Appendix H
Alternative Coal-Fueled Generating Technologies

Report

Alternative Coal-Fueled Generating Technologies

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Background

The proposed action is an approximately 1,600-megawatt (MW) electric power plant, consisting of one to three supercritical pulverized coal-fired boilers that will produce steam for the steam turbine electric generator(s). Each generator is expected to have a nominal generating capacity of 500 MW to 800 MW. The boilers will be designed to maximize efficiency and minimize air pollution during the combustion process. Powder River Basin coal, a subbituminous coal, is expected to be the primary fuel for the facility, although other solid fuels may be used pending economic considerations and compliance with permitting limitations.

The three general categories of coal-fueled technologies considered in this report are as follows:

- Pulverized coal (PC) combustion technology (including subcritical, supercritical, and ultrasupercritical)
- Circulating fluidized bed (CFB) combustion technology
- Integrated gasification combined cycle (IGCC) technology

The purpose of this report is to provide information regarding these alternatives and the reasons why these alternatives were either carried forward or eliminated from detailed analysis. The following subsections evaluate each potential alternative, including assessments of the relevant technological, operating, efficiency, environmental, and economic issues.

The terms bituminous, subbituminous, lignite, waste coal and petroleum coke (petcoke) are used in this report to distinguish the different types of coals commonly used, as well as other solid fuels (petcoke). Definitions of the terms can be found in the Appendix A to this report. The classifications of coal are important, because the characteristics of solid fuels can vary greatly in terms of energy content, sulfur content, ash content, and moisture. Typically a specific solid fuel is selected for a power plant based on availability, transportation routes, costs, and environmental considerations. Once selected, the power plant will be designed to use this fuel over the life of the facility. A power plant may have the capability to burn coals other than the design fuel, but if the characteristics are significantly different, the power plant could be affected by one or more of the following:

- Reduced electric output
- Efficiency loss
- Increased maintenance and repairs
- Change in environmental performance

Pulverized Coal-Fired Combustion

Most coal-fired power plants in operation today use pulverized coal-fired boilers. Pulverized coal units use a proven technology that is capable of very high levels of reliability. There are two distinct categories of PC units: subcritical units and supercritical units. In a subcritical unit, steam is produced at pressures and temperatures below the critical point of the steam—steam conditions with a pressure below approximately 3,200 pounds per square inch (psi) and temperatures typically around 1,000°F. In a supercritical unit, supercritical steam fluid is generated at temperatures and pressures above the critical point—steam conditions with a pressure above approximately 3,200 psi and temperatures around 1,050°F. These technologies operate on the same basic principles to produce electricity, the difference being that supercritical units have steam conditions with higher operating temperatures and pressures, resulting in higher overall generating efficiency when compared to subcritical technology.

Recent advances in electrical generating unit technology have led to the creation of a new subset of the supercritical category, known as "ultra-supercritical" technology. The U.S. Department of Energy (DOE) has defined the ultra-supercritical steam cycle as a steam cycle with an operating pressure exceeding 3,600 psi and main superheat steam temperature approaching 1,100°F (DOE, 2005, p. 6).

Process Description

In a pulverized coal-fueled generating plant, coal is milled to a fine powder and blown into the boiler with hot air. The coal burns in suspension within the boiler. Low nitrogen oxides (NO_X) burners are used to reduce nitrogen oxide emissions and air-fuel ratios are used to reduce carbon monoxide (CO) emissions. Water is circulated through tubes lining the boiler and is turned into steam, which is used to propel a turbine-generator to produce electricity.

History

Pulverized coal-fired boiler technology is the primary means for generating power from coal with approximately 970,000 MW of capacity in operation worldwide and over 310,000 MW in the U.S. The majority of PC units in the U.S. are subcritical units built 25 to 50 years ago with steam pressures up to 2,400 psi and temperatures up to 1,050°F. Over 160 supercritical units were built in the U.S. from the 1960s to the early 1990s. However, many of these units had availability and operational problems. Because of these problems, supercritical technology fell out of favor in the U.S. Eventually, increased experience with the technology led to solutions, and numerous additional supercritical units have been built internationally. Today, both subcritical and supercritical PC technology are being constructed and operated in the U.S.

Advancements in metallurgy continue which allow higher temperature and pressure conditions and in turn increase the efficiency in the boiler. Overseas, some PC units have

been designed to operate at ultra-supercritical conditions exceeding 1,100°F and 3,600 psi. Ultra-supercritical units are being considered for new plants in the U.S. but would be operated below the more extreme steam conditions that may be found overseas.

Performance

Efficiency

Overall efficiency of power plant is expressed as percent efficiency, referring to the percentage of thermal energy in the coal that is converted to electrical energy, or by using the term heat rate, which measures the amount thermal energy required for the generation of one net kilowatt-hour (kwh) of electricity. In the U.S., the British Thermal Unit (Btu) is the unit of measure for thermal energy, and heat rates are typically stated as Btu/kwh. The efficiency of the unit increases with a higher the percent efficiency and a lower the heat rate.

The overall efficiency of a pulverized coal facility is affected by many factors, including, but not limited to, the steam conditions (for example, subcritical, supercritical), cooling system, parasitic load for auxiliary equipment (for example, emission controls, coal handling, etc.), and characteristics of the coal being used. Older subcritical units in the U.S. typically have efficiencies of 31 to 34 percent. Generally, current subcritical and supercritical designs with full environmental controls are expected to yield efficiencies in the range of 35 percent and 40 percent, with supercritical units at the upper end of range. Ultrasupercritical plants may be able to achieve efficiencies in the low 40 percent range.

The difference in efficiency between the various types of pulverized coal-fired generation varies based on the specific steam conditions used and the coal selected. Generally, the difference in efficiencies between subcritical and supercritical technologies may be between 1 percent and 3 percent. Similarly, the difference in efficiencies between supercritical and ultra-supercritical technologies may also be between 1 percent and 3 percent. The difference between modern supercritical plants and the ultrasupercritical plants being considered in the U.S. is thought to be approximately 1 percent.

Availability

Out of all of the coal-fired generating technologies, PC technology is the most proven and reliable. Unit availability is calculated by taking the number of hours in a year that the unit was available to produce power, dividing by the total number of hours in the year (8,760), and then multiplying by 100 percent. Unit availability levels exceeding 90 percent can be achieved today with the mature subcritical and supercritical technologies.

Fuel Source

PC technologies can be designed to burn various coal types including sub-bituminous, bituminous and lignite. PC technology has the flexibility to blend in a certain level of alternative types of solid fuel (for example, petcoke). However, once designed a PC unit generally operates using its design fuel in order to maximize output and efficiency and to minimize maintenance.

Operational Flexibility

PC-fired generation has proven operating flexibility to operate as baseload, load-following, and on-off cycling units. Minimum load for a PC-fired unit is in the range of 25 percent to 30 percent, without supplemental fuel.

Emissions

Emissions from PC technologies can be greatly reduced through the use of combustion practices and design (for example, low NO_X burners, overfire air) and post-combustion emission control equipment. Post-combustion emission controls include scrubbers for the control of sulfur dioxide (SO_2), selective catalytic reduction (SCR) for the control of NO_X, activated carbon injection for the control of mercury, and fabric filters (or a "baghouse") for the control of particulates.

The emissions from subcritical and supercritical designs are identical on a heat input basis (that is, pounds of emissions per million Btu of heat input). However, the overall emissions from a supercritical facility should be slightly less than a subcritical facility when producing the same amount of electric power, given the higher electrical generating efficiency of the supercritical design.

Cost

PC-fired generation is the most economic source of coal-fired generation, with firm pricing and performance guarantees available from multiple equipment vendors. There are cost advantages and disadvantages for using a supercritical design versus a subcritical design. The initial cost of a facility using a supercritical design is higher than a facility using a subcritical design. However, the ongoing cost of operations for a supercritical facility should be lower given the higher efficiency (that is, less fuel necessary to produce the same amount of electricity). Less information is currently available on the cost increases to use ultra-supercritical technology; however, it is generally accepted that capital costs for ultrasupercritical boilers are higher given that the technology relies on advanced materials to operate at the higher temperatures and pressures and there are fewer equipment suppliers for these boilers.

Commercial Use

Subcritical and supercritical PC boiler technologies are mature technologies, with the majority of coal-fired generation capacity in operation utilizing subcritical technology and more than 500 plants worldwide utilizing supercritical technology. Ultra-supercritical technology has very limited experience in the United States. In fact, a U.S. EPA report referring to ultrasupercritical technology with steam conditions of 4,500 psig and 1,100°F states that "[t]herefore, for application in this country, the technology is considered unproven with potential technical and economic risks" (EPA, 2006, p. ES-2).

Conclusion

Pulverized coal generation technology offers proven, reliable, and efficient operations. Low emission rates can be achieved through the use of pulverized coal technology with

advanced post-combustion technologies. Further, pulverized coal technology is the most economic method of coal-fired generation.

The Proposed Action is to use supercritical PC boiler technology. Subcritical PC technology does offer the potential for lower capital cost and has been considered as an alternative, but has been eliminated from detailed analysis because it does not offer any apparent environmental advantages, and the higher efficiency of a supercritical PC plant will at minimum offset a part of the higher cost through fuel savings.

Ultrasupercritical PC technology is a subset of supercritical PC boiler technology and as such the analysis conducted for supercritical technology envelopes the impacts of both technologies. The higher efficiency of ultrasupercritical PC technology does offer the potential for environmental advantages through less coal burned on per megawatt-hr basis, which in turn would slightly lower overall air emissions and solid waste on a pounds per megawatt-hour basis. Ultrasupercritical technology does represent a higher capital cost and represents greater operational risks because it has virtually no operating history in the U.S.

Circulating Fluidized Bed Combustion

Circulating fluidized bed is a power generation technology that combusts solid fuel held in suspension in a bed primarily consisting of fuel, fuel ash, limestone, and other inert materials. Circulating fluidized bed boiler technology has been successfully applied to the process industries and the electric power industry, although its application is limited by the smaller steam generating capacity that can be produced by a single circulating fluidized bed boiler (300 MW per circulating fluidized boiler). Without add-on controls, a circulating fluidized boiler can produce less NO_X and SO_2 emissions than an uncontrolled PC boiler; however, to achieve the currently required emissions levels, both circulating fluidized boilers and PC boilers must be equipped with add-on controls, thus removing the emissions advantage of circulating fluidized boilers. The circulating fluidized boiler continues to hold an advantage over the PC boiler with respect to its ability to burn a wider variety of coals and is well suited for waste coal.

Process Description

A circulating fluidized boiler combusts fuel in a bed of material consisting of fuel, fuel ash, limestone, and other inert bed materials. The bed is supported within the furnace by air flowing into the bed from the bottom of the furnace. The air flow supports the bed and promotes mixing of the fuel and air to provide complete combustion. The bed temperature is typically below 2,000°F, which maintains the fuel ash below the softening point and also reduces the formation of thermal NO_X. The bed is sized to achieve low gas velocities that allow for long fuel residence time in the furnace which helps complete combustion and maximize heat transfer to the water-cooled furnace walls. Simultaneous with the fuel combustion, limestone reacts with SO_2 formed during combustion to lower overall SO_2 emissions from the boiler.

The thorough mixing of air and fuel, low combustion temperature, long residence time, and in-situ removal of SO_2 make circulating fluidized technology an ideal system for the combustion of fuels with low volatile matter content (such as anthracite coals and petcoke), high ash content (such as waste coal), and high sulfur content. Additionally, a circulating fluidized boiler has greater fuel flexibility relative to a PC boiler, which gives an owner the ability to minimize fuel expenses by burning lower quality, lower cost fuels.

History

Fluidized bed technology development was initiated in the 1920s as a process for refining petroleum and producing chemical feedstocks from coal. Until the 1960s, fluidized bed technology was focused on the process industries. In the 1960s, governments (particularly in the U.S. and England) began looking at fluidized bed technology as a means to use coal while reducing emissions of SO_2 and NO_X. At that time, governments and boiler manufacturers began investing in the development of the technology and began building test modules and small scale commercial boilers. With the progression of time, a greater

understanding of the circulating fluidized technology was gained, which enabled boiler manufacturers to offer larger circulating fluidized boilers and expand the potential range of application from small industrial boilers to larger utility boilers.

The circulating fluidized combustion process is now a mature technology, and circulating fluidized boilers have gained acceptance as a steam generator technology for power generation. Table 1 summarizes some of the most recent domestic applications of circulating fluidized boilers for power generation.

TABLE 1
Domestic Circulating Fluidized Bed Boiler Applications for Power Generation

Plant	Location	Operation	Capacity MW (gross)	Fuel
Tractebel Red Hills	Mississippi	2001	2 x 250 MW	Lignite
JEA Northside	Florida	2001	2 x 300 MW	Coal, petcoke
AES Puerto Rico	Puerto Rico	2002	2 x 250 MW	Coal
Reliant Seward	Pennsylvania	2004	2 x 292 MW	Waste coal
East Kentucky Power Coop	Kentucky	2004	1 x 268 MW	Coal

Performance

Efficiency

The overall efficiency of a facility with a circulating fluidized bed boiler with advanced emission controls would be lower relative to a facility with a PC boiler with advanced emission controls because of lower combustion temperatures, smaller unit size, and higher power requirements of the circulating fluidized boiler auxiliaries. The efficiency of a circulating fluidized is several percent lower than a PC unit. The result of this lower efficiency is a higher fuel consumption rate for an equivalent electric generating capacity.

Availability

A limited amount of data is available for circulating fluidized bed units because of the fewer number of operating units and that most of the facilities are not required to report this information. However, circulating fluidized bed units are generally thought to have availabilities approaching 90 percent.

Fuel Source

The advantage of a circulating fluidized bed boiler is its ability to consume low cost “advantage” fuels not typically used in a PC boiler. These fuels are characterized by a high ash or moisture content, low heating value, and low volatile content and thus are lower cost on a $/MMBtu basis at the fuel source. Additionally, circulating fluidized bed boilers are able to burn biomass as a fuel source, making the attractive in areas that have large amounts of biomass available for a renewable fuel source. Transportation cost is a critical

consideration in determining the fuel source and, in the case of using lower value fuels, transportation distances exceeding 50 to 100 miles often removes any economic benefit of burning the lower value fuel relative to high quality subbituminous or bituminous coal. Long-term availability of these lower value fuels is also a consideration since a facility's economics will be severely impacted if the fuel source is no longer available in future years and higher cost fuels must be substituted. Therefore, most facilities equipped with a circulating fluidized bed boiler are located near one or more potential fuel sources to maximize the economic benefit of using the low value fuel and reduce the risk of fuel becoming unavailable.

Operational Flexibility

Circulating fluidized bed boilers have a more restrictive ramp rate than PC boilers because of the considerable mass of material in the bed that needs to be moved and kept within temperature ranges. Circulating fluidized bed boilers can operate at baseload and in a load-following mode. The load-following capability is limited in comparison to PC boilers. Minimum load for a circulating fluidized bed boiler is in range of 40 percent, without supplemental fuel (compared to the minimum load for a PC boiler in the range of 25 percent). Circulating fluidized bed technology is not well suited for on-off cycling. The bed material is susceptible to hardening if the bed temperature falls below its recommended operating range (Sargent & Lundy, 2005).

Emissions

The main advantage of a circulating fluidized bed boiler would be the lower emissions of NO_X and SO_2 relative to a PC boiler not equipped with selective catalytic reduction (SCR) or flue gas desulfurization (FGD). The lower combustion temperature of a circulating fluidized bed boiler would generate less thermal NO_X, while SO_2 emissions would be reduced by the reaction with limestone in the bed.

Recent facilities equipped with circulating fluidized bed boilers have used post-combustion controls to further reduce emissions of NO_X and SO_2 to meet the increasingly stringent emissions requirements. The controls typically applied are selective noncatalytic reduction systems (SNCR) to reduce NO_X emissions and dry FGD systems to reduce SO_2 emissions. An SNCR reduces NO_X by injecting urea or ammonia into the furnace which reacts with NO_X to form nitrogen (N_2), oxygen (O_2), and water. A dry FGD system may use bed material collected in a baghouse as the reagent or fresh lime feed similar to a dry FGD system installed with a PC boiler. The use of bed material or lime as the reagent in the dry FGD system is an economic decision based on the amount of additional SO_2 reduction required and the relative costs of limestone and lime.

Similar to recent circulating fluidized bed boiler installations, a new PC boiler would be required to install post-combustion controls to reduce emissions of NO_X and SO_2. The systems typically installed are SCR for control of NO_X emissions and FGD for control of SO_2 emissions. The addition of these systems enables a PC boiler facility to have emissions equal to the emissions from a facility equipped with a circulating fluidized bed boiler, SNCR, and dry FGD system. However, a facility equipped with a circulating fluidized bed boiler will have a lower overall efficiency than a comparably sized facility equipped with a PC boiler because of greater auxiliary power requirements of the circulating fluidized bed boiler

facility. Therefore, more fuel will have to be burned to produce the same amount of electricity, likely leading to greater total annual emissions at a circulating fluidized bed facility than a PC plant.

The amount of combustion products generated by a facility equipped with a circulating fluidized bed boiler and a dry flue gas desulfurization (FGD) system would be higher than a facility equipped with a PC boiler and a dry FGD system as a result of the overall lower efficiency of the CFB boiler based facility and the higher limestone consumption of a CFB boiler relative to the lime consumption of a PC boiler equipped with a dry FGD system. Table 2 shows a comparison of the fuel and reagents consumed by each technology and byproducts generated for a 600-MW facility firing PRB coals. A 600-MW plant is used since that would maximize the efficiency for CFB boilers (two 300-MW circulating fluidized bed units).

TABLE 2
Comparison of Fuel Consumption and Solid Waste Generation for a 600-MW Plant

Throughput	Two CFB Boilers (tpy)	PC Boiler (tpy)
Fuel consumption	3,222,749	3,154,383
Incremental fuel consumption	68,366	--
Fuel ash	165,971	159,699
Sulfur absorption products	117,849	64,375
Incremental disposal volume	53,474	--

Cost

Five or six circulating fluidized bed units would be needed in order to generate the steam flows required to generate 1,600 MW, which is the maximum proposed capacity for the proposed action. The use of additional boilers to achieve a given steam flow is more costly because of the increased physical size of the facility, the incremental ancillary equipment to support additional boilers (for example, conveyors, control systems), and the incremental staff to operate and maintain the additional boilers.

Commercial Use

Circulating fluidized bed boiler technology is a mature technology that is commercially available from multiple suppliers. Application of a circulating fluidized bed boiler is principally driven by the fuel to be consumed. A single circulating fluidized bed boiler is currently limited in capacity to approximately 300 MW; greater capacities would require multiple boilers. In contrast, a single PC boiler can be furnished with a capacity up to approximately 1,000 MW.

Conclusion

Circulating fluidized bed boiler technology is alternative considered but not carried forward for detailed analysis in the EIS because it does not offer any apparent environmental or economic advantages over the proposed action as summarized below:

- Five or six CFB units would be required versus the two or three supercritical pulverized coal units. This would cause an increase in the project's footprint and increase capital and operational costs because of loss of economy-of-scale.
- No reliable local fuel sources are available that could be used to realize the advantage of the CFB boiler technology.
- On a heat input basis (lb/MMBtu), most emissions would be similar to the proposed supercritical pulverized-coal power plant; however the CFB technology has lower overall efficiency, which would cause it to generate more emissions on a pounds per hour basis.
- A 1,600-MW CFB plant would consume approximately 181,000 tons per year of additional coal, increasing air emissions and coal deliveries as compared to the proposed action.
- A 1,600-MW CFB plant would create approximately 142,000 tons per year of additional solid waste for disposal as compared to the proposed action.

Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC) is an evolving power generation technology relying on gas turbine technology to produce electricity and offering the potential for improved environmental performance and high efficiency. IGCC is a two-step power generation method that produces synthesis gas (syngas) through the gasification of a solid or liquid feedstock (for example, coal, petcoke, or heavy oil), and also uses the syngas to power a combined cycle power block (combustion turbine in combination with a heat recovery steam generator and steam turbine). Emission controls are generally installed pre-combustion in an IGCC facility as compared to PC and CFB coal-fired generation technologies, where emission controls are generally installed post-combustion.

IGCC technology is a combination of processes from the petrochemical industry (gasification to generate syngas) and the power industry (gas-fired combined cycle power generation). In the petrochemical industry, gasification is used worldwide to produce a variety of products. In the power generation industry, however, the application of the gasification process to supply syngas to combustion turbines is limited to a very small number of plants operating in the U.S. and other parts of the world. Facility sizes for these installations range in size from 40 MW to 320 MW.

Currently, carbon capture and sequestration (CCS) technology has not been demonstrated in practice for a coal-fueled IGCC unit (Katzer et al., 2007, p. xiii). Thus, the viability of CCS technology in conjunction with IGCC for power generation has not been proven. Consequently, the discussions in the following text focus on IGCC without carbon capture, a technology that has been demonstrated in practice. A detailed discussion of CCS technology with respect to IGCC is provided in the section *Carbon Capture and Sequestration for IGCC Units*.

Process Description

There are actually four separate primary processes in an IGCC power plant, only one of which produces electricity: gasification, syngas cleanup, cryogenic air separation, and combined cycle power generation. Three of the four required processes are foreign to the conventional power generation industry and are typically classified as belonging to the chemical industry.

Gasifiers

Gasification is the process of converting a liquid or solid feedstock in a gasifier to a gas mixture (referred to as syngas) primarily composed of hydrogen and carbon monoxide. Gasifiers are generally classified into one of three categories: moving-bed reactor, fluidized-bed reactor, and entrained-flow reactor. Each of the technologies converts a carbon based feedstock in the presence of oxygen and steam while at high pressure and temperature into raw syngas which is primarily composed of hydrogen and carbon monoxide. The raw syngas also contains carbon dioxide, moisture, hydrogen sulfide, carbonyl sulfide, methane,

ammonia, hydrogen chloride, and trace amounts of other components present in the feedstock.

In a moving-bed reactor, large particles of coal move slowly down through the gasifier while reacting with gases moving up through it. This counterflow pattern creates several different reaction zones that accomplish the gasification process at temperatures averaging 1,470°F to 1,830°F.

Fluidized-bed reactors continuously feed coal into a 1,470°F to 1,650°F reactor so that coal at all stages of the reaction process is in the same reaction zone. Steam and oxygen/air are fed from the bottom and rise up through the bed of coal.

Entrained-flow reactors mix a stream of fine coal particles with steam and oxygen/air at high temperatures of 2,730°F to 3,450°F to create a stream of tar and oil free crude gas.

In theory, each gasifier configuration can be designed to use either air or oxygen to react with the coal for syngas production; however, only oxygen-blown systems have currently been proven at commercial scale. Air blown systems have been attempted but not successfully scaled up to commercial size as evidenced by experience at the air-blown fluidized bed KRW gasifier at the Piñon Pine IGCC facility near Reno, Nevada. This unit was converted to operation as a conventional natural gas-fired generating plant in the mid 1990s after it failed to reach steady state IGCC operation.

Syngas Cleanup

After gasification, some levels of impurities, depending on the removal technology chosen, such as sulfur compounds, metals, alkalytes, ash, and ammonia are removed from the syngas in the gas clean-up process to reduce the ultimate level of emissions and prevent corrosion of the combustion turbine.

The syngas typically exits the gasifier at high temperature and must be cleaned of pollutants and other constituents that can cause corrosion and/or erosion to downstream equipment. Currently available technologies for syngas cleanup require the gas to be cooled to approximately 400°F so that the majority of the hydrogen sulfide and other byproducts can be removed. However, cooling of the syngas for cleanup results in an efficiency loss in the system; therefore, it is preferable to be able to clean the syngas at the gasifier exit temperature. Systems have been proposed for syngas cleanup at higher temperatures (1,000°F to 1,250°F), but those systems have not yet been commercially successful. Research continues into the development of an operable hot gas cleanup system.

Cryogenic Air Separation

The cryogenic air separation process provides the oxygen necessary for the gasification process and can be integrated with the combined cycle power block to provide nitrogen gas to the gas turbines to reduce NO_X emissions. Current gasification processes require a compressed oxygen feed to the gasifier, which is generated by an air separation unit. Compressed oxygen generation is well proven and used extensively worldwide; however, the process is very expensive and energy intensive.

Combustion Turbine Combined Cycle

After the three chemical processes are completed, the cleaned syngas is supplied to a gas combustion turbine for use in a combined cycle power block. Because of the lower heat content of syngas relative to natural gas, the mass flow through the combustion turbine needs to be much higher with syngas, thereby affecting the ease at which some combustion turbines can be converted to syngas use. Nitrogen from the air separation unit or steam can be injected into the combustion turbine to reduce the flame temperature and reduce the NO_X emissions.

History

While gasification technology has existed since the 1870s and was used extensively by Germany, France, and Britain during World War II to create fuel, the integration of the chemical gasification process equipment with a gas-fired combined cycle power block for electricity production is a more recent and still-developing technology. In general, there have been two generations of IGCC power plants built; the first generation in the mid-1980s, and the second generation in the mid-1990s. Both generations have relied heavily upon government funding and financing, and neither have been scaled up larger than 321 MW in size.

Table 3 summarizes the IGCC coal-fired power plants built to date which use oxygen-blown, pressurized entrained flow gasification. Note that none have exclusively used Powder River Basin (subbituminous) coal.

TABLE 3
Coal-Fired IGCC Power Plant Summary

Plant	Location	Operation	Power MW (net)	Design Feedstock	ASU-CT Integration	Financial Support
SCE Cool Water	Barstow, California	1984-1988	120	Bituminous Coal	None	EPRI and Utility Consortium
LGTI (Destec/Dow)	Plaquemine, Louisiana	1987-1995	160	Subbituminous Coal natural gas blend (80/20)	None	Partial DOE
NUON (Demkolec B.V.)	Buggenum, The Netherlands	1994 – present	254	Bituminous coal	100%	Netherlands government support
Global Energy – PSI Wabash River (Destec)	Terre Haute, Indiana	1996 – present	262	Bituminous Coal (now 100% petcoke)	None	Partial DOE
TECO Polk Power Station	Polk, Florida	1996 – present	260	Bituminous Coal and Petcoke	None	Partial DOE
Frontier Oil & Refining Co.	El Dorado, Kansas	1996 – present	40 (cogen)	Petcoke	<25%	State tax-exempt bonds for use of petcoke
Elcogas S.A.	Puetollano, Spain	1997 – present	321	Coal and petcoke	100%	Spanish government support
Motiva Enterprises Refinery	Delaware City, Delaware	2000 – present	180	Petcoke	N.A.	State tax-exempt bonds for use of petcoke

While several of the plants were originally designed to operate on coal, of the six IGCC plants presently operating, only one operates exclusively on coal, while the rest fire either a combination of petcoke and coal or 100 percent petcoke. In a report for Illinois on the possibility of using IGCC at the Prairie State Generating Station, SFA Pacific noted that switching to petcoke improved the availability of the Wabash River facility (the facility was able to run more reliably and often using petcoke) (SFA Pacific, 2003). The gasification of petcoke is not directly comparable to gasification of coal because petcoke is a byproduct of refining processes and has characteristics different than coal. To date most gasification of coal has centered on bituminous coals, and only limited research has been conducted on the gasification of lower rank coals, such as subbituminous Powder River Basin coal. Without additional research or commercial experience, it is difficult to compare the gasification technology development with low rank coals to that of bituminous coal (EPA, 2006).

Currently there are six IGCC technology owners. These technology owners typically license the technology to third parties who would be responsible for the detailed design and erection of an IGCC electric generation facility. While two of the owners have partnered with construction firms with the intent of providing turnkey IGCC facilities, neither consortium has yet provided firm cost and performance guarantees for an IGCC power generating facility.[1] Firm pricing and performance guarantees are critical for making a project commercially viable. Without firm pricing, neither the project owner nor the lending institution(s) would have any assurance that the amount financed would be sufficient to complete construction of the facility and allow the owner to satisfy its loan payment obligations. As a result, any cost overruns would need to be passed on to electric customers, which would present a similar issue for the customers as they would not want to be responsible for substantial price increases. Similarly, without performance guarantees, neither the project owner nor the lending institution(s) would have any assurance that the proposed IGCC facility could meet its obligations to supply reliable baseload power. The financial penalties that could result from unreliable IGCC performance (for example, availability penalties under power contracts or lost revenue because of generation outages) could jeopardize the proponent's ability to satisfy its loan payment obligations. In addition, if the environmental performance requirements are not met (for example, efficiency is not met or emissions are higher) the project would be subject to environmental fines and could face potential shutdown of operations. Because of these financial risks, along with the technical risks to be discussed in subsections below, units representing this next generation of IGCC technology have not been financed, constructed, and operated successfully. As such, the cost, actual efficiency, availability, and environmental performance of the next generation of IGCC plants remain uncertain.

Table 4 lists the current IGCC projects that have been recently permitted in the U.S. It is acknowledged that a number of additional IGCC projects are in various stages of development in a number of different states across the U.S.

[1] For example, in recent testimony before the Virginia State Corporation Commission, Appalachian Power Company asserted with regards to its proposed IGCC plant in West Virginia "that GE/Bechtel are willing to *consider* guarantees of the performance of this [IGCC] plant *after* it begins operation." [original italics] (See Commonwealth of Virginia State Corporation Commission, Final Order, Case No. PUE-2007-00068, April 14, 2008.)

TABLE 4
IGCC Projects Permitted

Plant	Location	Net Power (MW)	Primary Fuel	Permit Status	Construction Status	Financial Support
Kentucky Pioneer	Kentucky	580	Unknown	Permit expired June 2006	IGCC Project Suspended by Developer	DOE Grant of $78 million [a]
Lima Energy	Ohio	540	Petcoke	Permit issued March 2002	Pending Financing [b]	--
Elm Road	Wisconsin	600	Bituminous coal	Permit issued January 2004	IGCC Project Denied by Wisconsin PSC	--
Stanton	Florida	285	PRB	Permit issued December 2006	Cancelled November 2007	DOE Grant of $235 million
Taylorville Energy Center	Illinois	630	Bituminous coal	Permit issued June 2007	Not started	Cost Recovery Guarantee [c]
Duke Energy	Indiana	630	Indiana coal	Permit issued November 2007	Construction uncertain pending air permit appeals process	--

[a] Global Energy, 2007
[b] Global Energy, 2007
[c] Blankinship, 2007

Table 5 lists the project summary of the IGCC projects that have been announced to date. Of the 20 projects shown in Table 5, the following can be said:

- Permitted = 6
- Canceled = 8
- On hold = 7
- Construction = 0
- That have incorporated carbon capture = 4 (all of which have been postponed or cancelled)
- Proposed at elevations less than 4,000 feet amsl = 17
- Proposed at elevations above 4,000 feet amsl = 3 (all of which have been postponed or cancelled)
- Proposed IGCC plant capacities are average 597 MW, with a maximum of 1,100 MW and a minimum of 275 MW.

Performance

A potential advantage of IGCC is that IGCC technology theoretically has superior thermal efficiency and environmental performance over other coal technologies. Concerns with IGCC include the maturity of the technology for commercial use, the reliability, the cost, and whether the efficiency and environmental performance can actually be achieved.

TABLE 5
IGCC Project Summary

IGCC Facility	Capacity (MW)	Fuel	Regulatory & Financial Incentives	Carbon Capture?	Approx. Site Elevation (ft amsl)	Status/Date Cancelled
Duke – Edwardsport, Indiana	630	Indiana coal	Total $460M federal, state, and local incentives including $133.5M DOE tax credit. Granted guaranteed cost recovery by the Indiana Utility Regulatory Commission for all construction, operating, and maintenance costs.	No	500	Under development. Air permit under appeal by Sierra Club and others. Construction uncertain pending air permit appeals process.
AEP – Great Bend, Meigs County, Ohio	629	Primary: Northern Appalachian coal Secondary: petcoke, natural gas	Rate recovery of $23.7M in pre-construction costs granted. AEP requiring regulated rate of return for project with cost recovery assurances in order to construct.	No	600	On hold because of March 2008 deregulation decision by Ohio Supreme Court. Uncertain if project will be allowed to obtain cost recovery for construction.
Tenaska – Taylorville Energy Center, Taylorville, Illinois	630	Illinois coal	$5M from state of Illinois, $500M in tax exempt bonds. Project requires new state legislation to require utilities to enter into long-term contracts purchasing power from the project.	No	600	Under development. Has not received long-term power purchase agreements. Air permit under appeal by Sierra Club.
Pacificorp – Jim Bridger, Wyoming	500	Coal	Severance tax exemptions on coal	Not specified	6,600	Cancelled November 2007.
Tampa Electric – Polk Unit 6, Polk County, Florida	630	Coal-bituminous	$133.5M DOE tax credit	No	100	Cancelled October 2007.
Southern Co. & Orlando Utilities Commission – Stanton Energy Center, Orlando, Florida	285	Coal - PRB	$235M DOE funding	No	100	Cancelled November 2007.
FutureGen Alliance – Mattoon, Illinois	275	Coal	$1,100M DOE funding prior to program restructuring. DOE has withdrawn financial support for the Mattoon site as part of project restructuring.	Yes	700	Status uncertain because of rising costs. DOE restructured the program in January 2008 to fund only the CCS portion of multiple IGCC plants in the future.

TABLE 5
IGCC Project Summary

IGCC Facility	Capacity (MW)	Fuel	Regulatory & Financial Incentives	Carbon Capture?	Approx. Site Elevation (ft amsl)	Status/Date Cancelled
Xcel Energy – Colorado	600	Coal	$3M per year to study IGCC in Colorado per HB 1281	Yes	4,200	Postponed October 2007. High cost, unable to find partners.
Cash Creek Generation, LLC (Erora Group) – Henderson County, Kentucky	630	Kentucky mine-mouth coal	grant from the KEDFA and the Commerce Cabinet for the office of Energy Policy for $303,000	No	500	Under development. Final air permit issued 01/17/08. Air permit under appeal.
WE Energy – Elm Road Generating Station, Wisconsin	615	Northern Appalachian Coal	Not specified	Not specified	700	Cancelled November 2003.
Excelsior Energy – Mesaba, Taconite, Minnesota	600	PRB Coal	$36M DOE grant, $800M federal loan guarantees, $12M in bond financing to Itasca County, $10M loan for start-up costs from Iron Range Resources, $10M grant from PUC, 2003 state law requiring Xcel to purchase 450 MW	No	1,400	On hold. Unable to obtain purchase agreements.
Energy Northwest – Pacific Mountain Energy Center, Washington	600	Coal or petroleum coke	Not specified	No	1,500	Cancelled December 2007.
United Power Company, Quigg Energy Group, LLC, and Washington and Sunwest Management, Inc. – Wallula Energy Resource Center, Walla Walla County, Washington	700	Coal	Not specified	Yes – approx. 65% capture	1,000	On hold. IGCC plant was contingent on results of a carbon storage pilot project. Pilot project was postponed indefinitely in March 2008.
Tondu – Nueces, Texas	600	Originally petcoke and coal. Now natural gas.	Not specified	Not specified	16	IGCC plans cancelled. Switched to natural gas in June 2007 because of high cost.

TABLE 5
IGCC Project Summary

IGCC Facility	Capacity (MW)	Fuel	Regulatory & Financial Incentives	Carbon Capture?	Approx. Site Elevation (ft amsl)	Status/Date Cancelled
Bowie Power - Arizona	600	Coal	Applied for DOE funding	Yes – Up to 4% capture in plants	3,800	Cancelled IGCC September 2007. Development started as Natural 1,000-MW gas. Switched to 600-MW IGCC in 2006. Switched back to natural gas in 2007. Market economics, regulatory uncertainty stated as reasons.
AEP – Mountaineer, New Haven, West Virginia	629	Coal	$133.5M in tax credits, project is contingent on obtaining guaranteed cost recovery	No	600	Permitting stage. Draft air permit as early as April 2008.
Global Energy, Inc. – Lima Ohio	540	Petcoke	Not specified	No	900	Permitted. Began construction in October 2005. Delayed pending financing
AEP/Madison Power – Southern Illinois Clean Energy Center, Illinois	Approx. 600	Illinois coal	$5 million in funding from the State of Illinois for the engineering and design study. $2.5 million grant by the Illinois Clean Coal Review Board for the initial phase of detailed engineering design	No	400	Not specified. No developments since 2006.
Buffalo Energy Partners – Converse County, Wyoming	1,100	Western coal	Not specified	Not specified	5,700	Cancelled October 2007.
Global Energy – Kentucky Pioneer, Kentucky	540	Co-feed of coal and refuse derived fuel	Cost-shared with DOE under Clean Coal Technology Program. DOE to provide $60 million in Federal funding support (about 15% of the total cost of approx. $414 million) to design, construct, and demonstrate the commercial scale operation of the technology.	Not specified	800	Permitted, not constructed. In 2006, project suspended and no longer considered probable in near term.

Efficiency

One stated goal for the IGCC technology is to achieve overall efficiency levels of 45 to 50 percent by 2010 and 50 to 60 percent by 2020 (Morehead, et al., 2004). These high efficiencies have not yet been achieved in practice by the four operating IGCC facilities as actual efficiencies have ranged from the mid-thirty to forty percent. These efficiencies can and are being achieved by recently built PC facilities. For example, Table 6 shows the actual historical heat rates for the Polk Power Station IGCC facility during the last 10 years (note: the lower the heat rate, the more efficient a plant is), which calculate to efficiencies between 31.2 percent and 35.9 percent. Many existing PC plants are achieving these efficiencies in the range of 31.2 percent to 35.9 percent, and this efficiency range would be surpassed by a modern supercritical PC plant. The use of combustion turbines at high elevations, such as the Proposed Action, results in a lower the net output because of the lower density of air.

TABLE 6
Polk Power Station Historical Heat Rate

	Polk Power Station*									
Year	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
Heat Rate (Btu/kWh)	10,523	10,909	10,950	9,495	9,775	9,633	9,674	9,815	9,934	10,146

* EPA, 2008

Availability

In an article in October 2006, *Power* magazine reported that the availability histories of the six successful IGCC demonstration projects show that most were able to reach the 70 percent to 80 percent availability range but only after at least 5 years of operation (Javetski, 2006). In comparison, PC-fired generation has been shown to have an expected minimum availability of 90 percent generally achievable within the first year of commercial operation. Table 7 shows the IGCC equivalent availability for the Nuon, Wabash, Polk, and Elogas plants which show that all had availabilities 60 percent and below during the first 3 years of operation, and only one has managed to obtain 80 percent after 7 years of operations.

Although not an IGCC power plant facility as it does not generate electricity, the Eastman Kodak Facility in Tennessee has been cited as a successful implementation of gasification technology because of its 2000 to 2003 reliability of 98.1 percent. It should be noted that this reliability figure does not include the power generation equipment that would be necessary for an IGCC power plant facility, is based on a facility equipped with a spare gasifier which adds significantly to the initial capital cost, and has been achieved in part because of having 20 years of operating experience with this facility (Trapp, 2004).

TABLE 7
IGCC Equivalent Availability*

Plant	Nuon	Global Energy (Wabash)	TECO (Polk)	Elogas
Gasifier	Shell	COP E-Gas	GE HTHR	Prenflo
Net Output	252 MW	262 MW	250 MW	300 MW
Years after Startup		**IGCC Equivalent Availability (percent)**		
1	23	20	35	16
2	29	43	67	38
3	50	60	60	59
4	60	40	75	62
5	61	70	69	66
6	60	69	74	58
7	57	75	68	NA
8	67	78	81	
9	73	-	82	
10	78	-		
11	NA			

Notes:

1. Data are based upon available information. Data reporting methodology varies somewhat between plants.
2. Wabash Years 5 to 8 IGCC equivalent availability estimated as 95% of reported syngas availability.
3. Wabash availability excludes periods when the plant was shut down because of no product demand (24% in Year 7 – 2002 and 16% in Year 8 – 2003, shutdown in Year 9 – 2004 and Year 10 – 2005).

* Black & Veatch, 2007

Fuel Source

No IGCC units exist which have currently or historically operated on 100 percent subbituminous PRB coal, which is the design fuel for the Proposed Action. Relatively little research or commercial work has been done to investigate gasification of the lower rank coals, including subbituminous and lignite, for electric generation purposes (EPA, 2006). This lack of experience is highlighted by the $235 million in government funding given to Southern Company to build a 285-MW PRB-fired IGCC demonstration unit in Orange County, Florida (this project was terminated two months after construction began because of regulatory uncertainties and will now be built as a natural-gas fired plant) (Orlando Utilities Commission, 2007). Furthermore, the Energy Policy Act of 2005 allows for funding to support an IGCC project using western coal. While vendors claim that PRB can be gasified, they also indicate that the fuel feed system and overall heat rate will be affected. GE, one of the IGCC technology owners, has stated that PRB coal is only ready for gasification in the short term if blended with petcoke (GE, 2005). This lack of IGCC experience with western coals is supported by American Electric Power (AEP), a company currently proposing to construct both IGCC and PC facilities. AEP has stated that "the IGCC technology developed by GE does not work well with western coals that have lower Btu

value and higher moisture content than eastern coals. Although competing gasification technology can use western coals, the owners of this technology are not yet providing performance guarantees necessary to make it a commercially viable option" (Rencheck, 2007).

Operational Flexibility

The operational flexibility of IGCC units is significantly less than that of PC-fired generation. PC-fired generation has proven operating flexibility to operate as baseload, load-following, and on-off cycling units. Minimum load for a PC-fired unit is in the range of 25 percent to 30 percent, without supplemental fuel. IGCC is best operated only as baseload. For a 2 x 2 configuration, with two combustion turbines and two gasifiers, some load following can be accomplished, either by load reducing on individual combustion turbines (range is 60 percent to 100 percent) or shutting down a gasifier/combustion turbine train. The gasifiers are best operated at a constant rate rather than cycled. The operating range of the gas turbine is typically 60 percent to 100 percent, with the heat rate deteriorating at lower loads (Sargent & Lundy, 2005).

The lower reliability of IGCC plants and the resulting increase in the number of annual starts, shutdowns, and malfunctions has the potential to consume additional energy from the grid and/or increase the total annual emissions emitted from the facility. Another operational disadvantage is that an IGCC facility firing syngas takes longer to start up than does a PC-fired unit (Sargent & Lundy, 2005).

Emissions

Emissions data is generally available for the existing generation of IGCC facilities in operation in the United States and the emission reductions have generally not exceeded what can be accomplished with a modern PC plant. While it may be possible to further reduce the pollutant emissions for the next generation of IGCC facilities through modifications to the control process or addition of specialized pollution control units, this would further add to the cost and complexity of an IGCC plant. Further, this next generation of IGCC facilities has yet to be constructed and, and as such, any lower emission levels have not been demonstrated and cannot be considered a reliable point of comparison to the mature and reliable PC-fired technology. A number of proposed IGCC projects are being permitted throughout the U.S. with varying emission rates proposed. However, none of these projects have been constructed, and emission rate guarantees by vendors are not readily available. Accordingly, the demonstrated performance of existing IGCC power plants serves as a comparison point for the Proposed Action, which is using mature technology for which vendor-guaranteed emission rates are available. Table 8 provides a comparison of the demonstrated performance of IGCC power plants versus the air emissions limits for the Proposed Action.

TABLE 8
Comparison of Demonstrated IGCC Emission Rates

Pollutant	Facility Emissions (lb/MMBtu)			
	TECO (Polk)	Global Energy (Wabash)	LGTI (Destec/Dow)	Proposed Action
SO_2	0.135-0.224[a,d]	0.132-0.266[a,d]	<0.15[g]	0.065-0.09[b]
NO_X	0.09-0.15[a,d]	0.14-0.17[a,d]	<0.26[g]	0.07[b]
PM_{10}	0.013[c,e]	0.012[f]	<0.01[g]	0.015[c]

Notes:
[a] Annual averaging period.
[b] 24-hour averaging period. For SO_2, 0.065 lb/MMBtu corresponds to lower sulfur coals (<0.45% S); 0.09 lb/MMBtu corresponds to higher sulfur coals (≥0.45% S).
[c] 3-hour averaging period.
[d] From U.S. EPA Acid Rain Program data.
[e] Represents air permit limits.
[f] Wabash River Energy, Ltd., "Wabash River Coal Gasification Repowering Project Final Technical Report," August, 2000.
[g] Brown, et al., "An Environmental Assessment of IGCC Power Systems," presented at the Nineteenth Annual Pittsburgh Coal Conference, September 23-27, 2002.

Cost

The cost of an IGCC facility is substantially higher than that of a PC or CFB coal-fired generation facility. AEP has filed for approval of both a 629-MW IGCC facility in West Virginia utilizing eastern bituminous coal and a 616-MW PC facility in Arkansas utilizing Powder River Basin coal. AEP has provided construction cost estimates, excluding carrying costs, of $2.23 billion ($3,545/kW) for the IGCC facility in West Virginia (Waldo, 2007) and $1.343 billion ($2,175/kW) for the PC facility in Arkansas. The capital cost of the IGCC facility is over 60 percent higher than the PC facility.

A recent report prepared by Black & Veatch for Florida Power & Light estimated the engineering, procurement, and construction (EPC) capital costs for an IGCC plant to be 22 to 39 percent higher than a PC facility, and approximately 15 percent higher than a CFB facility (Kobyia, 2006).

IGCC cost estimates are significantly affected by the type of fuel burned. PRB coal, because of the high moisture and lower heat content, would require larger or additional gasifiers to process sufficient fuel for the combustion turbines, and depending on the type of IGCC technology used, the coal might have to be dried prior to gasification, further increasing the costs. PRB coal also has a low fixed carbon ratio, increasing the difficulty of gasification. The low fixed carbon is the reason GE presently will only offer a PRB/petcoke blend gasification system; a 100 percent PRB system is not available.

Also relevant are decisions by regulatory agencies that IGCC technology is not cost effective. Recently, the Minnesota Public Utilities Commission has determined that the pricing provisions of the Mesaba IGCC project proposed in Minnesota "are likely to impose unreasonable and excessive costs on [the utility's] ratepayers" and "carry so many serious risks that the advantages of IGCC technology are not enough to counterbalance them, let alone to tip the scales in favor of contract approval." (Minnesota Public Utilities

Commission 2007). The Administrative Law Judge found that the "power would cost approximately 30 percent more than power from comparable facilities over the life of the contract" resulting in "unreasonably high prices for [the utility] and unreasonably high rates for [the utility's] ratepayers" (Minnesota Public Utilities Commission 2007). Previously, Wisconsin Energy submitted an application to the Wisconsin Public Service Commission to construct a new facility called Elm Road Generating Station (ERGS) consisting of two supercritical pulverized coal units and a single IGCC unit. The Wisconsin Public Service Commission approved both of the PC boilers but denied the IGCC unit. The DNR stated that IGCC was "a different type of process technology" from supercritical pulverized coal, and for this reason, IGCC should not be included in the BACT/LAER analysis for the ERGS (Wisconsin State Court Decision, 2005). Also, SFA Pacific, Inc. in its May 11, 2003 filing to the Illinois EPA, found that for the Prairie State Energy Campus, the costs of producing electricity using an IGCC plant would be 33 percent to 36 percent higher than for the proposed PC plant (SFA Pacific, 2003). The Illinois EPA supported that finding in its issuance of an air permit for construction of PC boilers at the Prairie State Energy Campus (Illinois Environmental Protection Agency, 2005). Finally, the Arizona Corporation Commission stated that "IGCC is not yet a mature, reliable or economic technology alternative for the SGS [Springerville Generating Station]" (Arizona Corporation Commission, 2005).

Commercial Use

IGCC technology has limited commercial experience and is considered a developing technology. IGCC plants currently proposed in the U.S. are seeking some combination of governmental funding and/or special ratemaking rules. In a report released in July 2006, the Environmental Protection Agency stated that development and implementation of the IGCC technology is relatively immature when compared with PC technology (EPA, 2006). IGCC plants are not readily available from equipment vendors with performance guarantees and price certainty. Currently, equipment vendors are requiring interested parties to fund front-end engineering and design studies to make the next generation of IGCC technology available. The studies are expected to aid in the evaluation of performance and cost for a new IGCC, however, proving out this data will require construction and operation of multiple IGCC plants over a multi-year period.

Actions taken by the United States Government reflect the risk associated with projects that employ new or developing technologies. To encourage the advancement and commercial use of gasification technology, Title XVII of the Energy Policy Act of 2005 provides incentives for new or significantly improved technologies as compared to commercial technologies in service in the United States, including IGCC. Subject to an appropriation for the cost, the Act enables the Secretary of Energy may make loan guarantees of up to 80 percent of the cost for an eligible facility if the facility is located in a Western State on a site with elevation greater than 4,000 feet (Title XVII of the Energy Policy Act of 2005, Public Law 109-58, August 8, 2005. 42 USC 16511—16513). Additionally, a facility receiving the loan would be required to meet certain technical requirements and must document an assured revenue stream covering capital and operating costs (including servicing all debt obligations covered by the guarantee). To date, no IGCC facilities have been constructed using these potentially-available funds, and currently, no publicly-announced and active IGCC development projects are seeking these funds.

While an IGCC facility located in White Pine County would meet the minimum elevation requirements for the loan guarantees, this does not imply nor assure the project would receive loan guarantees. In order to receive these incentives, there are other criteria that candidate projects are required to meet, including demonstration of operating on various coal supplies and, importantly, the requirement that the assured revenue stream cover capital and operating costs. The incentives provided for in the Act do not make IGCC a reasonable alternative for the White Pine Energy Station, because the project would still need to overcome the same obstacles as an IGCC project without these incentives to meet the purpose and need of the proposed action.

Conclusion

IGCC technology is alternative considered but not carried forward for detailed analysis in the EIS because it does not meet the purpose and need of the proposed action as summarized below:

- IGCC is still a developing technology. Current IGCC plants are small scale (300 MW or less) and were funded in part with government subsidies. New IGCC plants being proposed are being proposed at up to 600 MW in size, but larger plants are not being considered because of the uncertainties associated with the technology.
- Existing IGCC plants have not achieved the reliability needed for a large, baseload generation facility.
- Existing IGCC plants have efficiency values that are similar to or lower than modern PC plants.
- New IGCC plants are acknowledged to be substantially more expensive to construct, and represent significant commercial risks associated with actual performance (reliability, efficiency, and environmental).
- IGCC has not been proven capable to operate solely on PRB coal, and concerns with this remain on the new generation of IGCC. In addition, the location of the proposed action is not well-situated to other fuel supplies (that is, petcoke, natural gas, or large reserves of bituminous coal).
- If the gasifier at an IGCC plant located in White Pine County failed, there would be no back-up fuel supply to make the project useful since natural gas pipelines are approximately 100 miles from this area.
- Performance of an IGCC at a location in White Pine County would be hindered by the high elevations found in White Pine County, resulting in reduced power production capability of the combustion turbines.

Carbon Capture and Sequestration for IGCC Units

Future regulations on carbon dioxide (CO_2) emissions or other market incentives could potentially require U.S. power plants to capture and sequester emissions of CO_2. In the context of an IGCC unit, "capture" of CO_2 refers to the removal of CO_2 prior to combustion in the combustion turbine. CO_2 that is "sequestered" would be permanently stored in a manner that would prevent the CO_2 from reaching the atmosphere. The combination of carbon capture and sequestration is referred to as "CCS technology."

Carbon Capture

Although carbon capture technology has not been demonstrated in practice for a coal-fueled IGCC unit, (Katzer, James, et al., 2007, p. xiii). CCS technology has the potential to be incorporated into the IGCC process in the future. An IGCC unit equipped with carbon capture (that is, a unit where carbon dioxide, CO_2, is captured for storage and sequestration) would use a process different from that described previously. Applying CO_2 capture to an IGCC unit would require three additional sets of process units downstream of the gasifiers (Katzer, James et al., p. 34):

- Shift reactors
- CO_2 separation process
- CO_2 compression and drying

In the shift reactors, CO in the syngas produced by the gasifiers would be reacted with steam over a catalyst in the presence of heat to produce CO_2 and hydrogen at concentrations of 40 percent and 55 percent, respectively, in the resulting syngas stream (DOE, 2007, p. 18). Facilitated by the high CO_2 concentration and high temperature, CO_2 could be removed from the syngas stream by a variety of physical or chemical processes, such as glycol solvents or membrane separators (DOE, 2007, p. 18). After removal of CO_2 from the syngas, the gas stream sent to the combustion turbine would be primarily predominantly hydrogen, which would require a turbine configuration specifically optimized for hydrogen fuel to achieve efficient operation (Katzer, James, et al., 2007, p. 34). The CO_2 removed from the syngas would be compressed into liquid form and stored prior to being transferred for geologic sequestration or other use such as enhanced oil recovery.

The addition of carbon capture to the design of an IGCC facility would result in significantly higher capital and operating costs, along with lower overall fuel efficiency. Increased capital costs are the result of the additional equipment required for carbon capture and increased infrastructure required to support the carbon capture equipment (for example, water, steam, electrical, piping, etc.). Higher operating costs are associated with increased maintenance requirements and the energy requirements of the carbon capture equipment. Increased energy requirements for carbon capture equipment result primarily because of compressing

the CO_2 to a high-pressure liquid and providing steam for shift reaction (Katzer, James, et al., 2007, pp. 34-35).

Retrofitting an Existing IGCC Plant for Carbon Capture

Retrofitting an IGCC unit for CO_2 capture involves significant changes in the core of the gasification/ combustion/power generation train. The choice of the gasifier (slurry feed, dry feed), gasifier configuration (full-quench, radiant cooling, convective syngas coolers), acid gas clean-up, operating pressure, and gas turbine are dependent on whether a "no-capture" or a "capture" plant is being built (Katzer, James, et al., 2007. p. 38). No-capture designs (that is, IGCC designs that do not incorporate carbon capture) tend to favor lower pressure and increased heat recovery from the gasifier train (radiant coolers and even syngas coolers) to raise more steam for the steam turbine, resulting in a higher net generating efficiency. Dry feed gasifiers provide the highest efficiency and are favored for coals with lower heating value, largely because of their higher moisture content; but the capital costs are higher (Katzer, James, et al., 2007. p. 38).

Capture designs (that is, IGCC designs that incorporate carbon capture) favor higher-pressure operation, slurry feed gasifiers, and full-quench mode. In addition, the design of a high-efficiency combustion turbine for high hydrogen concentration feeds is different from combustion turbines optimized for syngas, requires further development, and has very little operating experience (Katzer, James, et al., 2007. p. 38).

In summary, an optimum IGCC unit design for no CO_2 capture is quite different from an optimum unit design for CO_2 capture (Katzer, James, et al., 2007. p. 38). Nonetheless, it appears that retrofitting a no-capture IGCC unit with carbon capture equipment would be possible, although the resulting system would be expected to be less than optimal in terms of plant efficiency.

Geologic Sequestration

Geologic sequestration involves the injection of captured CO_2 into underground reservoirs that have the ability to securely contain it over long periods of time. The U.S. Department of Energy (DOE) is taking a lead role in advancing the state of sequestration knowledge and technology via its Carbon Sequestration Program. The primary objective of DOE-sponsored research is to develop technologies to cost-effectively store and monitor CO_2 in geologic formations. Accomplishing this involves improved understanding of CO_2 flow and trapping within the reservoir and the development and deployment of technologies such as simulation models and monitoring systems. Experience gained from carbon sequestration field tests will facilitate the development of best practice manuals to ensure that sequestration does not impair the geologic integrity of underground reservoirs, thus assuring secured and environmentally acceptable CO_2 storage.

DOE-sponsored research is concentrated on five types of geologic formations, each presenting unique challenges and opportunities. These formations include oil and gas reservoirs, deep saline formations, un-mineable coal seams, oil and gas rich organic shales, and basalts.

Because of their prevalence worldwide, saline formations may present the highest CO_2 sequestration capacity among the various geologic formation types. There is already one example of demonstrated commercial-scale sequestration in a saline formation. In 1996, prompted by the Norwegian tax on carbon dioxide, the oil company Statoil began taking unwanted carbon dioxide from the Sleipner West field in the Norwegian North Sea and storing it 1,000 meters beneath the seabed in a saline aquifer reservoir. Since 1996, about 1 million metric tons of carbon dioxide per year have been injected into the Utsira saline aquifer (U.S. Energy Information Administration, 2008).

DOE's carbon sequestration atlas suggests that deep saline formations may be present in White Pine County to some extent. Saline formations are composed of porous rock saturated with brine and capped by one or more regionally extensive impermeable rock formations enabling trapping of injected CO_2. Compared to coal seams or oil and gas reservoirs, saline formations are more common and offer the added benefits of greater proximity, higher CO_2 storage capacity, and fewer existing well penetrations. On the other hand, much less is known about the potential of saline formations to store and immobilize CO_2 since each aquifer is unique and not all aquifers will be suitable for sequestration. Additional research will be needed to understand the potential for deep saline formations to store captured CO_2 in White Pine County and elsewhere.

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Appendix A

Classification of Solid Fuels

APPENDIX A

Classification of Solid Fuels

Coal is classified into four main types, or ranks, - lignite, subbituminous, bituminous and anthracite.

Lignite is the lowest rank of coal with the lowest energy content. Approximately 20 lignite mines exist in the United States, producing about 7 percent of U.S. coal with most lignite mined in Texas and North Dakota. Lignite is generally characterized by low heating value and high moisture content making it uneconomical to transport over long distances.

Subbituminous coal has a higher heating value than lignite. Most subbituminous coal in the U.S. is at least 100 million years old. About 42 percent of the coal produced in the United States is subbituminous and is used to generate electricity. Subbituminous is generally characterized by a mid-range heating value, low sulfur content and economical supply making it attractive to transport over long distances. Over the last two decades many power plants have switched to a low sulfur subbituminous coal for environmental compliance. Wyoming is the leading source of subbituminous coal.

Bituminous coal has over twice the heating value of lignite. Bituminous coal was formed under high heat and pressure and in the United States is between 100 to 300 million years old. It is the most abundant rank of coal found in the United States, accounting for about half of U.S. coal production. Bituminous coal is generally characterized by its high heat content, and often higher sulfur and ash content than subbituminous. Bituminous coal is used to generate electricity and is an important fuel and raw material for the steel and iron industries. West Virginia, Kentucky, and Pennsylvania are the largest producers of bituminous coal.

Anthracite contains 86 to 97 percent carbon, and has a heating value slightly lower than bituminous coal. It is very rare in the United States, accounting for less than one-half of a percent of the coal mined in the U.S. Anthracite is used principally for heating homes and in gas production. All of the anthracite mines in the United States are located in northeastern Pennsylvania.

Other Solid Fuels

Waste coal is usable coal refuse that is a byproduct of previous processing operations or is recaptured from mining tailings. Examples include bituminous gob, fine coal, lignite waste, coal recovered from a refuse bank or slurry dam, and coal recovered by dredging.

Petroleum (pet) coke is a byproduct of petroleum refining processes. A residue left over from the refining of crude oil can be further refined by “coking” it at high temperatures and under great pressure. The resulting product is petcoke, a hard substance similar in some respects to coal. Petcoke is generally characterized by its high heat content, high sulfur content and low ash. Approximately 60 to 70 million tons of petcoke are produced worldwide, with most produced at coastal refineries in North and South America.