction efficiency with 2-5 ppmvd ammonia slip. If the catalyst life is extended as described by STEAG, then only 5 replacements will be required over the life of the unit. This is two less replacements than in the original estimate.. This results in a cost differential between high and low dust shrinks to 26.1 M$ in lieu of 27.1 M$ indicating the catalyst life for low dust is not a significant contributor towards NPV of the project.

Pressure: The pressure drop shown during STEAG's presentation was approximately 10"w.c. which is substantially lower than 16" calculated by S&L. The 16" used by S&L is based on the guaranteed operating condition from a recent low dust SCR project, which operates at approximately 15" w.c. The additional 1" w/c. is intended to accommodate some fouling of the system components. It should be noted that the pressure drop is the function of velocity through the equipment. S&L does not have any data from STEAG showing what the velocities were in the various part of the system. It is indeed possible the original equipment was sized conservatively. A drop of 20-25% in velocity could result in 40-50% lower pressure drop. However, the initial capital cost would then be higher. A sensitivity analysis of reducing pressure drop from 16" w.c. to 10" w.c shows that the cost differential between high and low dust changes to 19.7 M$ from 27.1 M$. Therefore, the pressure drop is a significant contributor towards NPV of the project. If a low dust SCR is selected then high consideration must be given to the trade off between capital cost and pressure drop through the system.

Combined pressure drop and catalyst life: The combination of both reductions result in a difference between high and low dust NPV of 18.7 M$ which is still more than 32% higher than high dust SCR NPV.

4.0 CONCLUSIONS

Both alternatives are technically feasible. The advantages and disadvantages are discussed below:

High-Dust SCRs

- Overall lower capital and life cycle costs
- Commercially, the boiler vendor will supply a high dust SCR with the boiler package
- Operates in high dust flue gas environment making the catalyst more susceptible to upsets in plant operating conditions, such as: economizer tube leaks, ash pluggage, and changes in fuel properties.
- Operating SCRs on PRB in the high dust configuration have demonstrated a higher rate ~~of deactivation compared to application on bituminous coals. However, this higher~~

deactivation rate has not been a "fatal flaw" in the use of high dust SCRs in PRB application.

Low-Dust SCRs

- Eliminates any need for an economizer flue gas by-pass
- Less susceptible to upsets in plant operating conditions, such as; economizer tube leaks, ash pluggage, and changes in fuel properties
- Results in more stable NO_x control during start up and normal operation of the NO_x levels because it is impacted less by boiler outlet variations. This is especially important with a 24-hour average.
- Allows catalyst to operate in clean environment, which results in lower exposure to PRB ash and a longer catalyst life
- Less susceptible to changes in fuel properties, due to the location after the dry FGD and baghouse.
- Smaller volume of catalyst
- Low dust environment allows for use of smaller pitch catalyst
- Low SO_2 concentration allows for a high catalyst activity and therefore, a smaller amount of catalyst
- Higher capital and operating costs due primarily to the gas-to-gas heat exchanger, the steam flue gas heater, and more complicated ductwork
- Commercially, the boiler vendor may not want to supply the low dust SCR unless they supplied the boiler, dry-FGD, baghouse and low-dust SCR
- Alternately, the SCR could be designed and procured as a stand-alone package, such as is currently being done on SCR retrofit projects
- Design of the flue gas reheater requires a source of heat off the cycle (either steam or water) thereby reducing the power generated from the steam turbine.
- Due to higher heat rate of the low dust configuration compared to high dust SCR configuration, the emissions of SO_2, PM, etc. per MWH will be higher for low dust SCR.

- Ammonia based emissions will be higher for low dust SCR than high dust SCR due to proximity of low dust SCR being downstream of the FGD and FF.

5. RECOMMENDATION:

Considering NOx reduction capabilities, operational flexibility, secondary emissions, overall plant efficiency and economics of the low and high dust configurations, Sargent & Lundy LLC recommends that the Dry Fork Station project employ the high dust SCR configuration.

Sargent & Lundy acknowledges that the low dust configuration will potentially offer a slightly higher NOx reduction efficiency, and therefore a slightly lower NOx emission rate on an equal heat input basis. However, this minor advantage in NOx emissions rate on a lb/MMBtu heat input basis is overshadowed by the fact that the higher heat rate of the low dust configuration will result in a higher emission rate for the other criteria pollutants (SO_2, PM, etc.) and CO_2 on a plant output basis (lbs/MWh). For these reasons, selection of the low dust configuration is not warranted.

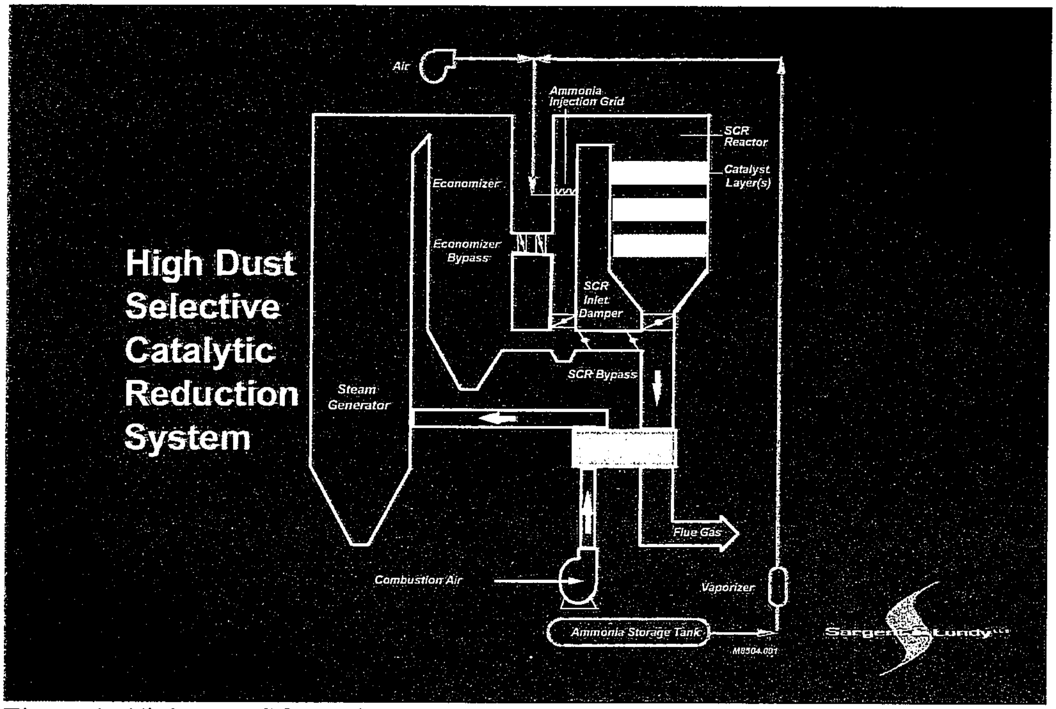


Figure 1: High Dust SCR Schematic

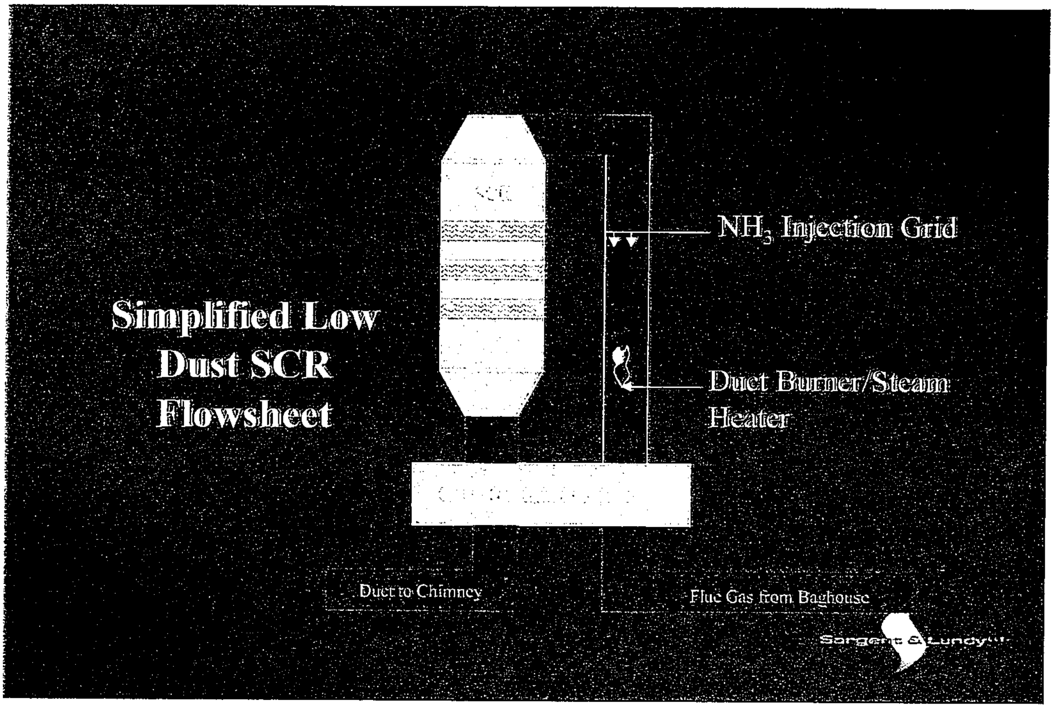


Figure 2: Low Dust SCR Schematic

Appendix D Cost Estimates

CH2M HILL
PC Alternative with Air Cooled Condenser

CLIENT:	Basin Electric Power Cooperative	ESTIMATOR:	R. J. Witherell
PROJECT:	280 MW Subcritical PC Power Plant	DATE:	11/03/2004
LOCATION:	Gillette, Wyoming	REVISION:	5
Job No.:	317334	CASE:	

1.0 PURPOSE

To prepare a Cost Estimate for engineering, procurement and construction (EPC) services for a 280 MW (gross) subcritical Pulverized Coal (PC) fired power plant for Basin Electric Power Cooperative. The American Association of Cost Engineers (AACE) has developed definitions for levels of accuracy commonly used by professional cost estimators. The AACE defines the cost estimate as set forth here, based on preliminary flow sheets, layouts, equipment quantities and type as a Budgetary estimate. An estimate of this type is expected to be accurate within plus 30 percent to minus 15 percent of the estimated cost. However, due to the high percentage of quoted equipment including installation quotes for the Boiler, Air Quality Control Systems, Air Cooled Condenser, and Coal Handling System, it is felt that the accuracy range is better defined as plus 20 minus 15 percent.

2.0 SCOPE

The facility will be a subcritical Pulverized Coal Fired power plant with one (1) PC fired Steam Generator and one (1) 280 MW single reheat two-flow exhaust Steam Turbine Generator (STG). The plant will be a mine-mouth unit with area allocated on the site for a future rail loop, rail coal delivery and unloading system. The facility generally consists of the following:

Steam Generator and accessories
SCR and Ammonia System
Baghouse
Dry FGD System
Lime Storage
STG and Hydrogen Cooling System
Air-Cooled Condenser
Feedwater System
Condensate System
Coal Handling System
Ash Handling System
Plant Air System
Blowdown System
Main Steam and Reheat System
Steam Seals System
Water Treatment System
Firewater System
Chemical Feed System
Electrical Equipment & Bulks including 230 kV Switchyard
ZLD System
CEMS
DCS
Auxiliary Boiler
Instrumentation Bulks
~~Civil & Structural Works including Ponds~~
Site Buildings and Structures including Warehousing and Offices

3.0 CONSTRUCTION APPROACH

The estimate is based on a direct-hire open-shop craft labor (mix of Union and Non-union craft) with multiple EPC contractors for the following:

- Steam Generator and Air Quality Control System (AQCS) including Baghouse, Dry Scrubber (FGD) and SCR (furnish and install basis)
- Balance of Plant (furnish and install basis) includes all BOP Equipment, Tanks S/C, Bulks, Sitework, Engineering, construction and startup
- Chimney Contractor
- Coal Handling Contractor
- Air Cooled Condenser Contractor
- Coal Storage Silos
- ZLD Contractor
- Switchyard

4.0 QUANTITY BASIS

Quantities for bulks were determined based on values contained in the CH2M HILL coal plant estimating model database which has been developed based on historical data derived from similar recently completed and proposed projects in terms of size and configuration. Historical data was utilized to provide an overall parametric check of account values of the completed estimate.

4.1 Earthwork Account: Earthwork was based on a take-off from General Arrangements to determine cut and fill quantities. Paving, gravel, underground/aboveground utilities, ponds, site drainage and fencing quantities were derived from the General Arrangement Site Plan.

4.2 Concrete Account: Concrete quantities were based on values contained in the CH2M HILL coal plant estimating database and are quantified based on pour type, plant area and equipment type.

4.3 Steel Account: Quantities for building structures, piperack and miscellaneous steel were based on values contained in the CH2M HILL coal plant estimating database and are broken out in terms of light, medium , heavy, extra heavy steel and well as a breakdown for grating, ladders, stairs, handrail, kickplate, etc.

4.4 Equipment quantities and capacities were determined based on a detailed equipment list developed from preliminary P & IDs and are described in detail in terms of equipment quantities and capacities.

4.5 Large bore, major small bore and underground pipe quantities were based on quantities contained in the CH2M HILL coal plant estimating database and broken out into large bore, small bore, underground piping.

4.6 An Electrical Equipment list with quantities and capacities was utilized to establish the estimate for the electrical account. Bulk quantities for wire, terminations, conduit, tray, grounding and electrical heat tracing were determined based on values contained in the CH2M HILL coal plant estimating model database.

4.7 An Instrument Equipment list with quantities including CEMS and DCS was utilized to establish the equipment list for the estimate. Quantities for instruments and bulks were determined based on values contained in the CH2M HILL coal plant estimating model database.

4.8 Painting and Insulation quantities were derived from estimated quantities from the steel, equipment and piping accounts.

4.9 Buildings and Architectural – Based on quantities derived from General Arrangement Layouts and was broken out to include exterior and interior elements including doors, windows, siding, roofing, floors and wall finishes.

5.0 PRICING BASIS

5.1 Earthwork Account: Based on man-hour rates and costs experienced on other recently complete projects and on in-house estimating database information for manhours and bulk pricing.

5.2 Concrete Account: Manhours, formwork, reinforcing steel, finishing and grout based on in-house estimating database information. We have adjusted the ready-mix concrete price per cubic yard to $85.00 based on telephone quotes from local suppliers. Pricing for reinforcement material was adjusted to $.45 per pound to reflect recent price increases for this material.

5.2 Steel Account: Steel man-hour installation rates, piperack and miscellaneous steel, grating, handrail, checkered plate, ladders, stair treads and stringer were all based on costs experienced on other recently completed projects and on in-house estimating database information. The cost for steel has been adjusted to reflect the latest pricing being experienced for this material based on current quotes.

5.3 Equipment Account: Quotes were based on brief performance specifications in the form of one or two page data sheets prepared for each of the major equipment items. All quotes were stated in current dollars.

5.3.1 Steam Generator – (1) Each: Quotes received from B & W, Foster Wheeler & Alstom. Prices are quoted in present-day dollars. B & W pricing was used as the basis for this estimate and the scope includes the steam generator, baghouse, SCR and dry FGD system.

5.3.2 Steam Turbine Generator – (1) each: 280 MW single reheat unit with two-flow exhaust: Equipment quotes were received from Alstom, Siemens, and GE. Siemens pricing was used as a basis for this estimate.

5.3.3 Air-Cooled Condenser - Pricing based budgetary written equipment quotes received from GEA and Marley . Marley was used as a basis for this estimate.

5.3.4 Coal Handling and Ash Handling Systems – A budgetary quote FMC was received and was used as a basis for the in-battery limits Coal Handling System costs. The FMC quote included equipment, erection, dust suppression, and sampling system costs. A budgetary quote from United Conveyor was used as a basis for the Ash Handling System cost and included costs for equipment.

5.3.5 Stack and Breeching – Pricing based budgetary written equipment quotes received from Hamon Custodis, Hoffman, and Gibraltar Chimney for the 500 foot Stack and Breeching. Hamon Custodis pricing was used.

5.3.6 Coal Storage Silos – Pricing was received from Hoffman for the Coal Storage silos.

The balance of equipment and installation rates were based on man-hour rates and costs experienced on other recently completed projects and on in-house estimating database information.

5.4 Piping Account: Pricing for pipe, fittings and shop fabrication was based on recently received pricing from Team Industries, Bendtec and International Piping. Pricing for Valves and Specialties and installation rates were based on recently completed projects and on in-house estimating data.

5.5 Electrical Account: The electrical equipment, installation man-hours, pricing for wire, terminations, conduit, tray, grounding and electrical heat tracing was based on man-hour rates, quotes received and costs experienced on other recently completed projects and on in-house database information.

5.6 Instrumentation Account: The instrumentation, DCS, CEMS and installation man-hours, and pricing for bulks was based on man-hour rates and costs experienced on other recently completed projects and on in-house database information.

5.7 Site Building Account: Unit prices based on recent project pricing and on database information for siding, roofing, building mechanical and electrical components and architectural elements.

6.0 LABOR

Open-shop craft labor rates were derived from published prevailing (union and non-union mix) wages for the area. A labor factor of 1.11 was assumed based on review of various factors including location, congestion, local labor conditions, weather and schedule. A fifty hour work week was assumed to attract craft with incidental overtime as required. A per diem of $40.00 was included.

7.0 SCHEDULE

Start Engineering:	May 2006
Start Construction:	May 2007
Mechanical Completion:	October 2010
COD	January 2011

Assumed was detailed engineering duration approximately 30 months (including procurement); construction duration 42 months with 9 months start-up. The total duration was assumed to be 57 months.

8.0 HOME OFFICE ENGINEERING SERVICES

Detailed engineering was calculated using wage rates by salary category including work by disciplines estimating the engineering production and support work-hours based on type and sequence for the work required. Additional expenses were added for reproduction, computers, outside services and travel. These engineering services apply to the BOP contractor only.

9.0 CONSTRUCTION INDIRECTS

Includes costs for Field Staff, Temporary Facilities, Construction Equipment and small tools/consumables, Heavy Hauling, Start-up Craft Assistance and temporary start-up supplies, spare parts and consumables.

10.0 CONTRACTOR'S CONTINGENCY

A contingency was included of 8% based on an assessment of major cost elements.

11.0 CONTRACTOR'S FEE

An 10% fee (including G & A) was applied based on all cost elements related to the BOP contract.

12.0 INCLUSIONS

Structural and civil works to the site battery limits
Piling
Mechanical and plant equipment
Bulks
Contractor's construction supervision
Temporary facilities
Construction power and water
Construction equipment, small tools and consumables
Start-up spare parts and start-up craft labor
Interest During Construction @ 6.5% lend rate.
230 kV Switchyard
Sales Tax @ 5.00%.
First fills
Contractor's Contingency and Fee
Insurances (Workers' Comp, Liability and Builders Risk)
Performance and Payment Bond Cost @ $.04/$1,000.

13.0 EXCLUSIONS

Demolition, soils remediation, moving of underground appurtenances or piping (unless noted otherwise), excavation at site location to depth required to reach undisturbed soil..
Delay in start-up insurance.
Plant Licenses or environmental permits.
Removal or relocation of existing facilities or structures (unless noted otherwise)
Dewatering except for runoff during construction.
No on-site fuel oil storage is included.
Risk assessment for determining probability of overrun or underrun is not included.

14.0 ASSUMPTIONS & QUALIFICATIONS

All excavated soil will be disposed of elsewhere on the site
This site does not contain any EPA defined hazardous or toxic wastes or any archaeological finds that would interrupt or delay the project.
Equipment is supplied with manufacturers standard paint
Craft parking is immediately adjacent to site
Craft bussing is not required.
Rock excavation is not required.
A construction or operating camp has not been included.
An ample supply of skilled craft is available within the vicinity of the site.
Startup fuel is natural gas.
The site has free and clear access with adequate laydown area immediately adjacent to the site.

15.0 INTERCONNECTS

ROADS:	Tie in to existing road at Battery Limit
WATER:	Well Field
ELECTRIC:	Battery Limit
VOLTAGE:	230 kV

16.0 SWITCHYARD

230 kV

17.0 SALES TAX

Tax rate is 5.00%.

CH2MHILL

Client: Basin Electric Power Cooperative
Project: PC Subcritical 280MW (gross) Plant
Location: Gillette, Wyoming
Job No.: 317334
Case:

Date: November 3, 2004
Estimator: R.J. Witherell
Rev. No.: 8

Account No.	Description	Quantity	Unit	MH/ Unit	MH Rate	Material Unit		Manhours	LABOR	MATERIAL	SPECIALTY SUBCONTRACTS	TOTAL	Size	Remarks
	EARTHWORK				$30.94			34,482	$1,066,882	$436,315	$10,510,857	$12,014,053		
	CONCRETE			7.24	$33.21	$199.63		198,102	$6,578,974	$5,459,627		$12,038,602	27,349 CY	
	STEEL			23.68	$31.18	$2,605.00		79,073	$2,465,487	$6,847,384		$9,312,871	2,629 TN	
	EQUIPMENT				$43.02			147,785	$6,357,723	$129,881,066	$103,720,213	$239,959,003		
	PIPING			2.40	$37.79	$79.90		259,984	$9,824,790	$8,662,526	$2,300,000	$20,787,316	108,423 LF	
	ELECTRICAL				$38.84			318,283	$12,362,116	$18,668,107		$31,030,222		
	INSTRUMENTATION & CONTROLS				$38.84			26,045	$1,011,604	$6,243,971		$7,255,575		
	PAINTING										$1,535,410	$1,535,410		
	INSULATION										$5,080,284	$5,080,284		
	BUILDINGS & ARCHITECTURAL										$6,780,551	$6,780,551		
	DIRECT FIELD COST				$37.29			1,063,755	$39,667,576	$176,198,996	$129,927,314	$345,793,886		
	FIELD STAFF & LEGALITIES											$14,130,097		
	TEMPORARY FACILITIES											$6,012,068		
	CONSTRUCTION CAMP													
	CONSTRUCTION EQUIPMENT, TOOLS, SUPPLIES											$9,940,888		
	START-UP TESTING AND TRAINING							26,334	$3,151,184	$150,000	$750,000	$4,051,184		
	INDIRECT FIELD COST							26,334	$3,151,184	$150,000	$750,000	$34,134,237		
	TOTAL FIELD COST											$379,928,122		
	EPC (Balance Of Plant) ENGINEERING						$96.39	147,147				$14,184,126		
	SUBTOTAL FIELD AND ENGINEERING											$394,112,248		
	FREIGHT											Included		
	SUBTOTAL											$394,112,248		
	CONTINGENCY						8.00%					$31,528,980		
	EPC (Balance Of Plant) CONTRACTOR'S FEE						10.00%					$20,869,323		
	SUBTOTAL											$446,510,551		
	SWITCHYARD											$4,630,607		
	TAXES						5.00%					$12,843,573	CAMPBELL COUNTY, WY	
	INSURANCES (Workers' Comp, Liability and Builders Risk)											$18,200,000	PER BEPC	
	PERMITS											$50,000	ALLOWANCE	
	PERFORMANCE BONDS						$.04/1000					$17,860	PER BEPC	
	TOTAL											$482,252,591		

DEQ/AQD 001955

CH2M HILL
CFB Alternative with Air Cooled Condenser

CLIENT:	Basin Electric Power Cooperative	ESTIMATOR:	R. J. Witherell
PROJECT:	280 MW CFB Power Plant	DATE:	11/03/2004
LOCATION:	Gillette, Wyoming	REVISION:	4
Job No.:	317334	CASE:	

1.0 PURPOSE

To prepare a Cost Estimate for engineering, procurement and construction (EPC) services for a 280 MW (gross) Circulating Fluidized Bed (CFB) coal fired power plant for Basin Electric Power Cooperative. The American Association of Cost Engineers (AACE) has developed definitions for levels of accuracy commonly used by professional cost estimators. The AACE defines the cost estimate as set forth here, based on preliminary flow sheets, layouts, equipment quantities and type as a Budgetary estimate. An estimate of this type is expected to be accurate within plus 30 percent to minus 15 percent of the estimated cost. However, due to the high percentage of quoted equipment including installation quotes for the Boiler, Air Quality Control Systems, Air Cooled Condenser, and Coal Handling System, it is felt that the accuracy range is better defined as plus 20 minus 15 percent.

2.0 SCOPE

The facility will be a Circulating Fluidized Bed (CFB) Coal Fired power plant with one (1) CFB Steam Generator and one (1) 280 MW single reheat two-flow exhaust Steam Turbine Generator (STG). The plant will be a mine-mouth unit with area allocated on the site for a future rail loop, rail coal delivery and unloading system. The facility generally consists of the following:

Steam Generator and accessories
Baghouse
Dry FGD System
Limestone Storage
STG and Hydrogen Cooling System
Air-Cooled Condenser
Feedwater System
Condensate System
Coal Handling System
Ash Handling System
Plant Air System
Blowdown System
Main Steam and Reheat System
Steam Seals System
Water Treatment System
Firewater System
Chemical Feed System
Electrical Equipment & Bulks including 230 kV Switchyard
ZLD System
CEMS
DCS
Auxiliary Boiler
Instrumentation Bulks
Civil & Structural Works including Ponds
~~Site Buildings and Structures including Warehousing and Offices~~

3.0 CONSTRUCTION APPROACH

The estimate is based on a direct-hire open-shop craft labor (mix of Union and Non-union craft) with multiple EPC contractors for the following:

- Steam Generator and Air Quality Control System (AQCS) including SCR (furnish and install basis)
- Balance of Plant (furnish and install basis) includes all BOP Equipment, Tanks S/C, Bulks, Sitework, Engineering, construction and startup
- Chimney Contractor
- Coal Handling Contractor
- Air Cooled Condenser Contractor
- Coal Storage Silos
- ZLD Contractor
- Switchyard

4.0 QUANTITY BASIS

Quantities for bulks were determined based on values contained in the CH2M HILL coal plant estimating model database which has been developed based on historical data derived from similar recently completed and proposed projects in terms of size and configuration. Historical data was utilized to provide an overall parametric check of account values of the completed estimate.

4.1 Earthwork Account: Earthwork was based on a take-off from General Arrangements to determine cut and fill quantities. Paving, gravel, underground/aboveground utilities, ponds, site drainage and fencing quantities were derived from the General Arrangement Site Plan.

4.2 Concrete Account: Concrete quantities were based on values contained in the CH2M HILL coal plant estimating database and are quantified based on pour type, plant area and equipment type.

4.3 Steel Account: Quantities for building structures, piperack and miscellaneous steel were based on values contained in the CH2M HILL coal plant estimating database and are broken out in terms of light, medium , heavy, extra heavy steel and well as a breakdown for grating, ladders, stairs, handrail, kickplate, etc.

4.4 Equipment quantities and capacities were determined based on a detailed equipment list developed from preliminary P & IDs and are described in detail in terms of equipment quantities and capacities.

4.5 Large bore, major small bore and underground pipe quantities were based on quantities contained in the CH2M HILL coal plant estimating database and broken out into large bore, small bore, underground piping.

4.6 An Electrical Equipment list with quantities and capacities was utilized to establish the estimate for the electrical account. Bulk quantities for wire, terminations, conduit, tray, grounding and electrical heat tracing were determined based on values contained in the CH2M HILL coal plant estimating model database.

4.7 An Instrument Equipment list with quantities including CEMS and DCS was utilized to establish the equipment list for the estimate. Quantities for instruments and bulks were determined based on values contained in the CH2M HILL coal plant estimating model database.

4.8 Painting and Insulation quantities were derived from estimated quantities from the steel, equipment and piping accounts.

4.9 Buildings and Architectural – Based on quantities derived from General Arrangement Layouts and was broken out to include exterior and interior elements including doors, windows, siding, roofing, floors and wall finishes.

5.0 PRICING BASIS

5.1 Earthwork Account: Based on man-hour rates and costs experienced on other recently complete projects and on in-house estimating database information for manhours and bulk pricing.

5.2 Concrete Account: Manhours, formwork, reinforcing steel, finishing and grout based on in-house estimating database information. We have adjusted the ready-mix concrete price per cubic yard to $85.00 based on telephone quotes from local suppliers. Pricing for reinforcement material was adjusted to $.45 per pound to reflect recent price increases for this material.

5.2 Steel Account: Steel man-hour installation rates, piperack and miscellaneous steel, grating, handrail, checkered plate, ladders, stair treads and stringer were all based on costs experienced on other recently completed projects and on in-house estimating database information. The cost for steel has been adjusted to reflect the latest pricing being experienced for this material based on current quotes.

5.3 Equipment Account: Quotes were based on brief performance specifications in the form of one or two page data sheets prepared for each of the major equipment items. All quotes were stated in current dollars.

5.3.1 Steam Generator – (1) Each: Quotes received from Foster Wheeler & Alstom. Prices are quoted in present-day dollars. Foster Wheeler pricing was used as the basis for this estimate and the scope includes the steam generator, baghouse and SCR system.

5.3.2 Steam Turbine Generator – (1) each: 280 MW single reheat unit with two-flow exhaust: Equipment quotes were received from Alstom, Siemens, and GE. Siemens pricing was used as a basis for this estimate.

5.3.3 Air-Cooled Condenser - Pricing based budgetary written equipment quotes received from GEA and Marley . Marley was used as a basis for this estimate.

5.3.4 Coal Handling and Ash Handling Systems – A budgetary quote FMC was received and was used as a basis for the in-battery limits Coal Handling System costs. The FMC quote included equipment, erection, dust suppression, and sampling system costs. A budgetary quote from United Conveyor was used as a basis for the Ash Handling System cost and included costs for equipment.

5.3.5 Stack and Breeching – Pricing based budgetary written equipment quotes received from Hamon Custodis, Hoffman, and Gibraltar Chimney for the 500 foot Stack and Breeching. Hamon Custodis pricing was used.

5.3.6 Coal Storage Silos – Pricing was received from Hoffman for the Coal Storage silos.

The balance of equipment and installation rates were based on man-hour rates and costs experienced on other recently completed projects and on in-house estimating database information.

5.4 Piping Account: Pricing for pipe, fittings and shop fabrication was based on recently received pricing from Team Industries, Bendtec and International Piping. Pricing for Valves and Specialties and installation rates were based on recently completed projects and on in-house estimating data.

5.5 Electrical Account: The electrical equipment, installation man-hours, pricing for wire, terminations, conduit, tray, grounding and electrical heat tracing was based on man-hour rates, quotes received and costs experienced on other recently completed projects and on in-house database information.

5.6 Instrumentation Account: The instrumentation, DCS, CEMS and installation man-hours, and pricing for bulks was based on man-hour rates and costs experienced on other recently completed projects and on in-house database information.

5.7 Site Building Account: Unit prices based on recent project pricing and on database information for siding, roofing, building mechanical and electrical components and architectural elements.

6.0 LABOR

Open-shop craft labor rates were derived from published prevailing (union and non-union mix) wages for the area. A labor factor of 1.11 was assumed based on review of various factors including location, congestion, local labor conditions, weather and schedule. A fifty hour work week was assumed to attract craft with incidental overtime as required. A per diem of $40.00 was included.

7.0 SCHEDULE

Start Engineering:	May 2006
Start Construction:	May 2007
Mechanical Completion:	October 2010
COD	January 2011

Assumed was detailed engineering duration approximately 30 months (including procurement); construction duration 42 months with 9 months start-up. The total duration was assumed to be 57 months.

8.0 HOME OFFICE ENGINEERING SERVICES

Detailed engineering was calculated using wage rates by salary category including work by disciplines estimating the engineering production and support work-hours based on type and sequence for the work required. Additional expenses were added for reproduction, computers, outside services and travel. These engineering services apply to the BOP contractor only.

9.0 CONSTRUCTION INDIRECTS

Includes costs for Field Staff, Temporary Facilities, Construction Equipment and small tools/consumables, Heavy Hauling, Start-up Craft Assistance and temporary start-up supplies, spare parts and consumables.

10.0 CONTRACTOR'S CONTINGENCY

A contingency was included of 8% based on an assessment of major cost elements.

11.0 CONTRACTOR'S FEE

An 10% fee (including G & A) was applied based on all cost elements related to the BOP contract.

12.0 INCLUSIONS

Structural and civil works to the site battery limits
Piling
Mechanical and plant equipment
Bulks
Contractor's construction supervision
Temporary facilities
Construction power and water
Construction equipment, small tools and consumables
Start-up spare parts and start-up craft labor
Interest During Construction @ 6.5% lend rate.
230 kV Switchyard
Sales Tax @ 5.00%.
First fills
Contractor's Contingency and Fee
Insurances (Workers' Comp,Liability and Builders Risk)
Performance and Payment Bond Cost @ $.04/$1,000.

13.0 EXCLUSIONS

Demolition, soils remediation, moving of underground appurtenances or piping (unless noted otherwise), excavation at site location to depth required to reach undisturbed soil..
Delay in start-up insurance.
Plant Licenses or environmental permits.
Removal or relocation of existing facilities or structures (unless noted otherwise)
Dewatering except for runoff during construction.
No on-site fuel oil storage is included.
Risk assessment for determining probability of overrun or underrun is not included.

14.0 ASSUMPTIONS & QUALIFICATIONS

All excavated soil will be disposed of elsewhere on the site
This site does not contain any EPA defined hazardous or toxic wastes or any archaeological finds that would interrupt or delay the project.
Equipment is supplied with manufacturers standard paint
Craft parking is immediately adjacent to site
Craft bussing is not required.
Rock excavation is not required.
A construction or operating camp has not been included.
An ample supply of skilled craft is available within the vicinity of the site.
Startup fuel is natural gas.
The site has free and clear access with adequate laydown area immediately adjacent to the site.

15.0 INTERCONNECTS

ROADS:	Tie in to existing road at Battery Limit
WATER:	Well Field
ELECTRIC:	Battery Limit
VOLTAGE:	230 kV

16.0 SWITCHYARD

230 kV

17.0 SALES TAX

Tax rate is 5.00%.

CH2MHILL

Client: Basin Electric Power Cooperative
Project: CFB 200MW (gross) Coal Fired Plant
Location: Gillette, Wyoming
Job No.: 317334
Case:

Date: November 3, 2004
Estimator: R.J. Witherell
Rev. No.: 5

Account No.	Description	Quantity	Unit	MH/ Unit	MH Rate	Material Unit		Manhours	LABOR	MATERIAL	SPECIALTY SUBCONTRACTS	TOTAL	Size	Remarks
	EARTHWORK				$30.94			34,482	$1,066,882	$436,315	$10,517,044	$12,020,241		
	CONCRETE			7.13	$33.21	$199.50		203,831	$6,769,234	$5,700,477		$12,469,711	28,574 CY	
	STEEL			23.68	$31.18	$2,605.00		79,073	$2,465,487	$6,847,384		$9,312,871	2,629 TN	
	EQUIPMENT				$43.02			152,736	$6,570,698	$135,489,458	$109,060,572	$251,120,728		
	PIPING			2.40	$37.79	$79.90		259,984	$9,824,790	$8,662,526	$2,300,000	$20,787,316	108,423 LF	
	ELECTRICAL				$38.84			324,070	$12,586,881	$19,007,527		$31,594,407		
	INSTRUMENTATION & CONTROLS				$38.84			26,479	$1,028,464	$6,348,037		$7,376,501		
	PAINTING										$1,535,410	$1,535,410		
	INSULATION										$5,080,284	$5,080,284		
	BUILDINGS & ARCHITECTURAL										$7,100,551	$7,100,551		
	DIRECT FIELD COST				$37.30			1,080,656	$40,312,436	$182,491,723	$135,593,861	$358,398,019		
	FIELD STAFF & LEGALITIES											$14,130,097		
	TEMPORARY FACILITIES											$6,012,068		
	CONSTRUCTION CAMP													
	CONSTRUCTION EQUIPMENT, TOOLS, SUPPLIES											$9,940,888		
	START-UP TESTING AND TRAINING							26,334	$3,151,184	$150,000	$750,000	$4,051,184		
	INDIRECT FIELD COST							26,334	$3,151,184	$150,000	$750,000	$34,134,237		
	TOTAL FIELD COST											$392,532,256		
	EPC (Balance Of Plant) ENGINEERING						$96.39	147,147				$14,184,126		
	SUBTOTAL FIELD AND ENGINEERING											$406,716,382		
	FREIGHT											Included		
	SUBTOTAL											$406,716,382		
	CONTINGENCY						8.00%					$32,537,311		
	EPC (Balance Of Plant) CONTRACTOR'S FEE						10.00%					$21,216,533		
	SUBTOTAL											$460,470,226		
	SWITCHYARD											$4,624,028		
	TAXES						6.00%					$13,328,205	CAMPBELL COUNTY, WY	
	INSURANCES (Workers' Comp, Liability and Builders Risk)											$18,200,000	PER BEPC	
	PERMITS											$50,000	ALLOWANCE	
	PERFORMANCE BONDS						$.04/1000					$18,419	PER BEPC	
	TOTAL											$496,690,878		

CH2M HILL
Lockwood Greene

ESTIMATE BASIS

CLIENT:	Basin Electric Power Cooperative	ESTIMATOR:	R. J. Witherell
PROJECT:	250 MW (net) IGCC Power Plant	DATE:	10/27/05
LOCATION:	Gillette, Wyoming	REVISION:	0
Job No.:	317334		

1.0 PURPOSE

To prepare a Feasibility level Cost Estimate for engineering, procurement and construction (EPC) services for a 250 MW (net) IGCC Power Plant for Basin Electric Power Cooperative. An estimate of this type is expected to be accurate within +/-30% of the estimated cost.

2.0 SCOPE

The estimate has been broken down into a number of separate components described as follows:

2.1 COAL STORAGE & PREPARATION

The coal handling facility for this plant will be based on a mine-mouth delivery design with area allocated on-site for a future rail loop, rail coal delivery and unloading system. Coal Storage will be as follows: 10 days of dry storage and 10 days of outside storage will be provided. After reclaim, the coal will be conveyed to the Coal Gasification Plant storage hopper. Pricing has been obtained from recent quotes received from a major coal handling contractor and was based on supply and installation of the complete coal handling system as if it were located in the southeastern region of the United States. The installation portion of the quote was provided with labor costs and construction manhours allowing CH2M HILL/Lockwood Greene to adjust the installation cost to reflect the productivity and craft labor costs applicable to the Gillette, Wyoming location. The material and equipment portions of the quote were adjusted to reflect shipping cost differentials, etc. The coal preparation system includes an auxiliary boiler burning syngas and natural gas to generate steam for coal drying.

2.2 GASIFICATION SYSTEM

The design is based on gasification of coal delivered to the Gasification Plant storage hopper and will be using a gasification technology developed by Shell. The Shell gasification system supply and installation costs in terms of southeastern United States manhours, labor and material costs was developed from cost data published by DOE. The costs, as above for the Coal Handling System, were converted by CH2M HILL /Lockwood Greene to reflect the costs applicable for Gillette, Wyoming.

2.3 SULFINOL & SULFUR RECOVERY UNIT (SRU) (Gas Clean-up)

The syngas produced by the Gasification Process will be treated in a Sulfinol Gas treating unit that is licensed by Shell. The Sulfur Recovery Unit (SRU) pricing was provided by Shell. Shell has provided SRU supply and installation costs in terms of southeastern United States manhours, labor and material costs. The costs, as above for the Coal Handling System, were converted by CH2M HILL /Lockwood Greene to reflect the costs applicable for Gillette, Wyoming.

2.4 AIR SEPARATION PLANT

The Air Separation Unit (ASU) provides the oxygen required by the Gasifier. Air Products has provided a supply and installation costs in terms of southeastern United States manhours, labor and material costs. The costs, as above for the Coal Handling System, were converted by CH2M HILL/Lockwood Greene to reflect the costs applicable for Gillette, Wyoming.

2.5 POWER GENERATION PLANT

Gas produced by the above is utilized for combustion in the combined cycle plant gas turbines. Backup fuel will be natural gas. The plant will consist of one (1) GE 7 FA Combustion Turbine Generator, one (1) three-pressure Heat Recovery Steam Generator, and one (1) reheat 90MW Steam Turbine Generator with air cooled condenser. The total output will equal 250MW (net). The Power Generation Plant generally consists of:

CTG (GE 7 FA)
HRSG (three pressure)
STG (reheat)
Air Cooled Condenser
Water Treatment System
Civil Works
BOP Equipment
Field Erected Tanks
GSU Transformers
CEMS
DCS
Instrumentation & Controls
Electrical Equipment and Bulks including 230KV Switchyard
Pre-engineered Buildings

Quantities were derived based on the use of a new general arrangement drawing. Historical data was utilized to provide parametric checking of account values of the completed estimate.

2.5.1 Concrete Account: Foundation and slab on grade concrete quantities were based on equipment size and quantity information. Man-hours, formwork, reinforcing steel, concrete, finishing and grout based on in-house estimating database information.

2.5.2 Steel Account: Take-off of piperack and miscellaneous steel was based on the preliminary General Arrangement layout. Steel man-hour installation rates, piperack and miscellaneous steel, grating, handrail, checkered plate, ladders, stair treads and stringer were all based on costs experienced on other recently completed projects and on in-house estimating database information.

2.5.3 Equipment: Equipment quantities and capacities were determined based on a preliminary equipment list. Pricing based on quotes received for the following: CTG, HRSG, STG and Air Cooled Condenser. The balance of equipment pricing was based on historical information predicated on equipment sizing and capacities.

2.5.4 Piping: Large bore, major small bore and underground pipe quantities were derived from in-house estimating data and checked against the preliminary General Arrangement Drawing for lengths. Pricing for pipe, fittings, valves, hangers and specialties was based on recently received pricing from vendors.

Installation rates were based on man-hour rates experienced on recently completed projects and on in-house estimating data.

2.5.5 Electrical: Electrical equipment and bulk quantities were derived from motor list (for power wire, I/O count (for instrumentation and control wire) and a one-line. The electrical equipment, installation man-hours, pricing for wire, terminations, conduit, tray and grounding was based on man-hour rates and costs experienced on other recently completed projects and on in-house database information.

2.5.6 Instrumentation: Instrumentation and bulk quantities were derived from in-house estimating data. The instrumentation, DCS, CEMS and installation man-hours, and pricing for bulks was based on man-hour rates and costs experienced on other recently completed projects and on in-house database information.

2.5.7 Painting and Insulation: Quantities were derived from estimated quantities from the steel, equipment and piping accounts. Pricing was based on in-house database information.

2.5.8 Buildings & Architectural: Pricing for the pre-engineered Control/Warehouse/Maintenance Building was based on square footage pricing recently received for a similar building for a recently bid project.

2.6 INFRASTRUCTURE

The plant infrastructure includes interconnections between areas and process units in terms of piping and required utility interfaces. It also addresses overall site development, civil work required and interfaces required for offsite including, utilities and roads. Sitework was based on a preliminary General Arrangement layout which was used to determine site clearing, cut and fill quantities, paving, gravel, underground/aboveground utilities, and site drainage. Sitework costs were based on man-hour rates and costs experienced on other recently complete projects and on in-house estimating database information for man-hours and bulk pricing. Interconnect piping, electrical, etc. was developed based on the various vendor requirements for each plant area (i.e. Pipe sizes, electrical loads).

3.0 CONSTRUCTION APPROACH

The estimate is based on a direct-hire open-shop craft labor (mix of Union and Non-union craft) with multiple EPC contractors for the following:

- Coal Handling Contractor
- Gasification Plant Contractor
- Air Separation Plant Contractor
- Sulfur Plant Contractor
- Sulfinol Plant Contractor
- Power Generation Plant Contractor
- Air Cooled Condenser Contractor
- Balance of Plant BOP and Infrastructure Contractor
- Switchyard

4.0 CRAFT LABOR

Open-shop craft labor rates were derived from published prevailing (union and non-union mix) wages for the area. A labor factor of 1.11 was assumed based on review of various factors including location, congestion, local labor conditions, weather and schedule. A fifty hour work week was assumed to attract craft with incidental overtime as required. A per diem of $40.00 was included.

5.0 SCHEDULE

Start Engineering:	May 2006
Start Construction:	May 2007
Mechanical Completion:	October 2010
COD	January 2011

Assumed was detailed engineering duration approximately 30 months (including procurement); construction duration 42 months with 9 months start-up. The total duration was assumed to be 57 months.

6.0 ESCALATION

Escalation is calculated per the schedule and calculated to the delivery dates for equipment and materials and through mid-point of construction for labor and subcontracts.

7.0 HOME OFFICE ENGINEERING SERVICES

Detailed engineering was calculated using wage rates by salary category including work by disciplines estimating the engineering production and support work-hours based on type and sequence for the work required. Additional expenses were added for reproduction, computers, outside services and travel. These engineering services apply to the BOP/ Infrastructure contractor only.

8.0 CONSTRUCTION INDIRECTS

Includes costs for Field Staff, Temporary Facilities, Construction Equipment and small tools/consumables, Heavy Hauling, Start-up Craft Assistance and temporary start-up supplies, spare parts and consumables.

9.0 CONTINGENCY

A contingency was included of 10% based on an assessment of major cost elements.

10.0 CONTRACTOR'S FEE

A 10% Fee (including G & A) was applied based on all cost elements related to the BOP contract.

11.0 INCLUSIONS

Structural and civil works to the site battery limits
Piling
Mechanical and plant equipment
Bulks
Contractor's construction supervision
Temporary facilities
Construction power and water
Construction equipment, small tools and consumables

Start-up spare parts and start-up craft labor
Interest during Construction @ 6.5% lend rate.
230 kV Switchyard
Sales Tax @ 5.00%.
Escalation
First fills
Contractor's Contingency and Fee
Insurances (Workers' Comp, Liability and Builders Risk)
Performance and Payment Bond Cost @ $.04/$1,000.

12.0 EXCLUSIONS

Demolition, soils remediation, moving of underground appurtenances or piping (unless noted otherwise), excavation at site location to depth required to reach undisturbed soil.
Delay in start-up insurance.
Plant Licenses or environmental permits.
Removal or relocation of existing facilities or structures (unless noted otherwise)
Dewatering except for runoff during construction.
No on-site fuel oil storage is included.
Risk assessment for determining probability of overrun or underrun is not included.

13.0 ASSUMPTIONS & QUALIFICATIONS

All excavated soil will be disposed of elsewhere on the site
This site does not contain any EPA defined hazardous or toxic wastes or any archaeological finds that would interrupt or delay the project.
Equipment is supplied with manufacturer's standard paint
Craft parking is immediately adjacent to site
Craft bussing is not required.
Rock excavation is not required.
A construction or operating camp has not been included.
An ample supply of skilled craft is available within the vicinity of the site.
Startup fuel is natural gas.
The site has free and clear access with adequate laydown area immediately adjacent to the site.

14.0 INTERCONNECTS

ROADS:	Tie in to existing road at Battery Limit
WATER:	Well Field
ELECTRIC:	Battery Limit
VOLTAGE:	230 kV

15.0 SWITCHYARD

230 kV

16.0 SALES TAX

Tax rate is 5.00%.

CH2M HILL / Lockwood Greene

Client: Basin Electric Power Cooperative
Project: Dry Fork Station - 250 MW IGCC Plant
Location: Gillette, Wyoming
Job No.:
Case:

Date: October 27, 2005
Estimator: R.J. Witherell
Rev. No.: 0

Account No.	Description	Quantity	Unit	MH/ Unit	MH Rate	Material Unit		Subcontract Manhours	LABOR	MATERIAL	SPECIALTY SUBCONTRACTS	TOTAL	Size	SUMMARY
	COAL HANDLING SYSTEM				$52.07			155,475	$8,094,812	$22,365,075		$30,459,888		
	GASIFICATION SYSTEM				$42.16			694,141	$29,265,005	$87,795,015		$117,060,020		
	SULFINOL				$43.45			304,641	$13,237,688	$38,218,063		$51,455,750		
	AIR SEPARATION PLANT				$42.16			341,981	$14,417,910	$33,641,790		$48,059,700		
	POWER GENERATION PLANT				$38.31			539,424	$20,665,156	$97,711,243	$7,060,055	$125,436,454		
	INFRASTRUCTURE				$37.42			429,535	$16,074,678	$36,364,305	$14,423,739	$66,862,722		
	WASTE WATER TREATMENT				$42.16			183,810	$7,749,444	$23,248,333		$30,997,777		
	DIRECT FIELD COST				$41.34			2,649,008	$109,504,693	$339,343,824	$21,483,794	$470,332,311		
	FIELD STAFF											$21,978,101		
	TEMPORARY FACILITIES											$12,334,906		
	CONSTRUCTION EQUIPMENT, SMALL TOOLS, CONSUMABLES											$20,475,000		
	START-UP TESTING AND TRAINING											$8,000,000		
	INDIRECT FIELD COST											$62,788,007		
	TOTAL FIELD COST											$533,120,317		
	FEED & DETAILED ENGINEERING											$15,690,350		
	GAS CLEANING AND GASIFIER LICENSING AGREEMENT											$5,055,473		
	TOTAL FIELD AND EPC ENGINEERING											$553,866,140		
	CONTINGENCY						10.00%					$61,994,278		
	EPC CONTRACTOR'S FEE						10.00%					$61,617,300		
	SUBTOTAL											$677,477,718		
	SWITCHYARD											$4,781,971		
	TAXES						5.00%					$17,504,286	CAMPBELL COUNTY, WY	
	INSURANCES (Workers' Comp., Liability and Builders Risk)											$20,000,000	PER BEPC	
	PERMITS											$50,000	ALLOWANCE	
	PERFORMANCE BONDS						$.04/1000					$28,793	PER BEPC	
	ESCALATION													
	TOTAL											$719,842,768		

Appendix E Economic Evaluations

ECONOMIC ANALYSIS SUMMARY

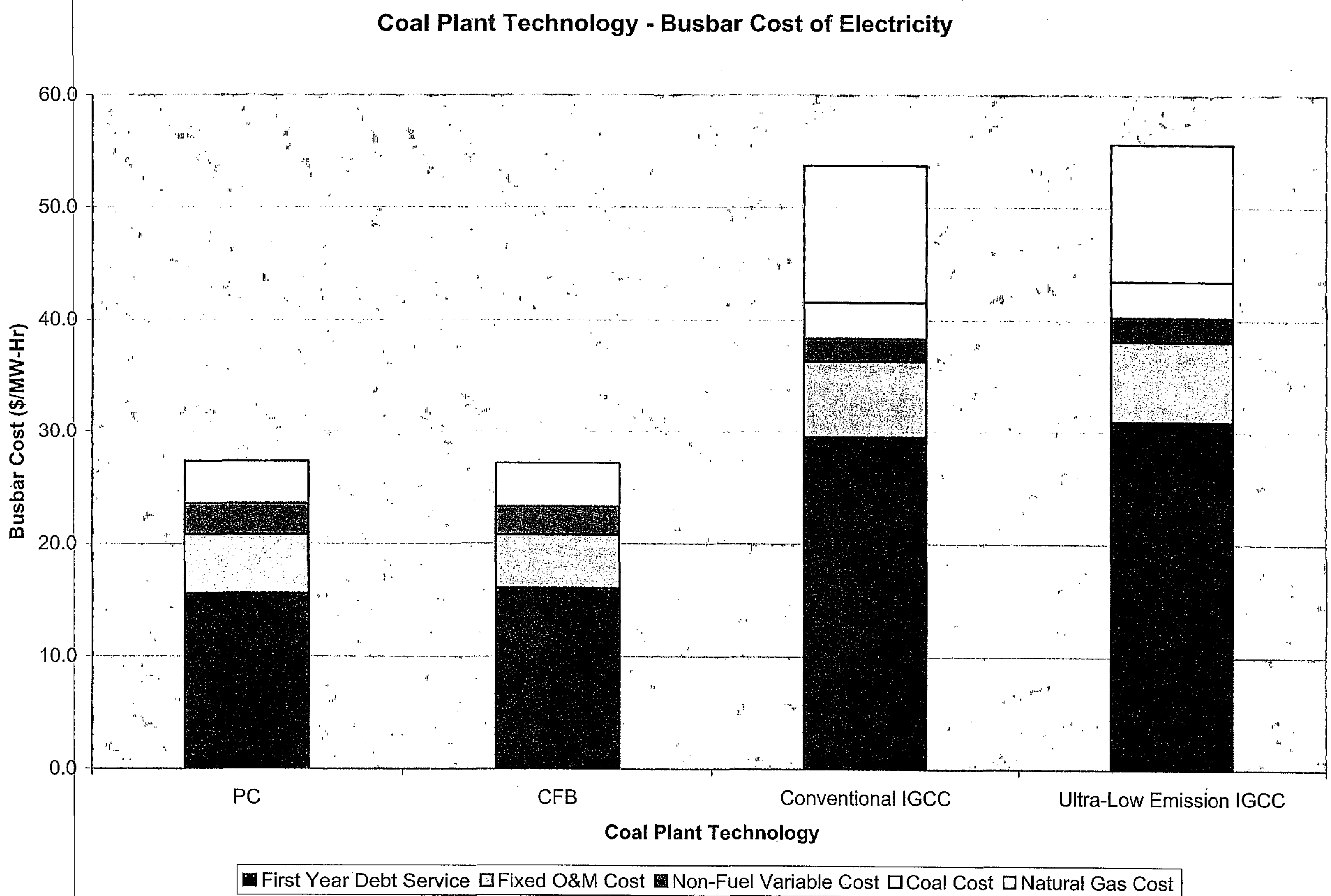
Basin Electric Power Cooperative NE Wyoming Project

Parameter	PC	CFB	Conventional IGCC	Ultra-Low Emission IGCC
Total Capital Cost ($)	482,000,000	497,000,000	720,000,000	756,000,000
First Year Costs ($)				
Fixed O&M Cost	10,673,372	9,606,870	13,923,000	14,619,150
Non-Fuel Variable Cost	5,639,684	5,183,533	4,146,826	4,354,168
Coal Cost	7,619,793	7,837,502	6,476,824	6,476,824
Natural Gas Cost	0	0	24,732,312	24,732,312
TOTAL FIRST YEAR OPERATING COST	**23,932,849**	**22,627,905**	**49,278,963**	**50,182,454**
FIRST YEAR DEBT SERVICE ($)	31,659,406	32,644,657	59,966,525	62,964,852
TOTAL FIRST YEAR COST ($)	**55,592,255**	**55,272,562**	**109,245,488**	**113,147,306**
Total Pollutant Emissions (Ton/Yr)	**3,657**	**3,981**	**1,491**	**804**
Incremental Pollutants Removed (Ton/Yr)	**Base**	**-324**	**2,166**	**2,853**
First Year Incremental Pollutant Control Cost ($/Ton Removed)	**Base**	987	**24,767**	**20,173**
NET PRESENT VALUE ($)	**961,390,166**	**950,251,303**	**1,982,192,789**	**2,045,938,442**

DEQ/AQD 001970

BUSBAR COST ($/MW-Hr)

Parameter	PC	CFB	Conventional IGCC	Ultra-Low Emission IGCC
First Year Costs ($/MW-Hr)				
Fixed O&M Cost	5.3	4.7	6.8	7.2
Non-Fuel Variable Cost	2.8	2.6	2.0	2.1
Coal Cost	3.7	3.9	3.2	3.2
Natural Gas Cost	0.0	0.0	12.2	12.2
First Year Debt Service	15.6	16.1	29.5	31.0
Total First Year Cost	**27.3**	**27.2**	**53.7**	**55.7**



DEQ/AQD 001971

INPUT CALCULATIONS

Basin Electric Power Cooperative NE Wyoming Project

Parameter	PC	CFB	Conventional IGCC	Ultra-Low Emission IGCC	Comments
Plant Design					
Type of Unit	Pulverized Coal	Circulating Fluid Bed	IGCC	IGCC	
SO2 Control System	CDS FGD	CDS FGD	Syngas MDEA (H2S)	Syngas Selexol (H2S)	
NOx Control System	HD SCR	SNCR	CTG Nitrogen Dilution	CTG SCR	
CO and VOC Control System	Good Combustion Practices	Good Combustion Practices	Good Combustion Practices	Cat-Ox	
PM Control System	Fabric Filter	Fabric Filter	Syngas Filters/Scrubbers	Syngas Filters/Scrubbers	
Net Power Output @ Annual Average (kW)	273,000	273,000	273,000	273,000	Annual Average
Net Plant Heat Rate @ Annual Average (Btu/kW-Hr)	10,500	10,800	10,500	10,500	Annual Average
Natural Gas Firing (%)	0%	0%	15%	15%	
Natural Gas Heating Value (Btu/Lb)	19,500	19,500	19,500	19,500	Pipeline Quality Natural Gas
Design Heat Input (MMBtu/Hr)	2,867	2,948	2,867	2,867	
Fuel Usage					
Coal Flow Rate (Lb/Hr)	356,308	366,489	302,862	302,862	Calculated
(Ton/Yr)	1,326,536	1,364,437	1,127,555	1,127,555	Calculated
(MMBtu/Yr)	21,343,959	21,953,786	18,142,365	18,142,365	Calculated
Natural Gas Flow Rate (Lb/Hr)	0	0	22,050	22,050	Calculated
(MMBtu/Yr)	0	0	3,201,594	3,201,594	Calculated
Pollutant Emissions (Tons/Yr)					
NOx	747.0	987.9	747.1	373.5	From Coal Emissions Workbook
SO2	1,067.2	1,097.6	263.7	131.8	From Coal Emissions Workbook
CO	1,600.8	1,646.5	320.2	160.1	From Coal Emissions Workbook
VOC	39.5	40.6	42.7	21.3	From Coal Emissions Workbook
PM	202.8	208.6	117.4	117.4	From Coal Emissions Workbook
Total Pollutant Emissions (Ton/Yr)	3,657.3	3,981.2	1,491.0	804.2	Calculated
General Plant Data					
Annual Operation (Hours/Year)	7,446	7,446	7,446	7,446	Calculated
Annual On-Site Power Plant Capacity Facto	85.0%	85.0%	85.0%	85.0%	Design Basis
Economic Factors					
Interest Rate (%)	6.0%	6.0%	8.0%	8.0%	Higher rate for IGCC due to risk
Discount Rate (%)	6.0%	6.0%	6.0%	6.0%	Assumed
Plant Economic Life (Years)	42	42	42	42	Assumed
Capital Costs					
Total Capital Cost ($)	482,000,000	497,000,000	720,000,000	756,000,000	Estimated
($/kW)	1,766	1,821	2,637	2,769	Calculated
Fixed and Variable O&M Costs					
Fixed O&M Costs ($/kW-Yr)	$38.33	$34.50	$50.00	$52.50	Typical costs for each technology
($)	$10,464,090	$9,418,500	$13,650,000	$14,332,500	Calculated
Non-Fuel Variable O&M Costs ($/kW-Hr)	$0.0027	$0.0025	$0.0020	$0.0021	Typical costs for each technology
($)	$5,529,102	$5,081,895	$4,065,516	$4,268,792	Calculated
Annual Non-Fuel O&M Cost Escalation Rate (%)	2.0%	2.0%	2.0%	2.0%	Design Basis
Powder River Basin (PRB) Fuel Cost					
Dry Fork Coal Mine					
Coal Heating Value, HHV (Btu/Lb)	8,045	8,045	8,045	8,045	Design Basis
Coal Sulfur Content (wt.%)	0.47%	0.47%	0.47%	0.47%	Design Basis
Coal Ash Content (wt.%)	4.77%	4.77%	4.77%	4.77%	Design Basis
Mine Mouth Coal Cost ($/Ton)	$5.63	$5.63	$5.63	$5.63	Calculated
($/MMBtu)	$0.35	$0.35	$0.35	$0.35	From Dry Fork Mine
Annual Coal Cost Escalation Rate (%)	2.0%	2.0%	2.0%	2.0%	Design Basis
Natural Gas Cost					
Unit Cost ($/MMBTU)	7.50	7.50	7.50	7.50	Assumed
Annual Natural Gas Cost Escalation Rate (%)	3.0%	3.0%	3.0%	3.0%	Design Basis

Pro Forma PC

Year	Date	Fixed O&M Cost	Non-Fuel Variable Cost	Coal Cost	Natural Gas Cost	TOTAL OPERATING COST	DEBT SERVICE	TOTAL ANNUAL COST	Pollutant Control Cost ($/Ton Removed)
0									
1	2006	10,673,372	5,639,684	7,619,793	-	23,932,849	31,659,406	55,592,255	15,200
2	2007	10,886,839	5,752,477	7,772,189	-	24,411,506	31,659,406	56,070,912	15,331
3	2008	11,104,576	5,867,527	7,927,633	-	24,899,736	31,659,406	56,559,142	15,465
4	2009	11,326,668	5,984,878	8,086,186	-	25,397,731	31,659,406	57,057,137	15,601
5	2010	11,553,201	6,104,575	8,247,909	-	25,905,685	31,659,406	57,565,092	15,740
6	2011	11,784,265	6,226,667	8,412,868	-	26,423,799	31,659,406	58,083,205	15,881
7	2012	12,019,950	6,351,200	8,581,125	-	26,952,275	31,659,406	58,611,681	16,026
8	2013	12,260,349	6,478,224	8,752,747	-	27,491,321	31,659,406	59,150,727	16,173
9	2014	12,505,556	6,607,788	8,927,802	-	28,041,147	31,659,406	59,700,553	16,324
10	2015	12,755,667	6,739,944	9,106,358	-	28,601,970	31,659,406	60,261,376	16,477
11	2016	13,010,781	6,874,743	9,288,486	-	29,174,009	31,659,406	60,833,415	16,633
12	2017	13,270,996	7,012,238	9,474,255	-	29,757,490	31,659,406	61,416,896	16,793
13	2018	13,536,416	7,152,483	9,663,740	-	30,352,639	31,659,406	62,012,045	16,956
14	2019	13,807,145	7,295,532	9,857,015	-	30,959,692	31,659,406	62,619,098	17,122
15	2020	14,083,287	7,441,443	10,054,156	-	31,578,886	31,659,406	63,238,292	17,291
16	2021	14,364,953	7,590,272	10,255,239	-	32,210,464	31,659,406	63,869,870	17,464
17	2022	14,652,252	7,742,077	10,460,343	-	32,854,673	31,659,406	64,514,079	17,640
18	2023	14,945,297	7,896,919	10,669,550	-	33,511,766	31,659,406	65,171,173	17,820
19	2024	15,244,203	8,054,857	10,882,941	-	34,182,002	31,659,406	65,841,408	18,003
20	2025	15,549,087	8,215,954	11,100,600	-	34,865,642	31,659,406	66,525,048	18,190
21	2026	15,860,069	8,380,273	11,322,612	-	35,562,955	31,659,406	67,222,361	18,380
22	2027	16,177,270	8,547,879	11,549,064	-	36,274,214	31,659,406	67,933,620	18,575
23	2028	16,500,816	8,718,836	11,780,046	-	36,999,698	31,659,406	68,659,104	18,773
24	2029	16,830,832	8,893,213	12,015,647	-	37,739,692	31,659,406	69,399,098	18,976
25	2030	17,167,449	9,071,077	12,255,959	-	38,494,486	31,659,406	70,153,892	19,182
26	2031	17,510,798	9,252,499	12,501,079	-	39,264,375	31,659,406	70,923,782	19,392
27	2032	17,861,014	9,437,549	12,751,100	-	40,049,663	31,659,406	71,709,069	19,607
28	2033	18,218,234	9,626,300	13,006,122	-	40,850,656	31,659,406	72,510,062	19,826
29	2034	18,582,599	9,818,826	13,266,245	-	41,667,669	31,659,406	73,327,075	20,050
30	2035	18,954,251	10,015,203	13,531,570	-	42,501,023	31,659,406	74,160,429	20,277
31	2036	19,333,336	10,215,507	13,802,201	-	43,351,043	31,659,406	75,010,449	20,510
32	2037	19,720,002	10,419,817	14,078,245	-	44,218,064	31,659,406	75,877,470	20,747
33	2038	20,114,402	10,628,213	14,359,810	-	45,102,425	31,659,406	76,761,831	20,989
34	2039	20,516,690	10,840,777	14,647,006	-	46,004,474	31,659,406	77,663,880	21,235
35	2040	20,927,024	11,057,593	14,939,946	-	46,924,563	31,659,406	78,583,969	21,487
36	2041	21,345,565	11,278,745	15,238,745	-	47,863,055	31,659,406	79,522,461	21,744
37	2042	21,772,476	11,504,320	15,543,520	-	48,820,316	31,659,406	80,479,722	22,005
38	2043	22,207,926	11,734,406	15,854,390	-	49,796,722	31,659,406	81,456,128	22,272
39	2044	22,652,084	11,969,094	16,171,478	-	50,792,656	31,659,406	82,452,063	22,545
40	2045	23,105,126	12,208,476	16,494,908	-	51,808,510	31,659,406	83,467,916	22,822
41	2046	23,567,228	12,452,646	16,824,806	-	52,844,680	31,659,406	84,504,086	23,106
42	2047	24,038,573	12,701,698	17,161,302	-	53,901,573	31,659,406	85,560,979	23,395
NPV		213,794,417	112,966,449	152,629,301	-	479,390,166	482,000,000	961,390,166	6,259
(% of NPV)		22.2%	11.8%	15.9%	0.0%	49.9%	50.1%	100.0%	

DEQ/AQD 001973

Pro Forma CFB

Year	Date	Fixed O&M Cost	Non-Fuel Variable Cost	Coal Cost	Natural Gas Cost	TOTAL OPERATING COST	DEBT SERVICE	TOTAL ANNUAL COST	Pollutant Control Cost ($/Ton Removed)
0									
1	2006	9,606,870	5,183,533	7,837,502	-	22,627,905	32,644,657	55,272,562	13,884
2	2007	9,799,007	5,287,204	7,994,252	-	23,080,463	32,644,657	55,725,120	13,997
3	2008	9,994,988	5,392,948	8,154,137	-	23,542,072	32,644,657	56,186,729	14,113
4	2009	10,194,887	5,500,807	8,317,220	-	24,012,913	32,644,657	56,657,571	14,231
5	2010	10,398,785	5,610,823	8,483,564	-	24,493,172	32,644,657	57,137,829	14,352
6	2011	10,606,761	5,723,039	8,653,235	-	24,983,035	32,644,657	57,627,692	14,475
7	2012	10,818,896	5,837,500	8,826,300	-	25,482,696	32,644,657	58,127,353	14,601
8	2013	11,035,274	5,954,250	9,002,826	-	25,992,350	32,644,657	58,637,007	14,729
9	2014	11,255,979	6,073,335	9,182,882	-	26,512,197	32,644,657	59,156,854	14,859
10	2015	11,481,099	6,194,802	9,366,540	-	27,042,441	32,644,657	59,687,098	14,992
11	2016	11,710,721	6,318,698	9,553,871	-	27,583,289	32,644,657	60,227,947	15,128
12	2017	11,944,935	6,445,072	9,744,948	-	28,134,955	32,644,657	60,779,613	15,267
13	2018	12,183,834	6,573,973	9,939,847	-	28,697,654	32,644,657	61,342,312	15,408
14	2019	12,427,511	6,705,453	10,138,644	-	29,271,607	32,644,657	61,916,265	15,552
15	2020	12,676,061	6,839,562	10,341,417	-	29,857,040	32,644,657	62,501,697	15,699
16	2021	12,929,582	6,976,353	10,548,245	-	30,454,180	32,644,657	63,098,838	15,849
17	2022	13,188,174	7,115,880	10,759,210	-	31,063,264	32,644,657	63,707,921	16,002
18	2023	13,451,937	7,258,197	10,974,395	-	31,684,529	32,644,657	64,329,187	16,158
19	2024	13,720,976	7,403,361	11,193,882	-	32,318,220	32,644,657	64,962,877	16,318
20	2025	13,995,396	7,551,429	11,417,760	-	32,964,584	32,644,657	65,609,242	16,480
21	2026	14,275,303	7,702,457	11,646,115	-	33,623,876	32,644,657	66,268,533	16,646
22	2027	14,560,810	7,856,506	11,879,038	-	34,296,354	32,644,657	66,941,011	16,814
23	2028	14,852,026	8,013,636	12,116,618	-	34,982,281	32,644,657	67,626,938	16,987
24	2029	15,149,066	8,173,909	12,358,951	-	35,681,926	32,644,657	68,326,584	17,163
25	2030	15,452,048	8,337,387	12,606,130	-	36,395,565	32,644,657	69,040,222	17,342
26	2031	15,761,089	8,504,135	12,858,252	-	37,123,476	32,644,657	69,768,133	17,525
27	2032	16,076,310	8,674,218	13,115,417	-	37,865,946	32,644,657	70,510,603	17,711
28	2033	16,397,836	8,847,702	13,377,726	-	38,623,264	32,644,657	71,267,922	17,901
29	2034	16,725,793	9,024,656	13,645,280	-	39,395,730	32,644,657	72,040,387	18,095
30	2035	17,060,309	9,205,149	13,918,186	-	40,183,644	32,644,657	72,828,302	18,293
31	2036	17,401,515	9,389,252	14,196,550	-	40,987,317	32,644,657	73,631,975	18,495
32	2037	17,749,546	9,577,037	14,480,481	-	41,807,064	32,644,657	74,451,721	18,701
33	2038	18,104,536	9,768,578	14,770,090	-	42,643,205	32,644,657	75,287,862	18,911
34	2039	18,466,627	9,963,950	15,065,492	-	43,496,069	32,644,657	76,140,726	19,125
35	2040	18,835,960	10,163,229	15,366,802	-	44,365,990	32,644,657	77,010,648	19,344
36	2041	19,212,679	10,366,493	15,674,138	-	45,253,310	32,644,657	77,897,967	19,567
37	2042	19,596,933	10,573,823	15,987,621	-	46,158,376	32,644,657	78,803,034	19,794
38	2043	19,988,871	10,785,300	16,307,373	-	47,081,544	32,644,657	79,726,201	20,026
39	2044	20,388,649	11,001,006	16,633,520	-	48,023,175	32,644,657	80,667,832	20,262
40	2045	20,796,422	11,221,026	16,966,191	-	48,983,638	32,644,657	81,628,296	20,504
41	2046	21,212,350	11,445,446	17,305,515	-	49,963,311	32,644,657	82,607,968	20,750
42	2047	21,636,597	11,674,355	17,651,625	-	50,962,577	32,644,657	83,607,235	21,001
	NPV	192,431,708	103,829,456	156,990,138	-	453,251,303	497,000,000	950,251,303	5,683
	(% of NPV)	20.3%	10.9%	16.5%	0.0%	47.7%	52.3%	100.0%	

Pro Forma Conventional IGCC

Year	Date	Fixed O&M Cost	Non-Fuel Variable Cost	Coal Cost	Natural Gas Cost	TOTAL OPERATING COST	DEBT SERVICE	TOTAL ANNUAL COST	Pollutant Control Cost ($/Ton Removed)
0									
1	2006	13,923,000	4,146,826	6,476,824	24,732,312	49,278,963	59,966,525	109,245,488	73,271
2	2007	14,201,460	4,229,763	6,606,361	25,474,282	50,511,866	59,966,525	110,478,391	74,098
3	2008	14,485,489	4,314,358	6,738,488	26,238,510	51,776,846	59,966,525	111,743,371	74,947
4	2009	14,775,199	4,400,645	6,873,258	27,025,666	53,074,768	59,966,525	113,041,293	75,817
5	2010	15,070,703	4,488,658	7,010,723	27,836,436	54,406,520	59,966,525	114,373,045	76,710
6	2011	15,372,117	4,578,431	7,150,937	28,671,529	55,773,014	59,966,525	115,739,540	77,627
7	2012	15,679,559	4,670,000	7,293,956	29,531,675	57,175,190	59,966,525	117,141,715	78,567
8	2013	15,993,151	4,763,400	7,439,835	30,417,625	58,614,011	59,966,525	118,580,536	79,532
9	2014	16,313,014	4,858,668	7,588,632	31,330,154	60,090,467	59,966,525	120,056,992	80,523
10	2015	16,639,274	4,955,841	7,740,405	32,270,058	61,605,578	59,966,525	121,572,103	81,539
11	2016	16,972,059	5,054,958	7,895,213	33,238,160	63,160,390	59,966,525	123,126,915	82,582
12	2017	17,311,500	5,156,057	8,053,117	34,235,305	64,755,979	59,966,525	124,722,505	83,652
13	2018	17,657,731	5,259,178	8,214,179	35,262,364	66,393,452	59,966,525	126,359,977	84,750
14	2019	18,010,885	5,364,362	8,378,463	36,320,235	68,073,945	59,966,525	128,040,470	85,877
15	2020	18,371,103	5,471,649	8,546,032	37,409,842	69,798,626	59,966,525	129,765,151	87,034
16	2021	18,738,525	5,581,082	8,716,953	38,532,137	71,568,697	59,966,525	131,535,222	88,221
17	2022	19,113,295	5,692,704	8,891,292	39,688,101	73,385,392	59,966,525	133,351,918	89,440
18	2023	19,495,561	5,806,558	9,069,118	40,878,744	75,249,981	59,966,525	135,216,506	90,690
19	2024	19,885,473	5,922,689	9,250,500	42,105,106	77,163,768	59,966,525	137,130,294	91,974
20	2025	20,283,182	6,041,143	9,435,510	43,368,260	79,128,095	59,966,525	139,094,620	93,291
21	2026	20,688,846	6,161,966	9,624,220	44,669,307	81,144,339	59,966,525	141,110,864	94,644
22	2027	21,102,623	6,285,205	9,816,705	46,009,387	83,213,919	59,966,525	143,180,444	96,032
23	2028	21,524,675	6,410,909	10,013,039	47,389,668	85,338,291	59,966,525	145,304,817	97,456
24	2029	21,955,168	6,539,127	10,213,300	48,811,358	87,518,954	59,966,525	147,485,479	98,919
25	2030	22,394,272	6,669,910	10,417,566	50,275,699	89,757,446	59,966,525	149,723,972	100,420
26	2031	22,842,157	6,803,308	10,625,917	51,783,970	92,055,352	59,966,525	152,021,878	101,962
27	2032	23,299,000	6,939,374	10,838,435	53,337,489	94,414,299	59,966,525	154,380,824	103,544
28	2033	23,764,980	7,078,162	11,055,204	54,937,614	96,835,960	59,966,525	156,802,485	105,168
29	2034	24,240,280	7,219,725	11,276,308	56,585,742	99,322,055	59,966,525	159,288,581	106,835
30	2035	24,725,086	7,364,120	11,501,834	58,283,315	101,874,354	59,966,525	161,840,879	108,547
31	2036	25,219,587	7,511,402	11,731,871	60,031,814	104,494,674	59,966,525	164,461,199	110,305
32	2037	25,723,979	7,661,630	11,966,508	61,832,768	107,184,886	59,966,525	167,151,411	112,109
33	2038	26,238,459	7,814,863	12,205,838	63,687,751	109,946,911	59,966,525	169,913,436	113,962
34	2039	26,763,228	7,971,160	12,449,955	65,598,384	112,782,727	59,966,525	172,749,252	115,864
35	2040	27,298,492	8,130,583	12,698,954	67,566,335	115,694,365	59,966,525	175,660,890	117,816
36	2041	27,844,462	8,293,195	12,952,933	69,593,326	118,683,916	59,966,525	178,650,441	119,822
37	2042	28,401,351	8,459,059	13,211,992	71,681,125	121,753,527	59,966,525	181,720,053	121,880
38	2043	28,969,379	8,628,240	13,476,232	73,831,559	124,905,409	59,966,525	184,871,934	123,994
39	2044	29,548,766	8,800,804	13,745,757	76,046,506	128,141,833	59,966,525	188,108,358	126,165
40	2045	30,139,741	8,976,821	14,020,672	78,327,901	131,465,135	59,966,525	191,431,660	128,394
41	2046	30,742,536	9,156,357	14,301,085	80,677,738	134,877,716	59,966,525	194,844,242	130,683
42	2047	31,357,387	9,339,484	14,587,107	83,098,070	138,382,048	59,966,525	198,348,573	133,033
	NPV	278,886,534	83,063,565	129,734,906	577,544,822	1,069,229,826	912,962,962	1,982,192,789	31,654
(% of NPV)		14.1%	4.2%	6.5%	29.1%	53.9%	46.1%	100.0%	

Pro Forma Ultra-Low Emission IGCC

Year	Date	Fixed O&M Cost	Non-Fuel Variable Cost	Coal Cost	Natural Gas Cost	TOTAL OPERATING COST	DEBT SERVICE	TOTAL ANNUAL COST	Pollutant Control Cost ($/Ton Removed)
0									
1	2006	14,619,150	4,354,168	6,476,824	24,732,312	50,182,454	62,964,852	113,147,306	140,698
2	2007	14,911,533	4,441,251	6,606,361	25,474,282	51,433,427	62,964,852	114,398,278	142,254
3	2008	15,209,764	4,530,076	6,738,488	26,238,510	52,716,838	62,964,852	115,681,690	143,850
4	2009	15,513,959	4,620,678	6,873,258	27,025,666	54,033,560	62,964,852	116,998,411	145,487
5	2010	15,824,238	4,713,091	7,010,723	27,836,436	55,384,488	62,964,852	118,349,339	147,167
6	2011	16,140,723	4,807,353	7,150,937	28,671,529	56,770,542	62,964,852	119,735,393	148,891
7	2012	16,463,537	4,903,500	7,293,956	29,531,675	58,192,668	62,964,852	121,157,520	150,659
8	2013	16,792,808	5,001,570	7,439,835	30,417,625	59,651,838	62,964,852	122,616,690	152,474
9	2014	17,128,664	5,101,601	7,588,632	31,330,154	61,149,051	62,964,852	124,113,903	154,335
10	2015	17,471,238	5,203,633	7,740,405	32,270,058	62,685,334	62,964,852	125,650,185	156,246
11	2016	17,820,662	5,307,706	7,895,213	33,238,160	64,261,741	62,964,852	127,226,593	158,206
12	2017	18,177,076	5,413,860	8,053,117	34,235,305	65,879,357	62,964,852	128,844,209	160,218
13	2018	18,540,617	5,522,137	8,214,179	35,262,364	67,539,298	62,964,852	130,504,149	162,282
14	2019	18,911,429	5,632,580	8,378,463	36,320,235	69,242,707	62,964,852	132,207,559	164,400
15	2020	19,289,658	5,745,232	8,546,032	37,409,842	70,990,764	62,964,852	133,955,615	166,574
16	2021	19,675,451	5,860,136	8,716,953	38,532,137	72,784,677	62,964,852	135,749,529	168,804
17	2022	20,068,960	5,977,339	8,891,292	39,688,101	74,625,692	62,964,852	137,590,544	171,094
18	2023	20,470,339	6,096,886	9,069,118	40,878,744	76,515,087	62,964,852	139,479,939	173,443
19	2024	20,879,746	6,218,824	9,250,500	42,105,106	78,454,176	62,964,852	141,419,028	175,854
20	2025	21,297,341	6,343,200	9,435,510	43,368,260	80,444,311	62,964,852	143,409,162	178,329
21	2026	21,723,288	6,470,064	9,624,220	44,669,307	82,486,880	62,964,852	145,451,731	180,869
22	2027	22,157,754	6,599,465	9,816,705	46,009,387	84,583,310	62,964,852	147,548,162	183,476
23	2028	22,600,909	6,731,455	10,013,039	47,389,668	86,735,070	62,964,852	149,699,922	186,152
24	2029	23,052,927	6,866,084	10,213,300	48,811,358	88,943,669	62,964,852	151,908,520	188,898
25	2030	23,513,985	7,003,405	10,417,566	50,275,699	91,210,655	62,964,852	154,175,507	191,717
26	2031	23,984,265	7,143,474	10,625,917	51,783,970	93,537,626	62,964,852	156,502,477	194,611
27	2032	24,463,950	7,286,343	10,838,435	53,337,489	95,926,218	62,964,852	158,891,069	197,581
28	2033	24,953,229	7,432,070	11,055,204	54,937,614	98,378,117	62,964,852	161,342,969	200,630
29	2034	25,452,294	7,580,711	11,276,308	56,585,742	100,895,055	62,964,852	163,859,907	203,759
30	2035	25,961,340	7,732,325	11,501,834	58,283,315	103,478,814	62,964,852	166,443,666	206,972
31	2036	26,480,567	7,886,972	11,731,871	60,031,814	106,131,223	62,964,852	169,096,075	210,271
32	2037	27,010,178	8,044,711	11,966,508	61,832,768	108,854,166	62,964,852	171,819,018	213,657
33	2038	27,550,382	8,205,606	12,205,838	63,687,751	111,649,577	62,964,852	174,614,429	217,133
34	2039	28,101,389	8,369,718	12,449,955	65,598,384	114,519,446	62,964,852	177,484,298	220,701
35	2040	28,663,417	8,537,112	12,698,954	67,566,335	117,465,819	62,964,852	180,430,670	224,365
36	2041	29,236,685	8,707,854	12,952,933	69,593,326	120,490,799	62,964,852	183,455,650	228,127
37	2042	29,821,419	8,882,011	13,211,992	71,681,125	123,596,548	62,964,852	186,561,399	231,989
38	2043	30,417,847	9,059,652	13,476,232	73,831,559	126,785,290	62,964,852	189,750,142	235,954
39	2044	31,026,204	9,240,845	13,745,757	76,046,506	130,059,311	62,964,852	193,024,163	240,025
40	2045	31,646,728	9,425,662	14,020,672	78,327,901	133,420,963	62,964,852	196,385,814	244,205
41	2046	32,279,663	9,614,175	14,301,085	80,677,738	136,872,661	62,964,852	199,837,513	248,498
42	2047	32,925,256	9,806,458	14,587,107	83,098,070	140,416,892	62,964,852	203,381,743	252,905
	NPV	292,830,860	87,216,743	129,734,906	577,544,822	1,087,327,331	958,611,110	2,045,938,442	60,574
(% of NPV)		14.3%	4.3%	6.3%	28.2%	53.1%	46.9%	100.0%	

Appendix F Attendance at Coal Conferences

2004 Gasification Technologies Council Conference attended by Basin Electric

Basin Electric personnel attended the Gasification Technologies Council (GTC) Conference in October, 2004, in Washington D.C. This is the annual worldwide conference of the gasification industry. The Gasification GTC was created in 1995 to promote a better understanding of the role Gasification can play in providing the power, chemical and refining industries with economically competitive technology options to produce electricity, fuels and chemicals in an environmentally superior manner. The Council represents companies involved in the development and licensing of Gasification technologies as well as engineering, construction, manufacture of equipment and production of synthesis gas by Gasification from coal, petroleum coke, heavy oils, and other carbon-containing materials.

2004 PowerGen Conference attended by Basin Electric and CH2M HILL

Basin Electric and CH2M HILL personnel attended the PowerGen Conference in November, 2004, in Orlando, Florida. This is the annual worldwide conference of the power generation industry. The conference included a session on IGCC technology as well as other sessions on technical, environmental and commercial aspects of fossil fuel power technology.

Other conferences attended by Basin Electric

Basin Electric attended the Platts IGCC Symposium on June 2-3, 2005 in Pittsburgh, PA. This conference examined IGCC technology risk, costs, financing, environmental performance, and its future in the power industry. The following points were made at the conference concerning the cost competitiveness of the IGCC technology:

- GE stated that IGCC is still approximately 15 - 20% higher capital cost than a PC unit.
- Bechtel noted the heat rate can increase by 10 - 20% (lower plant efficiency) with low rank coals.
- ConocoPhillips stated the cost of electricity (COE) and capital costs increase rapidly (i.e. by 15 - 25%) with low rank fuels.

Appendix G Information Received from IGCC Technology Suppliers

Suppliers for IGCC technology were contacted to determine the status of their technology development and availability of a commercial offering. The vendors contacted included the primary technology suppliers for the demonstration IGCC plants and developers of alternative technologies located in or marketing their technology in the U.S.

Shell Global Solutions

Shell Global Solutions licenses the Shell Coal Gasification Process (SCGP). The Shell gasifier was used in the Buggenum IGCC demonstration plant in The Netherlands, and is similar to the dry feed Prenflo gasifier design supplied by Uhde for the Puertollano IGCC demonstration plant in Spain. The Shell and Prenflo gasifier technologies have now been combined and offered as the SCGP.

Basin Electric and CH2M HILL had extensive discussions with Shell and Uhde in November and December 2004 concerning the applicability of the SCGP to the Basin Electric NE Wyoming Project. Topics discussed included Shell gasifier experience with low rank coals, commercial operating experience, availability/reliability, plant altitude effect, process performance and design, capital and operating cost, emission rates, project guarantees and commercial issues. Shell prepared a brief study presentation for the Basin Electric NE Wyoming project that included a preliminary heat balance, approximate emission rates, and rough order of magnitude capital and operating costs.

General Electric

General Electric was contacted in January 2005 concerning the applicability of their IGCC technology to the Basin Electric NE Wyoming project, and their interest in receiving an RFP to provide an IGCC Feasibility Study for the project. General Electric licenses the ChevronTexaco coal gasification process. GE stated that they were interested in Basin Electric's project, but that it may be a tough or borderline application for their technology from a capital cost point of view for the following reasons:

- The use of PRB coal is not a technology issue, however, it increases the capital cost of the plant due to its high moisture content. Their IGCC cost would be more competitive if Basin Electric blended the PRB coal with petroleum coke purchased from refineries in the region.
- The 4,500 ft. elevation for the project site will cause the gas turbine power output to be derated by approximately 15%. The IGCC technology would be more competitive if the plant site was closer to sea level.
- The GE and Bechtel consortium has been focusing on a standard 600 MW power plant design that can be fully wrapped in a commercial offering.

GE stated that an IGCC plant would be significantly more expensive compared to a PC unit for Basin's project. GE currently has a project to reduce the capital cost of their IGCC technology to make it more competitive with PC units.

ConocoPhillips

ConocoPhillips was contacted in January 2005, and they stated their interest in receiving the RFP to provide an IGCC Feasibility Study for the project. ConocoPhillips licenses the E-Gas coal gasification process.

Process Energy Solutions

Process Energy Solutions (PES) was contacted about the status of their IGCC work and interest in receiving an RFP for an IGCC Feasibility Study. PES is a gasification consulting firm and project developer. They were interested in receiving the Basin Electric RFP for an IGCC Feasibility Study based on PRB coal. They stated that the dry fed gasifiers are most applicable to PRB coal since slurry fed gasifiers based on PRB Coal would result in approximately 50 wt. percent water in the slurry feed, which significantly decreases plant efficiency.

Future Energy

Contact attempts with Future Energy in Dortmund, Germany, prior to issuing the IGCC Feasibility Study RFP were unsuccessful due to the international travel schedule of key company personnel.

Gas Technology Institute

Gas Technology Institute (GTI) was contacted about the status of their U-Gas process and interest in receiving the RFP for an IGCC Feasibility Study. GTI, located in Chicago, Illinois, is a Not-For-Profit Research & Development company primarily involved in contract R&D in the energy and environmental fields. They are one of the major R&D players in the gas industry. Approximately one-third of their work is for the gas industry, one-third for the government (primarily DOE), and one-third for private industry.

GTI has a 1,000 Lb/Hr U-Gas pilot plant facility near Chicago, and a larger (15 MWth) high pressure pilot plant facility in Finland that includes a full hot gas cleanup system for sulfur removal. They have also furnished 8 commercial air-blown U-Gas gasifiers to a plant in Shanghai, China, to produce low heating value fuel gas. The total plant feed rate is 1,000 TPD of coal. The plant was started up in 1995; however, it is not currently operating. GTI does not have any commercial IGCC installations yet based on the U-Gas gasifier.

GTI's goal is to develop the U-Gas Coal Gasification Process and to turn it over to someone else to commercialize. The U-Gas process is available from GTI on a site license basis. They would have to team with another company to be able to provide a commercial offering. They can't make guarantees since they are a not-for-profit organization. GTI was interested in receiving the RFP, however, stated they would have to find a teaming partner to perform the IGCC feasibility study.

Boeing

Boeing was contacted about the status of their slagging gasifier development work and their interest in receiving an RFP for an IGCC Feasibility Study. Boeing responded that they were not far enough along in development of their gasifier to be able to bid on the Feasibility Study and put together a commercial offering. They are currently pursuing development of a pilot plant, tentatively to be installed and operated at GTI in Chicago, IL. They are also preparing for the next round of solicitations for the DOE Clean Coal Program in 2006. Their goal is to develop a 3,000 TPD gasifier that is 4 ft. diameter and 7 to 10 ft. long based on rocket engine technology.

Appendix H RFP and Proposals for IGCC Feasibility Study

Request for Proposals for IGCC Feasibility Study

Basin Electric decided to solicit proposals for an IGCC Feasibility Study for the NE Wyoming Project in early January, 2005. Request for Proposal (RFP) documents were prepared by Basin Electric and their Engineers/Consultants. The RFP included background on the project, coal analyses, site drawing, project schedule, scope of work, and study schedule. The feasibility study scope of work included project definition, initial EPC term sheet, design basis, emission rates, budget cost estimate, and project schedule.

The RFP was sent to the following six firms:

- Black & Veatch (consortium with Uhde to offer Shell process in the U.S.)
- ConocoPhillips (consortium with Fluor to offer E-Gas process)
- GE Energy (consortium with Bechtel to offer ChevronTexaco process)
- Process Energy Solutions
- Gas Technology Institute
- Future Energy GmbH

Evaluation of Proposals

The following responses were received to the RFP:

- Black & Veatch (B&V) provided a proposal to Basin Electric only based on Shell IGCC technology (would not allow BEPC's Engineers/Consultants to review the proposal without a confidentiality agreement)
- Fluor provided a proposal based on ConocoPhillips IGCC technology
- GE Energy provided a letter response without a proposal
- Process Energy Solutions (PES) teamed with Parsons to provide a proposal based on the Future Energy IGCC technology
- Gas Technology Institute declined to bid
- Future Energy GmbH declined to bid directly (offered technology through PES/Parsons proposal listed above).

Therefore, only three priced proposals were received by Basin Electric from B&V, ConocoPhillips and PES/Parsons. Basin Electric's Engineers/Consultants evaluated the ConocoPhillips and PES/Parsons proposals only, since the B&V proposal was only provided to Basin Electric. The results of the technical bid comparison are shown in Table 2 for the ConocoPhillips and PES/Parsons proposals. The Black & Veatch proposal is not included in the technical bid comparison because it was confidential.

Based on an evaluation of the proposals received, Basin Electric determined that the response to critical commercial aspects in the RFP was incomplete, and the cost to provide the study was greater than expected. In addition, Basin Electric expected the requested information would be readily available given the development of IGCC technology. Therefore, BEPC decided to continue its review of IGCC technology using Basin Electric's experience and that of their Engineers/Consultants.

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TABLE 2
Technical Bid Comparison - Proposals for Basin Electric NE Wyoming IGCC Feasibility Study
Basin Electric Dry Fork Station Technology Evaluation

Criteria	Process Energy Solutions	Fluor
Contractor	Developer: **Process Energy Solutions (PES)**	Engineering Firm: **Fluor Enterprises**
Subcontractors	Gasification Technology Provider: **Future Energy GmbH (GSP Schwarze-Pumpe tech.)**	Gasification Technology Provider: **ConocoPhillips (E-Gas technology)**
	Engineering Firm: **Parsons E&C**	
Organization Chart / Resumes	Provided with proposal.	Organization charts and bios (profiles) provided with proposal.
Gasification Technology	Dry feed, entrained-bed, slagging gasifier	Slurry feed, entrained bed, slagging gasifier
Experience	**PES**: Five persons with extensive coal gasification/IGCC experience at ChevronTexaco.	**Fluor**: More than 150 technical and economic evaluations for IGCC projects. EPC services on 20 major IGCC projects.
	Future Energy: 130 MW (thermal) GSP Schwarze-Pumpe gasifier producing methanol and power from lignite coal in Germany from 1984 to 1989.	**ConocoPhillips**: 2,400 TPD (160 MW thermal) Louisiana Gasification Technology, Inc. (LGTI) gasification facility operating from 1987 through 1995 on sub-bituminous coal producing syngas and steam. 262 MW Wabash River IGCC facility operating since 1995.
	Parsons: 95 MMSCFD Exxon Syngas Project, 235 MW Delaware City Refinery IGCC Repowering Project, LG-Caltex Yosu Refinery IGCC Feasibility Study, and ChevronTexaco Pascagoula Refinery IGCC Feasibility Study.	**Fluor / ConocoPhillips Alliance**: Detailed feasibility study for three train coke-fed IGCC plant for Citgo Lake Charles Refinery. Feasibility Study for Excelsior Energy Mesaba Energy 530 MW IGCC Project, and Feasibility Study for Madison Power Steelhead Energy SICEC 10,000 TPD facility to produce power and SNG.
References	**PES**: Consulting to TECO Polk Power IGCC, Developed Farmland Coffeyville Plant, 2 others.	**Fluor**: Front-end engineering design activities for relocation of 1000 TPD ammonia plant to Dakota Gasification Plant in Beulah, ND.
	Future Energy: Design and construction of 130 MW GSP Plant in 1984.	**ConocoPhillips**: Feasibility Study for Excelsior Energy Mesaba Energy 530 MW IGCC Project, and Feasibility Study for Madison Power Steelhead Energy SICEC 10,000 TPD facility to produce power and SNG.
Meets 11 Week Study Schedule in RFP?	Yes	No. Proposes 11 week schedule for submittal of draft report, with total schedule of 13 weeks for final report.
Scope of Work (Task Lead / Matches RFP SOW?)		
Task 1 – Study Design Basis	**PES**: Yes	Yes
Task 2 – PFD and Heat & Material Balances	**Future Energy**: Yes.	Yes
Task 3 – Plant and System	**Parsons**: Yes. P&IDs, motor lists and electrical	Yes. P&IDs, motor lists and electrical one line diagrams will not be

TABLE 2
Technical Bid Comparison - Proposals for Basin Electric NE Wyoming IGCC Feasibility Study
Basin Electric Dry Fork Station Technology Evaluation

Criteria	Process Energy Solutions	Fluor
Description	one line diagrams may be provided, if needed.	provided.
Task 4 – GA Site Plan and Elevations	**Parsons:** Yes	Yes. Selected elevations based on Wabash River plant design.
Task 5 – IGCC Air Emissions	**Parsons:** Yes	No. Air emissions provided for steady state operation at average ambient conditions only, based on in-house data. Preliminary emission values for facility flare and vent gas incinerator based on Wabash River design and experience.
Task 6 – Capital and Operating Cost Estimates	**Parsons:** Yes	Yes. Will also provide a preliminary major maintenance schedule defining major equipment outages for gasification island and combustion turbines, and a qualitative analysis of expected O&M costs during first year of operation.
Task 7 – Project Risk Assessment	**PES:** Yes	Yes. Estimate risk assessment (Monte Carlo type risk analysis), Event-Driven Risk Analysis and Availability Analysis will be provided.
Task 8 – Project Guarantees	**PES:** No information submitted. Proposal states "A project guarantee package will be developed with the best mix of cost and risk for BEPC."	No. Proposal states "Fluor and ConocoPhillips are prepared to negotiate summary terms for the NE Wyoming Project. Target guarantee levels will be developed during the Feasibility Study."
Task 9 - Schedule	**PES:** Yes	Yes
List of Deliverables	Matches RFP list of deliverables.	Matches RFP list of deliverables.
Gasification Tests	Recommend optional 10 kg sample of design coal for bench scale testing in Germany to confirm coal properties (additional cost). Optional Process Design Package gasification test in 5 MW (thermal) pilot plant in Germany after completion of feasibility study (requires 45 tons of design coal)	Proposal states "A coal gasification test is not typically required as part of a feasibility study. If required by Basin Electric, it may be possible to run a test of Basin Electric's design coal at the Wabash River plant; however, the scope and cost of such a test would need to be developed in concert with the owners of the plant."

Note: Black & Veatch Proposal was not included in this technical bid comparison because it was confidential

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