

A Comparison of PC, CFB and IGCC Technologies for Basin Electric Power Cooperative's Dry Fork Station

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DATE: June 26, 2007

This technical memorandum provides our response to some of the key issues addressed by the National Park Service and the environmental groups on the draft air permit for the pulverized coal (PC) unit proposed for the Dry Fork Station.

1. WYDEQ is not required to consider IGCC in the BACT analysis for Dry Fork

Step 1 of the Best Available Control Technology (BACT) analysis involves identifying all potentially applicable emission control options. However, it does not require the project sponsor to redefine the design of the source. Redefining the design of the source relates to meeting the purpose and need for the project, and/or in changing the fundamental constituents of the project's design.

The BACT process is set up to identify the emission control technologies available to reduce emissions from the source as defined by the applicant. The BACT process, coupled with PSD increment and ambient air quality modeling, will ensure that emissions from the proposed facility will be minimized and that the proposed facility will not cause or contribute to any violation of an ambient air quality standard.

1.1 IGCC would constitute a fundamental redefinition of the Dry Fork Plant

Integrated Gasification Combined Cycle (IGCC) is a fundamentally different process and design than a PC or circulating fluidized bed (CFB) boiler. In PC and CFB boilers, the fuel is coal, which is combusted. In IGCC, the coal is not the fuel. It is a chemical feedstock used in a series of chemical reactions called gasification. In gasification, the coal is not combusted, but is thermally converted in a series of chemical reactions, to create a synthetic gas, or syngas, which is the fuel for a separate combustion turbine power plant. An IGCC plant is more akin to a chemical plant, and has little in common with the combustion, steam generation and air pollution control (APC) systems utilized in PC and CFB boilers.

Pulverized Coal Process

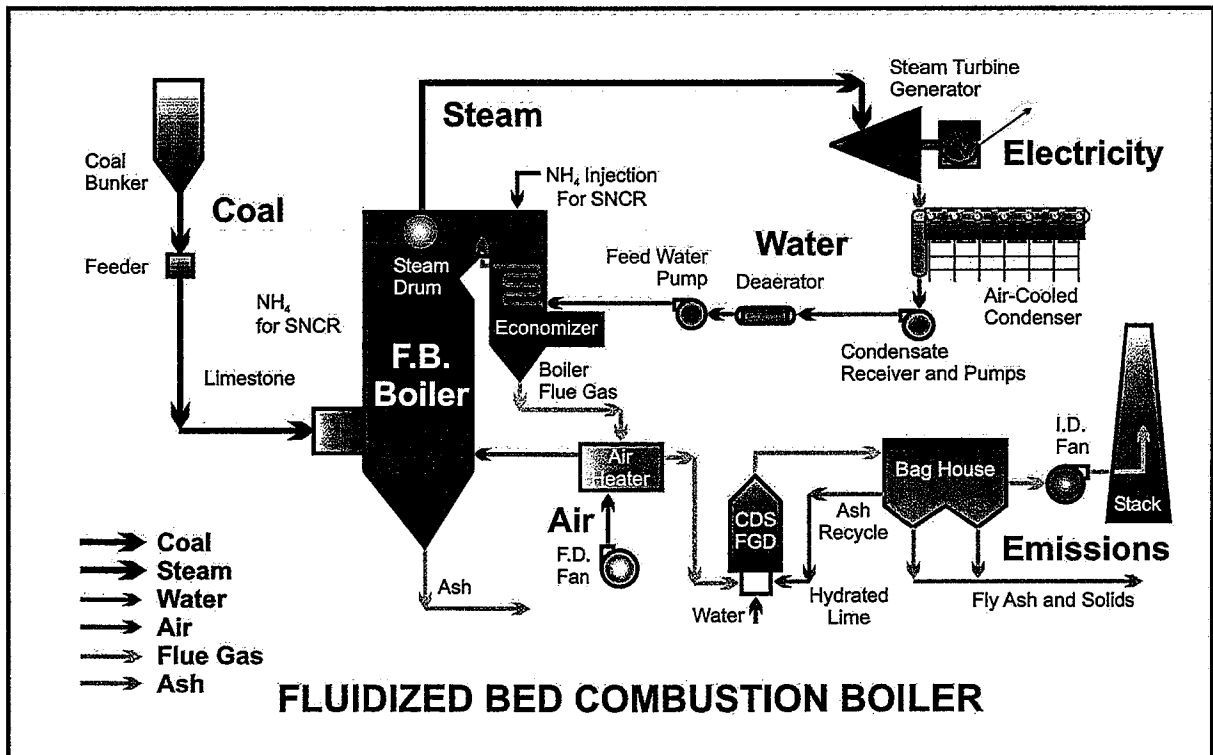
PC plants represent the most mature of coal-based power generation technologies considered in this assessment. Modern PC plants generally range in size from 80 MW to 1,300 MW and can be designed to use coal from various sources. Units operate at close to atmospheric pressure, simplifying the passage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

Desulfurization (FGD) system for removal of SO₂. Limestone is required as the reagent for the most common wet FGD process. 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 compared to wet FGD systems. A lime or limestone storage and handling system is required in the design of FGD systems. Depending on the type of FGD system used, the byproduct may or may not be commercially saleable. If not, sufficient storage area on site must be included in the plant design.

Circulating Fluidized Bed Process

The CFB fuel delivery system is similar to that of a PC unit, but somewhat simplified to combust a coarser material which is more difficult to burn completely. 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 with excess air to produce steam in the boiler tubes. Steam is piped to the steam turbine generator, which converts the steam's thermal energy into mechanical energy. The steam turbine then drives the generator to produce electricity. A typical process flow diagram for a CFB unit is shown in Figure 2.

FIGURE 2
Circulating Fluid Bed Unit Process Flow Diagram



CFB combustion temperatures of 1,500 to 1,600°F are significantly lower than a PC boiler, which results in lower NO_x emissions and reduction of slagging and fouling concerns that are characteristic of PC units. In contrast to a PC unit, SO₂ can be partially removed during

the combustion process by adding limestone to the fluidized bed. This is because the reaction of sulfur dioxide (SO₂) with limestone (calcium carbonate) peaks at about 1,500 °F, which is in the range of CFB boiler combustion.

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 throughout the boiler, 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.

One of the main advantages of CFBs is that they have the ability to efficiently combust a wide range of low quality fuels. CFBs are often recommended for low grade, high ash coals which are difficult to pulverize, and which may have variable combustion characteristics. CFBs are also suitable for co-firing coal with low grade fuels, including some waste materials, as well as petroleum coke, which has low volatile matter content. 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.

CFB 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 fouling.

The CFB produces combustion gases, which must be treated before exiting the exhaust stack to remove fly ash and SO₂. 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 emission control equipment external to the CFB includes either a fabric filter (baghouse) or ESP for particulate control (fly ash). A polishing FGD system is often required for additional removal of SO₂ to achieve similar emission levels to PC units with FGD systems. Limestone is required as the reagent for the most common wet FGD process, 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 is required if a lime spray dryer is used for the polishing FGD system. Due to the method of SO₂ control, the byproduct is not typically commercially saleable. Therefore, sufficient byproduct storage area must be planned for the CFB unit.

IGCC Process

The gasification portion of an IGCC plant for use in coal-based power generation combines a chemical feedstock, coal, with steam and oxygen or air at high temperature and pressure to produce a gaseous mixture consisting primarily of hydrogen and carbon monoxide. This gaseous mixture, called syngas, is the result of a thermal conversion process, and not combustion. Where PC and CFB boilers use excess air to assure combustion, gasification

occurs in an "oxygen-starved" environment, in order to assure that combustion is precluded. Where the product of combustion in a PC or CFB is hot flue gas that, after transferring its heat to boiler tubes, has no further use and must be exhausted through a stack, the product of gasification is a usable syngas, the intermediate step in providing a fuel for power generation in a combustion turbine, or for the production of chemicals. Where PC and CFB boilers are based on the Rankine thermodynamic cycle (steam production and use in a steam turbine), IGCC uses the Brayton cycle, based on firing a fuel, syngas, in a rotating combustion turbine. These two thermodynamic cycles are completely different.

The syngas requires cooling and cleanup to remove contaminants to produce a synthesis gas (syngas) 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 natural gas-fired combined cycle plant. The most significant differences in the combined cycle are modifications to the combustion turbine to allow use of a low heating value, 250 Btu/scf syngas (about 1/4th that of natural gas), which is then mixed with nitrogen for NO_x reduction, resulting in a heating value of about 125 Btu/scf. The nitrogen is added in order to cool the flame and lower NO_x emissions, as well as providing additional mass flow in the combustion turbine to boost power output. The fuel mixing system and burners for combusting syngas (CO and H₂) are very different than those used for burning natural gas (methane). Combustion turbines designed for natural gas firing utilize a dry low NO_x burner design, which has been optimized for burning methane at a heating value of about 1,000 Btu/scf. However, syngas combusts very differently, since it contains a high concentration of hydrogen. Combustion of syngas requires a diffusion burner design, which accounts for the lower heating value of the syngas and higher flame speeds of hydrogen. It also allows for the injection of nitrogen for cooling the flame and reducing the production of NO_x. While natural gas can be used as a supplemental fuel in syngas combustion turbines, it does not combust as efficiently as in combustion turbine designed for natural gas use as the primary fuel.

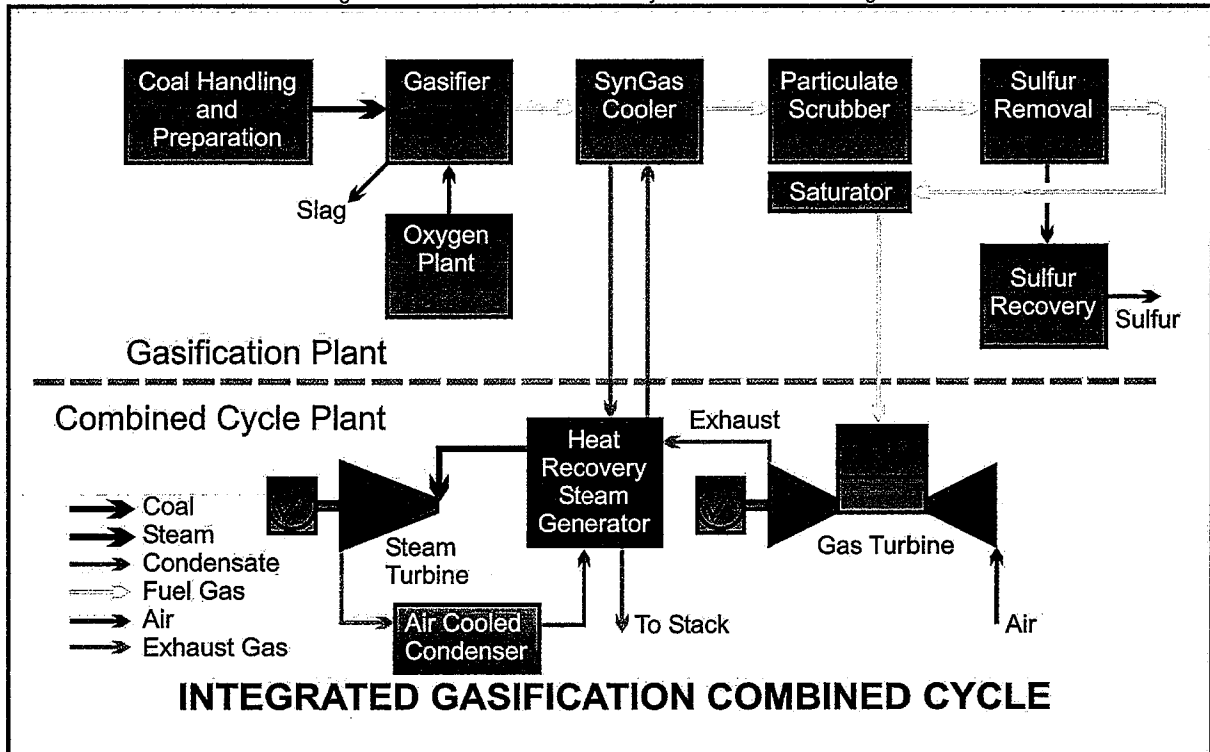
In addition, the steam turbine portion of an IGCC unit is much larger than that of a natural gas-fired combined cycle unit, since a majority of the steam production in IGCC comes from the syngas coolers in the gasification portion of the plant, versus all of it being produced in the heat recovery steam generator (HRSG) in a gas-fired combined cycle plant. 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 syngas. A typical process flow diagram for an IGCC unit is shown in Figure 3.

Coal gasification takes place in the presence of a controlled "shortage" of air/oxygen, thus producing reducing conditions, whereas combustion of coal in a PC or CFB creates an oxidizing environment. The process is carried out in an enclosed pressurized reactor, and the syngas product is a mixture of CO, H₂ and CO₂. Prior to use, the syngas must be cleaned. It is important to note here that in gasification it is not the coal that is cleaned. Rather, it is the syngas, the product of gasification reactions, which is cleaned so that it can be used as a fuel in a separate process.

The sulfur present in the feedstock mainly forms hydrogen sulfide (H₂S) but there is also a small amount of carbonyl sulfide (COS). The H₂S can be more readily removed than COS in syngas-cleanup processes; therefore, a hydrolysis process is typically used to convert COS to H₂S. The syngas is cleaned and then burned with air in the combustion turbine, generating combustion products at high temperature and pressure. Although no NO_x is formed during

gasification, some is formed when the syngas is subsequently burned in the combustion turbines.

FIGURE 3
Integrated Gasification Combined Cycle Process Flow Diagram



Three basic gasifier designs are used: fixed beds (not normally used for power generation), fluidized beds and entrained flow gasifiers. 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 or dry feed, depending on the gasification technology supplier. Oxygen-blown, entrained-flow gasifiers are used in modern IGCC plants, although several new technologies under development plan to use air as the oxidant.

In PC and CFB, the moisture must be removed from the coal for combustion to occur efficiently. In coal gasification, moisture is an important part of the coal feedstock. Without water, the chemical reaction that is the basis of gasification cannot occur. That is why low moisture coal must be ground up and made into a slurry, and then pumped into the gasifier. Some gasification technologies use a dry coal feed, usually for high moisture coals, i.e. subbituminous and lignite. The coal is milled and dried, and then fed with nitrogen into the gasifier. If there is not sufficient inherent moisture left in the coal to provide the needed water for gasification reactions, steam can be injected into the gasifier.

The coal-based IGCC plants that are in operation use different process designs, and are demonstrating the practicalities and economics of different degrees of integration. The syngas is produced at temperatures up to 2,900°F (in entrained flow gasifiers), so that the syngas must be cooled sufficiently to utilize conventional acid gas removal systems (for removal of sulfur compounds), which operate at about 100°F. The acid gas cleaning

processes used are variants of well proven natural gas sweetening processes to remove acid impurities and any sulfur compounds present.

Large radiant and convective heat exchangers are required to accomplish this reduction in syngas temperature; in doing so, a large amount of high pressure steam is produced, which is used in the combined cycle portion of the plant for power generation. In the heat exchangers, solids deposition, fouling and corrosion may take place. This has been a significant cause of low availability at Tampa Electric Company's (TECO) Polk Power Station. The plant must be brought down every few months just to clean out the convective syngas coolers.

Conclusion

EPA's NSR Manual states clearly that a proponent of a coal-fired power plant is not required to consider converting its proposed plant to a natural gas-fired turbine as part of a BACT analysis, because that would be redefining the design of source. Where PC and CFB combust coal to produce steam and electricity using the Rankine thermodynamic cycle, an IGCC plant generates electricity by means of converting coal to a syngas in a chemical reaction and burning it in a combustion turbine using the Brayton thermodynamic cycle, like a natural gas-fired combustion turbine. Clearly, changing from the Rankine thermodynamic cycle of PC and CFB to the Brayton cycle of IGCC would be redefining the fundamental design of the source.

1.2 Purpose and Need for Project

BEPC desires to identify the most prudent power generation technology for this new coal-fired power plant. That identification process is guided by these requirements for the proposed generating unit:

- Providing Base Load Capacity with High Reliability and Availability
- Assuring Environmental Compliance
- Utilizing Commercially Available and Proven Technology
- Generating Electricity at a Reasonable Cost

Coal-based power generation technology selected for this project must be capable of meeting all of the desired characteristics listed above to meet the purpose and need for the project.

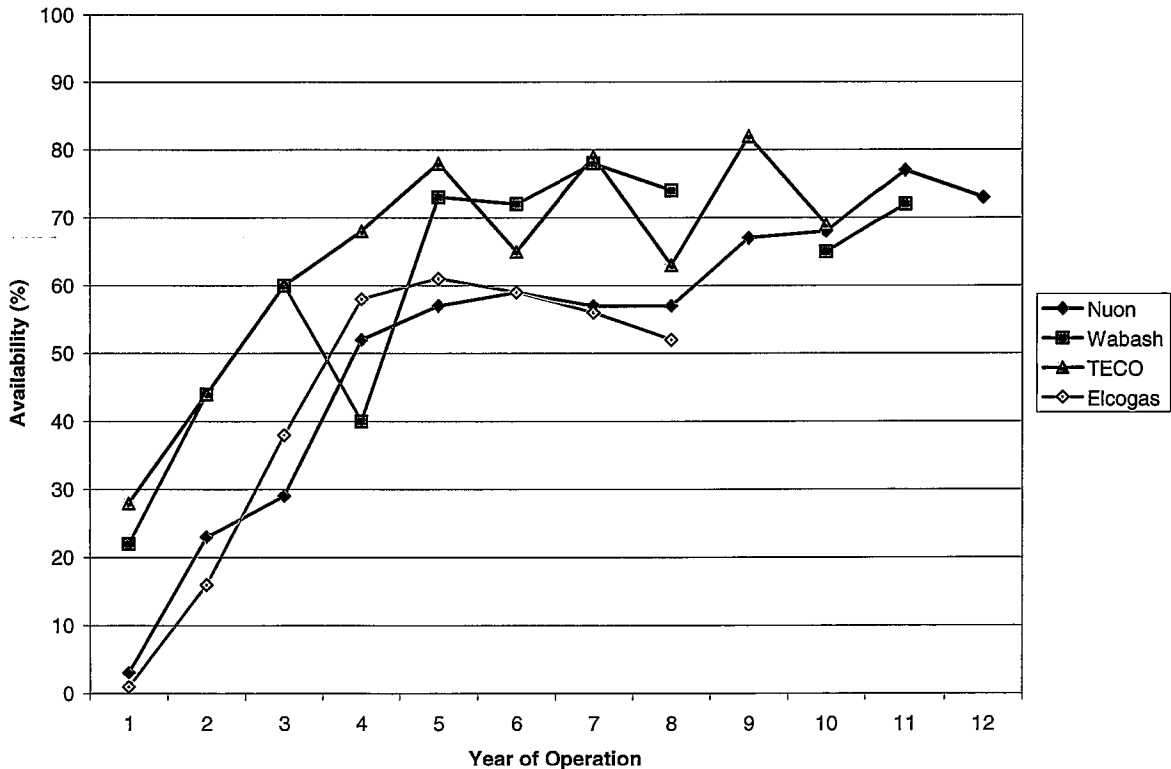
Providing Base Load Capacity with High Reliability and Availability

Basin Electric requires the Dry Fork Station to be a base load plant with high reliability and availability. This relates directly to the ability of the power generation station to provide the electricity to the Basin Electric customers when they need it. If the Dry Fork plant is not reliable, and has low availability, its generation must be made up by other sources of power generation, if available; these are likely to be less efficient, more costly sources of generation. Both PC and CFB technologies are technically and commercially mature and are used for baseload power plants. The overall plant availability of well-designed and maintained base load PC and CFB units is over 90 percent. A good example of the high availability of PC units is BEPC's own Laramie River Station. Over the last six years, the availability of the three PC units at that plant has been 91.4%. During some years, units achieved as high as 99.4%. This underscores the performance of this well-proven technology for meeting the

high availability required for BEPC's customers. PC technology has been developed to provide high availability, as can be counted on to do so on a consistent basis.

In contrast, all four of the coal-based IGCC plants worldwide 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 much lower than what they were designed for, as well as being far lower than what can be achieved with PC and CFB technology. The reported annual availabilities for commercial coal-based IGCC plants versus year of operation are shown in Figure 4 (values are for coal-based IGCC operation, without use of back-up fuel). There is a gap in the Wabash plant curve data because the unit was shut down for a period of time for economic reasons. None of the units have achieved their design targets of 85% availability. Only one, Polk Power Station, reached 80%, but this did not occur until its ninth year of operation, and it has not maintained this level of availability. What this means is that more than 20% of the time (for the Polk unit, and much more frequently for the others), these IGCC plants were not available for their intended purpose and need, and other less efficient, higher cost generating resources had to make up for their low availability. Availability of 90% or better is needed for the Dry Fork project, and this historical data shows that IGCC is not yet capable of meeting that requirement.

FIGURE 4
Coal Based IGCC Availability



It is important to note that IGCC plants often report their availability data in the IGCC mode of operation, as well as for the power block only when it is operated on the back-up

fuel. Operation on the back-up fuel can occur during start-up and shutdown, when the gasification island is down for a short period of time and can be re-started quickly, and when the plant's generating capacity is required. While such operation can help to boost plant availability, it is not the overall IGCC plant which is providing the higher availability. This essentially masks the fact that the IGCC plant has a low availability, meaning that the gasification portion of the plant, which is typically 2/3 of the entire IGCC plant cost, is not performing well and is an under-utilized asset. This in itself reduces the cost-effectiveness of the technology, as the high fixed costs of the gasification portion of the plant must be spread over fewer kilowatt-hours of generation. Such operation is not as a least-cost resource.

In addition, operation of the power block only using the back-up fuel increases the cost of electricity production significantly, due to the fact that both natural gas and fuel oil (which may be used as a back-up fuel, depending on combustion turbine design) are significantly higher in cost than the coal and/or pet coke used as the primary feedstock to the gasifier. In addition, operation on the back-up fuel may raise the cost of generation to a point where the plant is not dispatched as a base load unit at all.

A key example of this is the Piñon Pine IGCC project, which is not even noted in the availability graph. This was the third coal-based IGCC plant planned for construction and operation under the DOE Clean Coal Technology Program. Unfortunately, this technology and the project failed due to problems with the basic design and performance of the gasifier, as well with the syngas cleanup system. It was never able to maintain consistent operation on syngas, and was shut down and abandoned. The gas turbine remained in operation using natural gas as a primary fuel. This further highlights that IGCC is not yet a commercially proven technology for power generation.

A major reason for low IGCC plant availability is that the existing coal-based units have only one gasifier train, so that problems that require shutdown of a part of the gasifier train lead to a shutdown of the entire gasification island. IGCC units being designed today are using the many lessons learned from the Polk and Wabash River plants to improve overall IGCC plant availability. Primary design changes for improving availability include additional gasifier trains, i.e. two 50% sized trains, so that each gasifier produces sufficient syngas to fully load one combustion turbine. If one gasifier train becomes unavailable, the IGCC plant can at least stay on line at half load while the out-of-service train can be worked on and brought back on line.

The industry projects that operation with two 50% gasifier trains may be able to achieve 85% availability. While this new IGCC configuration is expected to provide for higher availability, it is not yet proven in commercial service and won't be until the first new IGCC plants start operation in another four to five years. In order to maintain full-load operation should one of the operating gasifier trains be removed from service, a third 50%-sized spare gasifier train could be added. This adds considerable capital cost to the IGCC project, as well as the continuous operating cost of natural gas or other gaseous fuel used to keep the spare gasifier at operating temperature at all times (it must be kept hot so that it can be brought into gasification service quickly). Even with a spare gasifier, it is not yet known if IGCC will be able to match the high availability of PC and CFB technologies. Only the Excelsior Energy Mesaba IGCC Project is planning to include a third 50%-sized train.

Whether or not this significant capital and operating expense that they will incur will result in significantly higher availability will not be known for another five years.

Assuring Environmental Compliance

A PC boiler combined with appropriate air pollution control (APC) technology offers similar emission rates to a CFB boiler for SO₂, NO_x, particulate matter, mercury and other hazardous air pollutants (HAPs). A PC plant with the latest proven APC technology provides lower SO₂ and NO_x emission rates when compared to the two U.S. coal-based IGCC plants at SG Solutions' Wabash River Generating Station and TECO's Polk Power Station.

Future IGCC plants have the potential of offering lower SO₂ 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 1 compares the proposed BACT Dry Fork Station PC emission rates with expected BACT CFB and IGCC emission rates.

The emission limits shown for the proposed IGCC plant are based on data from air permit applications from several proposed IGCC projects. These limits are based on preliminary designs. This emission performance has not yet been demonstrated in actual operation, and won't be for another four to five years until these proposed units begin operation. The MDEA sulfur removal technology system has been in use at the Polk and Wabash River plants for more than a decade. Due to design changes based on lessons learned at these two plants, a higher level of removal of sulfur compounds is expected for the proposed plants. However, as noted above, it is yet to be demonstrated.

TABLE 1
Comparison of Coal-based Power Generation Technology Potential BACT Emission Rates
Basin Electric Dry Fork Station Technology Evaluation

| Emission Rates for Coal-based Power Generation Technologies (Lb/MMBtu) | | | | |
|---|-----------------------------|-------------------------------|---|--|
| Pollutant | PC w/Dry FGD and SCR | CFB w/Dry FGD and SNCR | Proposed IGCC w/MDEA Sulfur Removal / No SCR | Existing IGCC (w/MDEA Sulfur Removal / No SCR)* |
| SO ₂ | 0.080 | 0.080 | 0.025 | 0.170 |
| NO _x | 0.050 | 0.090 | 0.057 | 0.076 |
| PM ₁₀ (filterable) | 0.012 | 0.012 | 0.0063 | 0.013 |
| CO | 0.150 | 0.150 | 0.036 | 0.035 |
| VOC | 0.0037 | 0.0037 | 0.001 | 0.0017 |

Notes:

* Wabash River Station and Polk Power Station Existing U.S. IGCC Demonstration Plants.

Utilizing Commercially Available and Proven Technology

PC technology is available commercially at sizes well over 1,000 MW, with a long history of being the global technology of choice for large base-load utility units. Current IGCC plants are providing good information about the technology and its performance. However, current and near-term IGCC plants must be viewed as using a technology which is still under development. IGCC technology is not yet able to provide cost-effective electricity or

the performance necessary to be available commercially in a time frame to support BEPC's needs.

Number and Quality of Suppliers

PC power plant technologies are offered commercially on a turnkey basis by some of the larger power generation technology suppliers. In addition, some engineering/boiler vendor/contractor consortia 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. It is standard practice in the electric utility industry to acquire a complete PC-based power plant under a turnkey Engineer, Procure and Construct (EPC) contract, which typically provides guarantees for cost, schedule, performance, heat rate, emissions, and output (gross and net). Such guarantees are critical for the utility to be able to finance the project and to provide assurance that the new unit will be built on schedule and on budget, will perform as designed, and will comply with all environmental permits.

With only two coal-based IGCC plants in the U.S., there is a lack of data for IGCC technology providers to fully understand the costs and performance of IGCC so that they could provide the same guarantees and warranties typical with PC plants. The reliability and performance of the technology is an important factor given that this plant is intended for base load generation and represents approximately 10 percent of BEPC's generating capacity portfolio. Going forward with an IGCC plant (or actually any type of new plant) without such guarantees and warranties would subject BEPC to substantial technical and financial risk, and put the reliability of BEPC's system at risk.

After the electric utility industry called on the IGCC technology providers to provide such a suite of guarantees, the suppliers responded and stated that they were ready to do so. A GE/Bechtel alliance is developing a 600 MW "reference plant" design based on the GE entrained bed gasifier using eastern bituminous coal. A ConocoPhillips/Fluor/Siemens alliance has also offered their 600 MW reference plant based on the E-Gas entrained bed gasifier with eastern bituminous coal. Both alliances have publicly stated that they plan to offer turnkey systems based on these standard plant designs. Shell has an alliance with Black & Veatch and Uhde, but with no specific power block supplier.

While these alliances have stated that they are ready to provide the guarantees noted above, this has not happened to date. A good example of what the IGCC industry is/is not able to offer is highlighted in the recent regulatory submittal by Duke Energy Indiana with the Indiana Utility Regulatory Commission (IURC). Duke Energy Indiana is planning a 630 MW (net) IGCC plant to be installed at its existing Edwardsport Plant in Indiana, using eastern bituminous coal. As part of the filing, Duke was required to submit its complete Front End Engineering and Design (FEED) package, as well as the cost estimate that the GE/Bechtel team created as part of their work. When the first cost estimate was completed in early January 2007, Duke found the cost to be much higher than they had anticipated, and instructed the GE/Bechtel team to re-work the design to reduce the cost and increase the performance. Following those efforts, Duke filed its FEED information with the IURC. The cost that Duke submitted for this IGCC plant, based on eastern bituminous coal, was \$1.985 billion, or \$3,150/kW. This is about 35% more than the capital cost of a PC unit.

It was clearly Duke's expectation that it would be able to receive appropriate guarantees and warranties as part of the contract with the GE/Bechtel team. However, either the GE/Bechtel team was unwilling or unable to provide them, or the cost was too high on top of the already \$1.985 billion price tag. As Duke stated in their submittal, "A lump sum turnkey contract approach is not the best option or even a viable option." Duke will manage the entire project internally, using use a blend of cost reimbursable, target cost and lump sum pricing. They will need to obtain guarantees on the individual systems or pieces of equipment, although there will not be an overall EPC guarantee, as is available with PC technology. This results in additional technical and financial risk that Duke must take on.

Following that, American Electric Power (AEP) delayed its planned IGCC plant in Ohio, from 2011 to 2015. This was primarily due to cost reasons (and likely with the same guarantee and warranty issues encountered on the completion of their GE/Bechtel FEED study and cost estimate), and the risk of not being able to recover its costs in Ohio, which is not a regulated state.

In June, 2007, Tondu Corporation announced that it was canceling its proposed 600 MW IGCC plant in Corpus Christi, Texas, due to high cost. Tondu also stated that "Developers of the coal gasification technology are not willing to provide performance guarantees and none will build the systems."

While turnkey supply of IGCC technology may eventually become available, it may also come at a high cost, and will likely only be offered for plants using the 600 MW net reference plant design with eastern bituminous coal. The IGCC suppliers are standardizing on the 600 MW size, based on the use of eastern bituminous coal, as it utilizes two gasifiers to provide sufficient syngas to fully load two "F class" combustion turbines. Smaller sizes or "odd" sizes that do not fully load a combustion turbine are not cost effective or commercially available at this time.

IGCC experience on PRB coal is very limited. The only coal-based gasification demonstration plant that operated with PRB coal was the Dow Chemical Louisiana Gasification Technology, Inc. (LGTI) plant in Plaquemine, LA. This plant used an oxygen-blown, entrained flow E-Gas gasifier, and operated successfully with subbituminous coal from 1987 to 1995. The syngas was burned in two Siemens combustion turbines, although the plant did not operate in an integrated, true IGCC configuration with an HRSG and a steam turbine. This facility was shut down when the demonstration program was completed in 1995. Much of its operational data was used in the design of the Wabash River IGCC plant.

Two 600 MW IGCC plants, based on the use of subbituminous PRB coal, are being planned. They include Excelsior Energy's Mesaba IGCC project in Minnesota (two 600 MW IGCC units), as well as Energy Northwest's proposed Pacific Mountain Energy Center in Washington State. Both plants will be designed to be able to use 100% PRB coal, as well as blends of PRB with pet coke or with other coals. These plants will not be in operation until 2011 at the earliest, with consistent, reliable operational data not likely to be available until 2013. Recently, Energy Northwest announced that it was delaying its IGCC plant, as it would not be able to comply with Washington State's new law requiring CO₂ capture and sequestration. Therefore, it is uncertain as to when, if ever, this plant would begin operation. Just as uncertain is whether it will use PRB coal as the primary feedstock, or if pet coke will

be selected. The Mesaba IGCC Project has faced some recent disapprovals in its siting and permitting process, due to the high capital cost of the plant and its resulting high projected cost of electricity. After more than a year into the state of Minnesota power plant certification process, it has not yet received its approvals, and it is uncertain when it might.

A third IGCC plant in development will be the 285 MW Orlando Gasification demonstration plant, to be developed near Orlando, Florida. It will demonstrate the KBR transport reactor gasification technology, using PRB coal. The facility received its final air permit in late 2006, and startup is planned for 2010-2011. However, this is only a demonstration-sized plant, and this technology is not yet commercially available. Due to significant increases in the projected cost of the plant, the project developers are working with the DOE to determine what the final cost may be and how the cost increases will be shared.

While the gasification of subbituminous coal has been demonstrated, it has only been at a relatively small scale. The cost, availability, and efficiency of IGCC designed for use with PRB coal is not yet known, nor will it be known for another five to six years. If one or more of the IGCC plants noted above do go forward, it will provide the industry with information on IGCC operation with PRB coal only with the 600 MW net reference plant configuration, at relatively low altitude. No IGCC technologies are commercially available on a turnkey basis for a 368 MW net IGCC plant based on PRB coal, with operation at high altitude.

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. 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. As described above, in lieu of providing an overall "wrap" on the IGCC plant, IGCC technology suppliers or alliances are likely to provide individual guarantees on emissions, gross and net output, and possibly availability, but only if packaged with a long-term service agreement, which is likely to have significant cost. Again, the nature of what the IGCC alliances are able to provide commercially is not yet known, as no utility or plant developer has signed a contract for a complete IGCC plant with such guarantees.

Need for Government Subsidies

Building PC and CFB plants is routine in the industry, because the technologies are well-known, are commercially available and proven, and the costs and performance are well-known on a wide range of coals. This is not the case with IGCC. Even large utilities are having difficulty in justifying IGCC reference plants based on using eastern bituminous coal. This is due to many factors, including:

- Historical low availability at IGCC projects, especially in early years of operation, resulting in substantially lower net present values (NPVs).
- Uncertain capital funding needs of IGCC projects.
- Continued, significant escalation in cost estimates for IGCC.
- Lack of guarantees for overall performance of the IGCC power units by plant designers, equipment suppliers and construction companies, or by the IGCC technology alliances.

The existing coal-based IGCC plants required significant government subsidies. Although they have been in operation as long as 12 years, these concerns have not changed. There is a continuing need to offset IGCC capital costs with government subsidies, loan guarantees, and/or tax credits. Almost all of the IGCC plants planned at this time are receiving direct co-funding or tax credits by their specific states or under the DOE's Clean Coal Power Initiative, have been awarded tax credits under the Energy Policy Act of 2005, or are applying for a loan guarantee under that Act.

Further cost recovery mechanisms are required to cover the high capital cost premium of IGC cover PC. On June 12, 2007, the governor of Florida signed a new law that would allow Tampa Electric Company to receive accelerated, up-front cost recovery on its proposed 630 MW IGCC reference plant, based on eastern bituminous coal. Without this special legislation, Tampa Electric would not be able to finance the project at reasonable rates. In effect, the law adds IGCC onto an existing law that provided for early cost recovery for high-cost nuclear plants.

Generating Electricity at a Reasonable Cost

The capital and operating costs of PC and CFB technologies are well-known, based on decades of operating experience. As noted above, this is not the case for IGCC. The IGCC industry is standardizing on the 600 MW IGCC reference plant, based on eastern bituminous coal, and there are several new sources of information that provide capital and operating costs for this configuration. Since several proposed IGCC units will be based on the use of Wyoming Powder River basin (PRB) subbituminous coal, or blends of PRB with other feedstocks, some additional cost information is becoming available (but only at the 600 MW size, and at low "eastern" elevations).

The Dry Fork Station project will be a nominal 368 MW (net) plant at an elevation of 4,250 feet with low heating value/low sulfur PRB coal feedstock. An IGCC plant for this project (although it is not in a commercially available size as explained above) 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 combustion turbines and combined cycle due to the high plant elevation. At high elevation, there is not sufficient air available for the combustion turbines, so that the syngas fuel feed must also be reduced, resulting in lower combustion turbine output. Further, this lower output results in less steam production for the steam turbine, reducing its output. Based upon available data, the 630 MW "reference plant" IGCC unit, using PRB coal at this elevation would have an output of only about 570 MW, further increasing the cost in \$/kW.

The issue of high capital cost for IGCC has become even more critical recently. In public presentations, IGCC technology providers stated that the capital cost of a 600 MW net IGCC reference plant designed for use with eastern bituminous coal would be about 25% greater than that of PC technology, with a goal of cutting that premium in half through innovative designs for the "Nth" plant. This would be projected to result in the COE from IGCC being on par with that of PC. However, recent cost data provided in public submittals and announcements has shown that this 25% premium is far low. The costs for an IGCC plant, using PRB at high altitude, is not yet known; however, due to the reasons described above, it will be much higher than for a plant designed for using eastern bituminous coal at low altitude. Recent public information on IGCC cost includes:

- **Duke Energy Indiana:** The cost estimate for the Edwardsport IGCC plant, based on eastern bituminous coal (filed with the Indiana Utility Regulatory Commission) in late 2011 dollars, is \$1.985 billion, or about \$3,150/kW. This is about 35% more than the cost of a PC unit.
- **Excelsior Energy:** A filing with the DOE during 2006, as part of receiving co-funding from the Clean Coal Power Initiative for the Mesaba IGCC Project, was \$ 2.156 billion, or approximately \$3,600/kW. This is about 35-40% more than the cost of a PC unit designed for wide range of feedstocks.
- **Tampa Electric Company:** A filing with the Florida Public Service Commission during April 2007, regarding their proposed Polk Power Station Unit #6 IGCC plant (based on eastern bituminous coal), listed a cost of \$3,180.30/kW in January 2013 dollars. This is about 35% more than the cost of a PC unit.
- **American Electric Power:** Testimony filed with the Public Service Commission of West Virginia in June 2007 provides a cost of the AEP Mountaineer IGCC plant of \$2.23 billion, or \$3,545/kW in 2012 dollars. This is about 35-40% greater than the cost of a PC plant designed for use with eastern bituminous coal.
- **Tondu Corporation:** Announced that it was canceling its proposed 600 MW Nueces IGCC plant in Corpus Christi, Texas, based on using pet coke, due to the high cost of the plant, and that they could not obtain performance guarantees.

The major economic criteria used for the cost evaluation of the PC, CFB, and IGCC and cases for the Dry Fork Station are listed in Table 2. Note that the IGCC values are based on achieving 85% availability with two 50%-sized gasifier trains, and natural gas to make up the additional operation to meet a 90% availability value. While PC and CFB technologies have clearly proven their ability to provide the required, consistent 90% availability performance, the historical data shown above shows that IGCC technology is not yet able to consistently meet even 80% availability. Although today's designs are projected to allow IGCC to eventually reach the 85% availability level, this is still uncertain, and it will not be known for another five to six years.

TABLE 2
Coal-based Power Plant Economic Evaluation Criteria
Basin Electric Dry Fork Station Technology Evaluation

| Criteria | CFB w/Dry FGD and SNCR | PC w/Dry FGD and SCR | Proposed IGCC w/MDEA Sulfur Removal / No SCR | Comments |
|-----------------------------------|------------------------|----------------------|--|----------------------------------|
| Net Plant Output (MW) | 368 MW | 368 MW | 368 MW | Annual Average |
| Net Plant Heat Rate (Btu/kWh) | 10,377 | 10,077 | 10,250 | Annual Average |
| Annual Plant Capacity Factor (%) | 90% Coal | 90% Coal | 5% Natural Gas, 85% Coal | Provide 90% "plant" availability |
| Interest Rate (%) | 6.0% | 6.0% | 6.0% | |
| Discount Rate (%) | 6.0% | 6.0% | 6.0% | |
| Capital Cost Recovery Period (Yr) | 42 years | 42 years | 42 years | |

TABLE 2
Coal-based Power Plant Economic Evaluation Criteria
Basin Electric Dry Fork Station Technology Evaluation

| Criteria | CFB w/Dry FGD and SNCR | PC w/Dry FGD and SCR | Proposed IGCC w/MDEA Sulfur Removal / No SCR | Comments |
|--|------------------------|----------------------|--|----------|
| Plant Economic Life (Yr) | 42 years | 42 years | 42 years | |
| Fixed O&M Cost (\$/kW-Yr) | 20.0 | 18.0 | 26.0 | |
| Non-Fuel Variable O&M Costs (\$/kWh) | 0.0040 | 0.0026 | 0.0060 | |
| Mine Mouth Coal Cost (\$/MMBtu) | 0.35 | 0.35 | 0.35 | |
| Natural Gas Cost (\$/MMBtu) | 7.50 | 7.50 | 7.50 | |
| Notes: | | | | |
| * Proposed IGCC plant based on two 50% capacity gasifier trains and natural gas backup fuel. | | | | |

It is also important to note that the use of natural gas as a backup fuel for IGCC requires that a natural gas pipeline be included in the design, permitting and construction of an IGCC plant. The pipeline must be capable of providing sufficient natural gas for use at full load by both combustion turbines. This is a significant additional capital cost which is not included in the economic analysis. It would further increase the cost spread between IGCC and PC, in both capital cost and operating costs (spreading even more capital costs over the number of megawatt-hours generated).

Economic Analysis Summary

The overnight capital costs and life cycle economic analysis for the PC, CFB, and IGCC cases are shown in Table 3. The NPV for the PC, CFB, and IGCC cases was calculated based on the 6.0 percent discount rate and annual cash flows for a plant economic life of 42 years.

The total first year cost for the PC case is \$113.6 million versus \$122.3 million for the CFB case. The NPV for the PC case is \$1.849 billion versus \$2.007 billion for the CFB case over the 42 year plant economic life. The cost for the IGCC case is much higher at \$164.4 million for the total first year cost, and \$2.777 billion for the NPV.

The largest life cycle cost driver for the three 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 all three technologies. Besides capital cost and annual debt service, another significant cost differential between the PC/CFB cases and the IGCC case is the natural gas usage.

TABLE 3
Economic Analysis Summary for Power Generation Technology Options
Basin Electric Dry Fork Station Technology Evaluation

| Costs | Cost (\$ Million) | | |
|--|--------------------|--------------------|---------------------|
| | CFB | PC | IGCC |
| CAPITAL COST | 1,404 | 1,350 | 1,755 |
| FIRST YEAR O&M COST | | | |
| Fixed O&M Cost | 7.5 | 6.8 | 9.8 |
| Non-Fuel Variable Cost | 11.8 | 7.7 | 17.8 |
| Coal Cost | 10.8 | 10.4 | 10.1 |
| Natural Gas Cost | <u>0</u> | <u>0</u> | <u>11.5</u> |
| TOTAL FIRST YEAR OPERATING COST | 30.1 | 24.9 | 49.1 |
| FIRST YEAR DEBT SERVICE | <u>92.2</u> | <u>88.7</u> | <u>115.3</u> |
| TOTAL FIRST YEAR COST | 122.3 | 113.6 | 164.4 |
| Net Present Value (NPV) | 2,007 | 1,849 | 2,777 |

Both PC and CFB are mature technologies that can meet the required 90% annual availability for the project. IGCC technology has not demonstrated even 80% availability on a consistent basis. Using two 50% sized gasifier trains is projected to provide for 85% availability, although it will be another 5-6 years before this configuration is proven in commercial service. Natural gas would be needed as a secondary fuel for the combustion turbines to make up the 5% annual availability difference to meet the required 90% annual availability for the project (although, as explained above, this would not be considered to be IGCC operation when the gasification portion of the plant is not available, and generation using natural gas would be significantly higher in cost).

A comparison of the first year busbar cost of electricity for the three technology cases is shown in Figure 5.

Conclusion

As stated above, the primary requirements for the Dry Fork Station are:

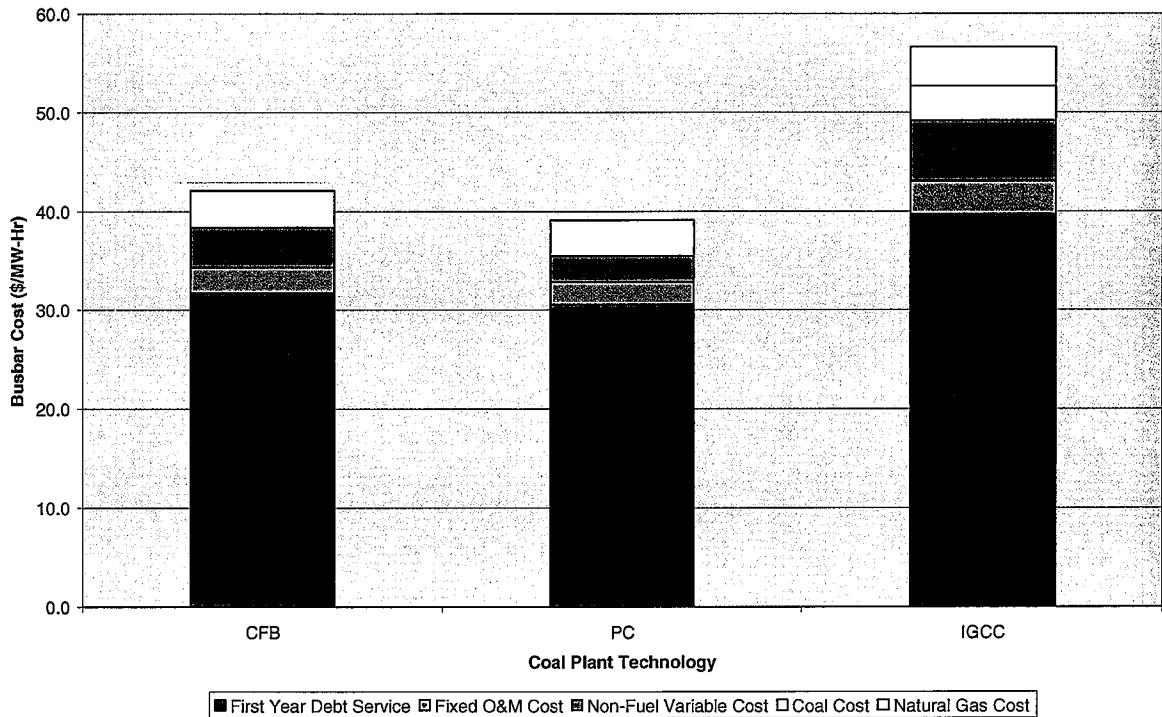
- Providing Baseload Capacity with High Reliability and Availability
- Assuring Environmental Compliance
- Utilizing Commercially Available and Proven Technology
- Generating Electricity at a Reasonable Cost

Based on the detailed analysis provided above, PC technology is evaluated as the technology best capable of fulfilling all of these requirements for new coal-based power generation, and is recommended for the Dry Fork Station Project. It will meet all of the design and operating characteristics required to satisfy the purpose and need for the plant.

CFB technology meets BEPC's need; however, it lacks demonstrated long-term operating experience on PRB coal and has not had sufficient commercial operation at the 368 MW size. IGCC technology is judged as not being capable of fulfilling the need for new coal-based generation, as it does not meet the requirement for a high level of availability and long-term, cost-effective power generation. The current approaches to improving availability are expected to result in higher cost and lower efficiency, negatively impacting the cost-effectiveness. In addition to higher capital costs, the technology is still in development, and is not yet commercially proven at large scale, even on eastern bituminous coal. No utilities have been able to obtain sufficient guarantees on cost, schedule or performance on IGCC reference plants. Further, IGCC technology is not commercially available at the 368 MW size needed for this project, either on eastern bituminous or PRB coal.

FIGURE 5

Coal Plant Technology - Busbar Cost of Electricity



2. BACT evaluation would reject IGCC

This BACT evaluation is based on a hypothetical scenario where IGCC is assumed to be included in the Top-down BACT Process as an emission control technology. The BACT process evaluates emission control technology on the defined source. IGCC, which is a power generating technology, and not an emission control technology, does not fit into the BACT mold. However, the following analysis attempts to consider IGCC in the BACT process.

The analysis clearly shows that IGCC would be rejected as BACT.

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 as follows:

- 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 SO₂, NO_x, PM, CO and VOC emissions and is described below.

2.1 Step 1 - Identify Available Control Technologies.

The first step is to identify all available combustion-related emission control technologies. Most recent PSD permit applications submitted to the applicable permitting agencies proposing to construct a coal-fired unit have defined the source as a 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 to be considered as alternative emission control technologies as part of recent BACT determinations, since they are different types of power generation technologies, not alternative emission control technologies.

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. Recent similar BACT determinations have evaluated the following potential combustion technology emission reduction options:

- Pulverized Coal (PC)
- Circulating Fluidized Bed (CFB)

IGCC is a type of power generation technology, not a "combustion technology emission reduction option" for using coal. IGCC is not a technology that one adds on to either the front end or back end of a PC or CFB unit for reducing emissions. It is a separate, unique power generation technology with a completely different basis of design than either PC or CFB. Requiring the use of IGCC would be redefining the design of the source. Therefore, it is not appropriate to include it in Step 1 of the BACT process.

2.2 Step 2 - Eliminate Technically Infeasible Options.

PC Option

The PC plant with FGD 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.

CFB Option

The majority of existing utility CFB units burn bituminous coal, anthracite coal waste or lignite. 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. The addition of these inerts results in lower combustion efficiency.

The CFB option is probably technically feasible for use in reducing SO₂ emissions from the new unit, but it is not considered the best application for PRB coal based on the reasons described above.

IGCC Option

At present, there are no IGCC units in operation using PRB coal. As noted above, the only coal gasification demonstration plant that operated with PRB coal was the LGTI plant, and it did not operate in IGCC configuration. The plant was shut down when the demonstration program was completed. While two 600 MW IGCC plants are in development, based on using PRB coal, it will be another 5 to 6 years before they will be in service and have operational data to determine the performance of IGCC using this feedstock. As noted above, one has been put on hold, and the other has not yet received its regulatory approvals (as noted above, the administrative law judges assigned to the case have recommended that the approvals be denied). Further, there is no actual performance, cost, or environmental data available for IGCC technology at a 368 MW size, using PRB coal at high altitude. Data for this case can only be estimated.

IGCC technology has been commercially offered for these two plants based on the reference plant design for 600 MW net at low elevation. As noted above, the formal request to the industry to provide a proposal for an IGCC plant that could meet the Dry Fork project's essential requirements for small size, low cost and high availability, along with commercial guarantees, resulted in no commercially viable offers. No other similar IGCC plants are

presently being designed with these key requirements for high availability, low cost, commercial guarantees, and the ability to use PRB coal at high altitude at this non-reference plant size or even at the reference plant size. For the purposes of the BACT process, IGCC is not technically feasible for the Dry Fork project.

Step 3 - Rank Control Technologies by Control Effectiveness.

If IGCC were technically feasible for Dry Fork Station, it would be evaluated for control effectiveness. Emission rates for each of the power generation technologies are provided in Table 4.

The emission limits shown for the proposed IGCC plant are based on data from air permit applications from several proposed IGCC projects. These limits are based on preliminary designs. This emission performance has not yet been demonstrated in actual operation, and won't be for another four to five years until these proposed units begin operation. The MDEA sulfur removal technology system has been in use at the Polk and Wabash River plants for more than a decade. Due to design changes based on lessons learned at these two plants, a higher level of removal of sulfur compounds is expected for the proposed plants. However, as noted above, it is yet to be demonstrated.

TABLE 4
Comparison of Coal-based Power Generation Technology Potential BACT Emission Rates
Basin Electric Dry Fork Station Technology Evaluation

| Pollutant | Emission Rates for Coal-based Power Generation Technologies (Lb/MMBtu) | | | |
|----------------------------------|--|------------------------|--|---|
| | PC w/Dry FGD and SCR | CFB w/Dry FGD and SNCR | Proposed IGCC w/MDEA Sulfur Removal / No SCR | Existing IGCC (w/MDEA Sulfur Removal / no SCR)* |
| SO ₂ | 0.080 | 0.080 | 0.025 | 0.170 |
| NO _x | 0.050 | 0.090 | 0.057 | 0.076 |
| PM ₁₀ (filterable) | 0.012 | 0.012 | 0.0063 | 0.013 |
| CO | 0.150 | 0.150 | 0.036 | 0.035 |
| VOC | 0.0037 | 0.0037 | 0.001 | 0.0017 |

Notes:

* Wabash River Station and Polk Power Station Existing U.S. IGCC Demonstration Plants.

The PC configuration selected uses a conventional high dust/high temperature SCR system for NO_x control, and a CDS FGD system for SO₂ removal. 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.

The CFB configuration selected uses a SNCR system for NO_x control, and limestone addition in the boiler with a downstream CDS FGD system for SO₂ removal. CFB

technology is an alternative coal combustion process that could be considered for this power plant application. However, there is limited CFB boiler experience with PRB coal.

The IGCC configuration selected uses an amine-based acid gas removal system (chemical solvent) to reduce H₂S to approximately 30 ppmv in the undiluted syngas sent to the combustion turbine generators (CTGs) for SO₂ control, and steam humidification and/or nitrogen injection in the CTGs for NO_x control. Depending on the CTG supplier, the nitrogen may be mixed with the syngas prior to the CTG, or may be injected into the burners.

IGCC is a promising technology which presents the opportunity for power generation at lower emissions of some criteria air pollutants than conventional PC technology. However, at this time, there is no experience with PRB coals in IGCC operation and there will not be for at least another five to six years when one or two IGCC plants might begin operation. While two IGCC plants designed for use with PRB coal have submitted air permit applications, neither plant has even been designed. The ability of IGCC technology, using PRB coal, to meet the projected emission limits is uncertain. There is no historical data to show that IGCC could or would be able to provide the most effective controls under step 3 of the BACT process.

2.3 Step 4 - Evaluate Most Effective Controls and Document Results

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

The coal plant technology configurations selected for evaluation are shown in Table 5. An incremental cost analysis has been prepared, and a summary of the results is shown in Table 6.

TABLE 5
Coal Plant Technology Evaluation Criteria
Basin Electric Dry Fork Station Technology Evaluation

| Criteria | PC w/Dry FGD and SCR | CFB w/Dry FGD and SNCR | Proposed IGCC w/MDEA Sulfur Removal / No SCR |
|----------------------------------|----------------------|---------------------------------|---|
| Net Plant Output (MW) | 368 MW | 368 MW | 368 MW |
| Net Plant Heat Rate (Btu/kWh) | 10,077 | 10,377 | 10,250 |
| Annual Plant Capacity Factor (%) | 90% Coal | 90% Coal | 5% Natural Gas, 85% Coal |
| SO ₂ Control System | CDS FGD | Limestone in Boiler and CDS FGD | Amine Syngas Treatment for H ₂ S Removal |
| NO _x Control System | LNB and SCR | SNCR | Nitrogen injection and Steam Humidification |
| CO Control System | Combustion Controls | Combustion Controls | Combustion Controls |

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

TABLE 6
Comparison of Coal-based Generation Technology Economics
Basin Electric Dry Fork Station Technology Evaluation

| Factor | Costs (\$) | | |
|---|------------------|------------------|------------------|
| | CFB | PC | IGCC |
| Total Installed Capital Costs | \$ 1,404,000,000 | \$ 1,350,000,000 | \$ 1,755,000,000 |
| Total Fixed & Variable O&M Costs | \$ 30,100,000 | \$ 24,900,000 | \$ 49,100,000 |
| Total Annualized Cost | \$ 122,300,000 | \$ 113,600,000 | \$ 164,400,000 |
| Incremental Annualized Cost Difference | - | (\$ 8,800,000) | \$ 50,800,000 |
| Incremental Tons Pollutants Removed: PC versus CFB, and IGCC versus PC * | - | 731 | 2,543 |
| Incremental Cost Effectiveness per Ton of Additional Pollutant Removed: PC versus CFB, and IGCC versus PC | - | N/A ** | 19,981*** |

Notes:

* Based on SO₂, NO_x, CO, VOC and PM₁₀ emissions removed.

** There is no incremental cost for the PC unit compared to the CFB unit because the PC unit has a lower annualized cost and removes more tons of regulated air emissions compared to the CFB unit.

*** This is the incremental cost per ton of pollutant removed comparing IGCC with PC technology.

There is no incremental cost for the PC unit compared to the CFB unit because the PC unit has a lower annualized cost and removes more tons of regulated air emissions compared to the CFB unit. The incremental cost of IGCC over PC is \$19,981 per additional ton of emission removed. With such high incremental costs, IGCC technology is not warranted for this project based on the use of low sulfur coal and the limited additional tons of emissions removed.

Step 5 – Select BACT

In Step 1 of the BACT process, IGCC was ruled out as an emission control technology option, primarily since it is a power generation technology, not an emission control technology option to be used when combusting coal, and its use would equate to redefining the basic design of the source. In Step 2, IGCC was rejected as a technically feasible option, primarily due to its poor historical performance on a handful of units, its complete lack of operational history using PRB coal at high altitude, and its inability to meet the project's essential requirement for low cost and high availability. In Step 3, the performance of existing IGCC technology shows that its proven emission performance is not significantly better than that of commercially proven PC and CFB technology. Step 4 showed that there is no historical data to prove that IGCC could or would be an effective emission control technology when using PRB coal at high altitude. IGCC was evaluated and clearly rejected at each of these key steps of the BACT process.

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 technologies, the PC plant design represents BACT for the proposed new unit.

3. CO₂ Capture

With the potential for reductions in greenhouse gas emissions, interest in the capture of carbon dioxide (CO₂) emissions from power plants has grown. While the capture (removal) of CO₂ is technically feasible, it has not yet been applied at high removal efficiencies at large, commercial scale PC, CFB or IGCC power plants. This also applies to the overall concept of carbon capture and sequestration (CCS). As clearly noted in the recent report, "The Future of Coal", prepared by the Massachusetts Institute of Technology (MIT), "There is no operational experience with carbon capture from coal plants and certainly not with an integrated sequestration operation." The MIT report also states that "neither IGCC nor other coal technologies have been demonstrated with CCS."

While there is limited CO₂ removal experience with the gasification of coal and pet coke, it is done at fairly small scale and only where the user of the CO₂ actually pays for the CO₂, offsetting the additional capital and operating costs for CO₂ removal. None of the operating IGCC plants incorporate CO₂ removal.

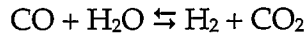
Whether for PC, CFB or IGCC, capture of CO₂ results in the following impacts on the overall plant:

- A significant increase in total plant capital cost for the large CO₂ absorption and concentration system
- A reduction in the plant's output (due to the steam extraction for the CO₂ absorption reactions and then for driving off the CO₂ from the sorbent for separation, as well as for higher internal load from additional pumps and for CO₂ compression)
- A reduction in plant efficiency
- A resulting increase in the cost of electricity

There are two general (mis)understandings of CO₂ emissions and IGCC. First, many believe that IGCC produces much lower CO₂ emissions than PC technology. This is not the case at all. When the Wabash River and Polk IGCC plants began operation, it was expected that the next generation of IGCC plants would be much more efficient than PC technology. However, this has not yet occurred. Data from the proposed IGCC plants being designed today for operation in the 2011-2013 timeframe show that they will actually be less efficient than PC plants planned for operation in the same time frame. Lower efficiency means using more coal for the same amount of electricity that is generated. Using more coal means higher emissions of CO₂. So PC presently has an edge over IGCC with respect to CO₂ emissions. Even if 90 percent CO₂ capture were to be applied to both technologies, the PC technology would still have lower CO₂ emissions than IGCC.

The second misunderstanding is that IGCC technology inherently captures all or a large portion of the CO₂. This is not the case. Significant additions of equipment are required for IGCC to incorporate CO₂ capture technology. Syngas from coal gasification has a CO₂ concentration of only 2-14%; this varies based on the coal and the gasifier technology. CO₂ is considered an acid gas, as it forms weakly acidic carbonic acid in water. It can be removed using acid gas removal (AGR) technology developed in the refinery industry.

In order to efficiently remove CO₂ from the syngas stream, the concentration of CO₂ must be substantially greater than the 2-14% range. The concentration of the CO₂ can be increased, using the water shift reaction shown below.



This reaction takes place over a catalyst bed, and requires the introduction of steam to provide the water needed to convert about 95% of the CO in the syngas to CO₂. In doing this, the water is converted to hydrogen, raising the concentration of hydrogen in the syngas going to the combustion turbine (this issue will be discussed later). This is an exothermic reaction, and the heat produced could be to generate steam for use elsewhere in the IGCC plant.

While AGR technology is also used to remove sulfur compounds from syngas, it is much smaller in size and less costly for that application than for CO₂ capture, since the solvents used in AGR systems have a much greater affinity for removing sulfur compounds than CO₂. This means that removing CO₂ from the syngas is much more difficult and expensive than only removing the H₂S.

For CO₂ capture, the IGCC plant must be modified significantly. Figure 6 shows an IGCC configuration without CO₂ capture. Figure 7 shows the placement of the water shift reactor prior to the CO₂ capture step, and then the substantially larger AGR system for both H₂S and CO₂ removal. The new items added for CO₂ capture are shown in red boxes. In Figure 6, the syngas stream going to the combustion turbines is normal syngas. In Figure 7, it is a concentrated stream of hydrogen.

FIGURE 6
IGCC without CO₂ Capture

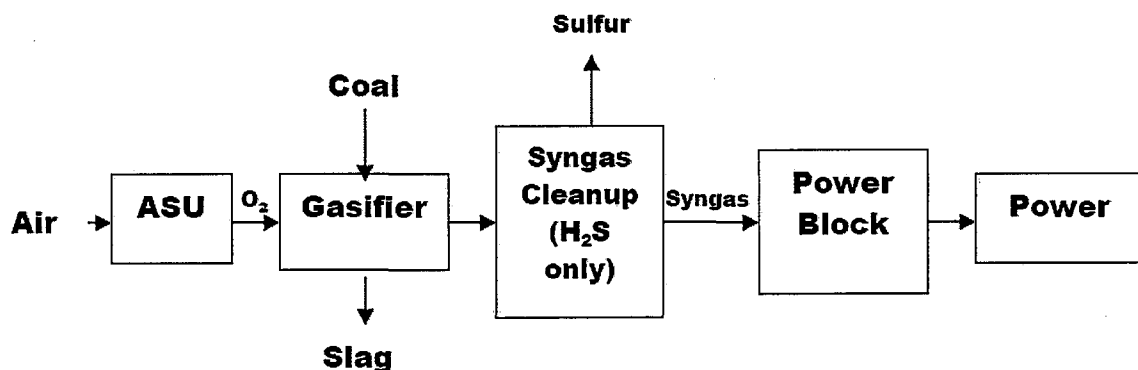
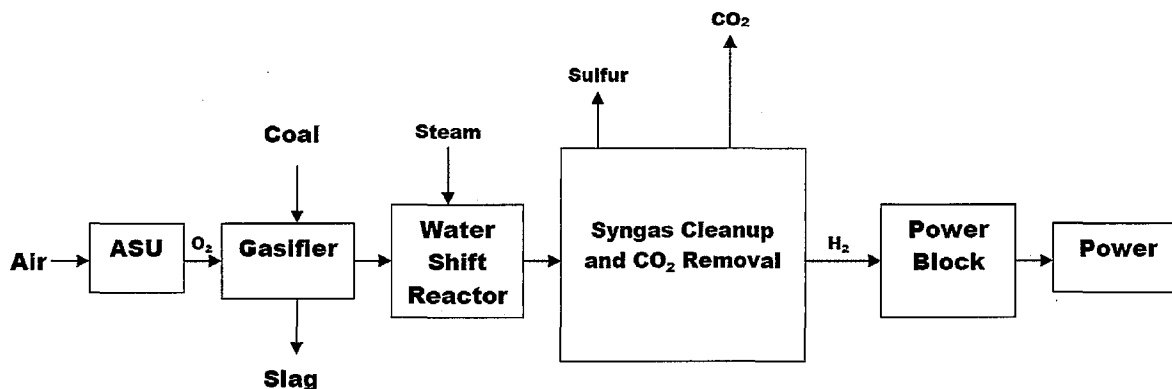


FIGURE 7
IGCC with Water Shift Reactor and CO₂ Capture System



After the water shift reactor, the syngas will have about 40% CO₂ and 50% H₂. At that point, the modified AGR system is capable of high removal of H₂S and capture of CO₂. Once the CO₂ is removed in concentrated form, it must be pressurized to greater than 2,000 psi for transport off the plant site, for use or sequestration.

The removal of the CO₂ results in a syngas with a very high concentration of hydrogen. While small industrial combustion turbines have experience in combusting syngas with a high hydrogen content, large frame combustion turbines capable of combusting this hydrogen-rich syngas are not yet commercially available at the sizes needed to support the 368 net MW Dry Fork plant. Combustion turbine manufacturers are involved in development work (with co-funding by the DOE) of these next-generation hydrogen-fired combustion turbines, with commercially available units expected in the 2014 timeframe. Major development is required in the fuel handling and mixing system, in order to safely and efficiently blend the hydrogen, back-up fuel (natural gas or fuel oil) and nitrogen.

R&D on CO₂ capture systems has been receiving much attention and funding. The goal is to increase the efficiency of CO₂ capture systems, while reducing the capital costs, heat rate penalties, and internal load requirements. Much work is needed over the next few years in order to reach these goals and to make this technology technically and commercially feasible at large scale.

The capture of CO₂ is only the first step. Capture would typically be followed by either use of the CO₂ for enhanced oil recovery or sequestration. While CO₂ is presently being used for enhanced oil recovery, long-term CO₂ sequestration is still in its infancy. The ability to sequester CO₂ in large amounts is directly dependent on the geology. While states such as Texas and Louisiana have large salt domes and geologic formations (i.e. deep saline aquifers and basalt layers) that can provide long-term sequestration, such good sequestration geology may not exist in Wyoming and adjacent states. Therefore, while CO₂ capture may one day become technically and economically feasible, the ability to sequester it on a safe, reliable, and long-term basis is likely to be a major hurdle in Wyoming and many other areas of the U.S.

Cost Impacts

For most large sources of CO₂ (e.g., power plants), the cost of capturing CO₂ is the largest component of overall CCS costs. CO₂ capture costs include the cost of compressing the CO₂ to a pressure suitable for pipeline transport (typically about 2,200 psia). However, the cost of any additional booster compressors that may be needed is typically included in the cost of transport and/or storage.

The total cost of CO₂ capture includes the additional capital requirements, plus added operating and maintenance costs incurred. For currently available technologies, a substantial portion of the overall cost is due to the energy requirements for CO₂ capture and compression. A large number of technical and economic factors related to the design and operation of both the CO₂ capture system and the power plant influence the overall cost of CO₂ capture. For this reason, the reported costs of CO₂ capture vary widely, even for similar applications.

DOE's new report, "Cost and Performance Baseline for Fossil Energy Plants", released in May 2007, shows that when using bituminous coal, the COE for IGCC with CO₂ capture is lower than for PC with CO₂ capture. However, as coal rank decreases (from bituminous to sub-bituminous and lignite), the COE for PC and IGCC tend to merge. In late 2006, the Electric Power Research Institute (EPRI) released its study that focused on the technical and economic impacts of CO₂ capture for PC and IGCC plants using PRB coal. In the EPRI report, the results show that the COE for the PC plant is actually 5.2 percent lower than that for the IGCC plant.

Until CO₂ capture technology is actually applied to large-scale PC and IGCC plants and significant experience is gained, the actual costs for CO₂ capture will remain a subject of intense study and uncertainty.

Efficiency and Output Impacts

There are substantial impacts on plant efficiency when adding CO₂ capture systems. In the noted DOE report, IGCC plant efficiency is reduced by 15 percent when CO₂ capture equipment is added in. Impacts on plant output are also substantial. Due to the large increase in steam use for the CO₂ capture system, the steam turbine output is decreased significantly. In addition, the internal load requirements for the CO₂ compressor are about 26-28 MW for a 600 MW IGCC plant, so that the plant's overall net output falls considerably. In the DOE study, the net output of the IGCC plant with CO₂ capture technology is reduced by 84 MW, which is an 11 percent reduction compared to the plant without CO₂ capture. This significant reduction in plant output must be replaced elsewhere on the generating system, probably by smaller, less-efficient units with higher CO₂ emissions per megawatt-hour of generation.