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INTEGRATED GASIFICATION COMBINED CYCLE TECHNOLOGY IS NOT COMMERCIALLY AVAILABLE OR TECHNICALLY FEASIBLE FOR MEETING THE REQUIREMENTS OF BASIN ELECTRIC POWER COOPERATIVE'S DRY FORK STATION

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SUMMARY OF FINDINGS

Main Findings of This Report

The three main points that I want to convey to the reader of this report are as follows:

1. Integrated Gasification Combined Cycle (IGCC) and Pulverized Coal (PC) are two very different power generation technologies, incorporating very different processes. While PC burns coal in a boiler to make steam for a steam turbine generator, IGCC uses a chemical process that converts the coal to a synthetic gas, which then becomes the fuel used in a gas turbine generator. Substituting IGCC technology for PC technology at Dry Fork Station would be completely redefining the source of power generation technology.

2. IGCC technology is neither commercially available nor technically feasible for meeting the project requirements for Dry Fork Station, as those terms are defined in the New Source Review (NSR) Manual, which provides the guidance for developing the Best Available Control Technology (BACT) evaluation process. IGCC technology suppliers do not commercially offer a 385 megawatt (MW) net IGCC power plant for use with Powder River Basin subbituminous coal, operating at high elevation, and with the ability to provide 95% availability.

3. Even if Basin Electric Power Cooperative were able to purchase IGCC technology for use at Dry Fork Station, it still would not be BACT. The BACT analysis clearly shows that PC technology is BACT for the Dry Fork Station project.

Purpose of the Report and Discussion of Findings

Basin Electric Power Cooperative (BEPC) requested that Integrated Gasification Combined Cycle (IGCC) power generation technology be evaluated for its potential use at the new Dry Fork Station, in lieu of the proven Pulverized Coal (PC) power generation technology that it has selected. Based on my 33 years of experience in the electric power industry, specializing in the permitting, design, construction and operation of PC and IGCC plants, my opinion is that IGCC is not a viable choice and would not meet the critical project requirements for Dry Fork Station. BEPC has selected PC, which is the only power generation technology that can meet the critical project requirements.

While PC is proven at hundreds of installations worldwide, IGCC s still a developing technology that is being demonstrated at only five coal-based units, only two of which are in the U.S. IGCC is not able to meet the critical requirements for Dry Fork Station:

- Providing baseload capacity with high reliability and availability;
- Utilizing commercially available and proven technology; and
- Generating electricity at a reasonable cost.

Baseload capacity is what electric utilities call the generating units that run "24/7", the backbone of the U.S. generating fleet that provides the "base" needs of the customers. These large, efficient power generating units are operated at full load, and are backed up by other, smaller, less efficient units (sometimes called "peakers") that can start up quickly to handle increases in customers needs on cold winter mornings and hot summer days. Together, the baseload units and peakers must follow and satisfy the customers' needs, and do it with high availability.

Why is high availability important? High availability is important for baseload units – they must be available to generate power when called on 24/7 to meet the daily base requirements of the customers. When the availability of a baseload PC unit falls below this level, other baseload units must be called on to pick up the requirements of the customers. This is usually done using smaller, less efficient baseload power generating units, meaning that low availability can directly result in higher cost electricity. Further, smaller and less efficient PC units typically have higher emissions per unit of energy generated. Low availability on a baseload unit then leads to higher overall generating system emissions.

Due to increases in power consumption by BEPC's customers, new baseload capacity is needed. That is the basic business purpose of the new Dry Fork Station, to keep the backbone of power generation strong and meet the needs of BEPC's customers. BEPC selected PC power generation technology to meet this challenge, since it is proven worldwide at doing just that. Other than normal outages for maintenance and repair, PC plants typically operate over 90% of the year. That is called 90% availability. BEPC's existing PC units, such as those at Laramie River Station, have a history of doing just that. The Dry Fork Station is being designed for 95% availability.

BEPC did not select IGCC technology, partly because IGCC cannot yet provide baseload capacity with 95% availability. The five IGCC demonstration plants worldwide have a poor availability record. While they were designed to provide 85% availability, none of them has met that design goal, even after as long as 14 years of operation. None achieves 80% on a consistent basis, and one has rarely reached 60% availability. Even though IGCC technology is not commercially available or technically feasible for the Dry Fork Station, using IGCC would subject BEPC's customers to higher cost electricity, very likely with higher emissions from the other units that would have to pick up generation when the IGCC unit was not operating.

In order to provide 95% availability, BEPC selected the technology that is commercially available and proven to meet the critical requirements for the Dry Fork Station site. PC technology has been proven worldwide for decades, and is commercially available from a number of suppliers. PC technology can be designed for a wide range of site conditions, at sea level or high elevations, and at generating capacities up to over 1,100 MW. Dry Fork Station is being designed to generate 385 MW to match the baseload needs of BEPC's customers.

IGCC technologies are being demonstrated at these five plants at the 250-300 MW size. Based on these demonstrations, the IGCC technology suppliers are commercially offering IGCC technology for full-scale operations, at the size that they call the IGCC "reference plant". It is a standard size of about 600-630 MW (net), based on using eastern bituminous coal, designed for a site at or near sea level. No one has ever built an IGCC plant to use subbituminous coal at a site at high elevation like the Dry Fork Station site. High elevation has significant impacts on IGCC plant performance, reducing the plant's net output by about 13%. These are some of the reasons that IGCC suppliers don't make (or commercially offer) a 385 MW (net) size IGCC unit designed for using subbituminous coal for operation at the high elevation of the Dry Fork Station site.

BEPC and its customers must depend on proven technology that achieves 95% availability. They cannot afford to experiment with developing technologies like IGCC. Dry Fork Station cannot be a technology demonstration or a research & development project that goes on for years to try and see if IGCC can be made to work. The power generation technology for Dry Fork Station must be commercially available and proven to be able to operate efficiently and with 95% availability. <u>PC technology meets that requirement; IGCC does not</u>.

The power generation technology for Dry Fork Station must be able to generate electricity at a reasonable cost. Not only is the capital cost of an IGCC plant much higher (at least 25% more) than a PC plant, its operating and maintenance costs are much higher (about 25-30% more) than a PC plant. Overall, the electricity that an IGCC plant generates is about 20-25% higher in cost than a PC plant. PC technology meets the need for generating electricity at a reasonable cost; IGCC does not.

Conclusion

Unlike IGCC, PC technology is commercially proven and available, and can utilize Powder River Basin subbituminous coal, operate at 4,560 feet elevation, provide the required 95% availability, and generate electricity at a reasonable cost. In selecting PC technology, BEPC has made the only power generation choice for Dry Fork Station.

BASIS FOR EXPERT OPINION

Basin Electric Power Cooperative (BEPC) requested an expert opinion regarding the selection of the best power generation technology to meet the critical project requirements of its new Dry Fork Station. BEPC requested that this opinion compare pulverized coal (PC) technology, which BEPC has selected for Dry Fork Station, with Integrated Gasification Combined Cycle (IGCC), another coal-based power generation technology.

I was requested to make this expert opinion based on my direct, professional experience with both of these technologies. I have 33 years of experience in the power industry, with primary experience in the permitting, design and operation of large PC power plants, emission control systems for PC power plants, and IGCC power plants. I am employed by CH2M HILL, Inc., an international engineering and environmental consulting firm, as Vice President, Gasification Services. Prior to joining CH2M HILL, I was the Gasification Technology Leader for URS Corporation, another international engineering and environmental consulting firm.

Before joining URS Corporation, I worked for Tampa Electric Company over a 25-year period. I worked in a number of areas in the company, including power plant operations, power plant engineering, fuels, environmental permitting, finance, governmental affairs and regulatory affairs. Of most importance to the subject of this report, I served as the Deputy Project Manager for the Polk Power Station IGCC project, one of only two operating coal-based IGCC power plants in the United States. This is where I gained my hands-on experience with IGCC technology.

Since working at the Polk Power Station IGCC plant, I have been directly involved in the permitting of more IGCC and gasification plants than anyone else in the U.S. and was the lead author of the industry's first IGCC Permitting Guidelines Manual, developed for the Electric Power Research Institute's CoalFleet for Tomorrow® Program. In addition to my work at the Polk Power Station IGCC facility, my other IGCC and coal gasification plant experience includes:

- AEP Great Bend (629 MW) – IGCC Technology Lead for air permit application
- AEP Mountaineer (629 MW)– IGCC Technology Lead for air permit application
- Carson Hydrogen Power Project (500 MW) - IGCC Technology Lead for air, water, and waste permitting strategies
- Confidential Client (620 MW) - IGCC Technology Lead for air, water and waste permitting strategies for the conversion of a gas-fired combined cycle unit in Pennsylvania to IGCC technology
- Energy Northwest, Pacific Mountain Energy Center (600 MW) - IGCC Technology Lead for air permit application and state siting documentation
- Excelsior Energy, Mesaba Energy Project (1,212 MW) – IGCC Technical Lead and DOE Liaison for all local, state and federal permitting
- Global Energy, Inc. – Kentucky Pioneer Project (540 MW) – IGCC Technology Lead for air permit application
- Global Energy, Inc. – Lima Energy Project (540 MW) - IGCC Technology Lead for air permit application
- REH – Southeast Idaho Energy – Gasification system air permitting consulting
- Texaco Power & Gasification - Bellefonte IGCC Project (1,600 MW) - IGCC Technology Lead for development of Supplemental Environmental Impact Statement

As part of my career in IGCC and gasification, I have written numerous technical papers and articles, made many presentations, and testified as an expert witness on IGCC and gasification technology. I have provided "Gasification 101" and "IGCC 101" technical presentations to environmental and economic regulatory agencies in the United States and Canada. This includes presentations as part of the Gasification Technologies Council's Regulatory Workshops, and special presentations provided at the request of federal and state agencies, such as those I prepared for the U.S. Environmental Protection Agency (EPA), the Colorado Public Utilities Commission and the Texas Commission on Environmental Quality. Together, I have given my presentations on IGCC technology to over 60 local, state and federal agencies, including the Office of the Governor of Wyoming and the Wyoming Department of Environmental Quality.

I am a proponent of IGCC technology. I believe that IGCC technology has the potential to provide clean, efficient, reliable electricity, and I am involved in many facets of promoting IGCC plant development. I look forward to the wide deployment of IGCC technology, so that this technology can be proven at full scale, and then further developed at larger, more efficient and more cost-effective sizes.

I am also very aware of the limitations of IGCC technology. The recent history of this technology has shown that it has significant limitations in performance, especially with respect to efficiency, availability and cost effectiveness. IGCC technology does not fit everywhere. Specifically, it does not meet the critical project requirements for the Dry Fork Station, which are shown below:

- Providing baseload capacity with 95% availability;
- Utilizing commercially available and proven technology; and
- Generating electricity at a reasonable cost.

As prior power generation technology evaluations prepared by CH2M HILL for BEPC have shown, only PC technology meets all of these critical project requirements. In 2005, CH2M HILL prepared a technical report that compared power generation technologies for use at Dry Fork Station (Exhibit 1). The report included a hypothetical Best Available Control Technology (BACT) analysis that compared the potential changes in emissions if IGCC were to be used in place of PC technology, and the "cost effectiveness" of any potential emission reductions in terms of "$/ton removed", as is commonly determined in the industry as part of a BACT analysis. In that report, CH2M HILL concluded that <u>PC was the most cost-effective</u> and Best Available Control Technology for use at Dry Fork Station. The report also concluded that <u>IGCC technology was not applicable for use at Dry Fork Station</u>, was not cost effective for emission reductions, and did not meet the critical project requirements.

In 2007, CH2M HILL updated that report (Exhibit 2). I contributed to the detailed assessments of PC and IGCC technology as part of the "hypothetical" BACT analysis. That

BACT analysis was, and still is, considered to be hypothetical, since the purpose of a BACT analysis is to select an emission control technology for a proposed power generation technology. PC and IGCC are both power generation technologies, not emission control technologies. However, we developed the hypothetical BACT analyses to determine what the additional costs might be for any incremental reductions that IGCC might be able to achieve. Such a hypothetical BACT analysis would not be required by the U.S. Environmental Protection Agency as part of the air permitting for a new coal-based power plant, and was not required by the Wyoming Department of Environmental Quality as part of the air permitting for the Dry Fork Station project.

As part of providing my expert opinion, it was important to provide further updates to the calculations, given the recent, significant increases in capital costs for industrial facilities, especially with respect to power plants. Further, IGCC technology has suffered from even greater increases in costs. Our updated assessment confirms the conclusions of our prior reports, in that IGCC would not meet the critical project requirements, and it is not a power generation choice for Dry Fork Station. PC technology remains the only choice of power generation technology for Dry Fork Station.

OVERVIEW OF A HYPOTHETICAL BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

As part of developing this report, I have evaluated the differences between PC and IGCC as separate and unique power generation technologies and each one's ability (or lack of ability) to meet the critical project requirements for Dry Fork Station. As part of the air permit application for Dry Fork Station, BEPC provided the required BACT analysis and properly selected the applicable emission control technologies for the PC technology chosen for Dry Fork Station.

While PC and IGCC are power generation technologies, and not emission control technologies, it is possible to evaluate IGCC as part of a "hypothetical" BACT analysis to determine if it would even be technically feasible to substitute IGCC for PC, what the potential emission reductions, if any, might be if substituted for PC, and if those emission reductions would be cost-effective compared to PC. This analysis is considered to be hypothetical, since the U.S. Environmental Protection Agency (EPA) would not require such an evaluation as part of the BACT analysis for a PC power plant. The BACT process is used for selecting emission control technologies; it is not meant for choosing, changing, or redefining the actual source - the power generation technology.

Following are the very important conclusions that result from the requirements of the BACT analysis and the specific definitions provided in the NSR Manual, which provides the guidelines for conducting the BACT analysis:

1. Substituting PC power generation technology with IGCC technology would require a significant and fundamental redefinition of the design of the source of power generation technology. IGCC technology is not something one designs into or adds onto a PC power plant. They are two completely different technologies for generating electricity.

2. As the terms "commercially available" and "technically feasible" are defined and used in the NSR Manual, which provides the guidance for conducting a BACT analysis, IGCC technology is not commercially available or technically feasible for the Dry Fork Station project. IGCC technology suppliers do not make (or commercially offer) a 385 MW (net) IGCC power plant designed to use Powder River Basin subbituminous coal as the feedstock for an IGCC power plant located at a site at an elevation of 4,560 feet and to provide 95% availability. No IGCC power plant has ever been designed or built to generate 385 MW (net) using subbituminous coal, at an elevation of over 4,000 feet. Dry Fork Station must use a commercially proven power generation technology that provides 95% availability, and this project cannot serve as a technology demonstration or a research and development project.

3. Even if IGCC was substituted for the PC technology selected for Dry Fork Station, it still would not be BACT. IGCC is not cost effective compared to PC technology.

THE HYPOTHETICAL BACT ANALYSIS

The NSR Manual

The NSR Manual was developed by the U.S. EPA to provide the guidance for a BACT analysis. The manual is used for selecting emission control systems for a wide range of industrial sources, including power generation technologies. The NSR Manual uses a five step, top down methodology for evaluating add-on emission controls. This methodology is well defined, and provides for a defensible selection or elimination of emission control technologies. The manual uses specific terms which may be defined differently in each step of the process. Therefore, it is important that the definitions be fully understood in order to assess the specific emission control technology appropriately <u>in each step</u> of the process.

The specific terms are listed below, with reference to the page numbers where they occur in the NSR Manual:

- Available (Pages B.5, 17, 18 and 20)
- Practical potential (Page B.5)
- Technically feasible or infeasible (Pages B.7, 17, 19, 20 and 21)
- Applied to full scale development (Page B.11)
- Demonstrated (Pages B.11 and 17)
- Applicable (Pages B.17 and 18)

As part of this hypothetical analysis, it is important to first determine whether IGCC meets each (or any) of these definitions.

1. Is IGCC an <u>available</u> control technology?

    Page B.5 - IGCC is not "available" because it does not to have the practical potential for application at the Dry Fork Station. As noted above, IGCC technology has never been designed or operated using Powder River Basin subbituminous coal at high elevation. Since the IGCC suppliers do not make or commercially offer a 385 MW (net) IGCC power plant (either for eastern bituminous coal or subbituminous coal), and for use at high elevation, BEPC would not be able to even buy such a plant for application to the Dry Fork Station.

Page B.17 - IGCC is not "available" since it cannot be "obtained by the applicant through commercial channels". As noted above, the IGCC suppliers do not make or commercially offer a 385 MW (net) IGCC power plant. When BEPC sent out a Request for Proposals to study the feasibility of installing IGCC technology at Dry Fork Station, they only received three proposals. None of them offered any guarantees or warranties, even though specific guarantees and warranties were requested to be included in the proposals. Without such guarantees or warranties, they could not be considered as real commercial offerings.

Page B.18 – IGCC cannot be considered to be "available" since it has not yet "reached the licensing and commercial sales stage of development" for the needs of Dry Fork Station – a 385 MW (net) power plant with 95% availability, based on using Powder River Basin subbituminous coal, located at a site at an elevation of 4,560 feet, generating electricity at a reasonable cost, and using a commercially proven technology.

Page B.20 – IGCC cannot be considered to have "commercial availability" for the Dry Fork Station project, since no vendor guarantees were offered, even though specific guarantees and warranties were requested to be included in the proposals.

2. Does IGCC have a practical potential to be applied to Dry Fork Station?

Page B.5 – IGCC has no practical potential to be applied at Dry Fork Station. What would be required for Dry Fork Station is not commercially available, and such a configuration has never been designed or operated anywhere. Further, IGCC cannot meet the 95% availability requirement. It would not be practical for IGCC to be installed at Dry Fork Station.

3. Is IGCC technically feasible or infeasible?

Page B.7 – IGCC would not be technically feasible since there would be significant difficulties in designing the plant, and in actually making the plant work, based on physical limitations and engineering principles related to the size of the unit and the impacts of high elevation.

Page B.17 – IGCC is not technically feasible since it has not "been installed and operated successfully on the type of source under review". As noted above, IGCC technology has never been installed and operated successfully using subbituminous coal at high elevation. Further, based on the poor operating history and efficiencies of the longer operating IGCC demonstration plants, IGCC has not even been installed and operated successfully using eastern bituminous coal at or near sea level.

Page B.19 – IGCC is technically infeasible due to its "commercial unavailability" to meet the size, site conditions, elevation and critical project requirements of Dry Fork Station. This is not an issue of cost. As noted above, a request for proposals for an IGCC plant designed for the Dry Fork Station resulted in proposals that could not meet commercial requirements for guarantees and warranties.

Page B.20 – The technical infeasibility of IGCC technology for the Dry Fork Station site has been clearly described above. The "unresolvable technical difficulties would preclude the successful development" of an IGCC plant that needs to be designed at the 385 MW (net) size, using subbituminous coal, located at an elevation of 4,560 feet, with a requirement for baseload operation with 95% availability.

Page B.21 – IGCC is not technically feasible since all of the information noted above clearly shows that "source-specific factors exist and are documented to justify the technical infeasibility" of IGCC technology at Dry Fork Station.

4. Has IGCC been <u>applied for full scale development</u>?

Page B.11 – IGCC technology has not yet been applied for full-scale development. IGCC has only been demonstrated at small scale, at the 250-300 MW (net) size. IGCC technology suppliers are now commercially offering the full-scale IGCC reference plant described above, at the 600 -630 MW (net) size. It will be five to six years before full-scale plants have been constructed and started up.

5. Is IGCC demonstrated?

Page B.11 – IGCC has not been successfully demonstrated in practice on full scale operations. It has only been demonstrated at small scale, as noted above, and even those demonstrations cannot be considered to be successful since the plants have not met their design goals.

Page B.17 – IGCC is not yet demonstrated since it has not "operated successfully on the type of source under review", meaning a 385 MW (net) IGCC plant using Powder River Basin subbituminous coal, located on a site at an elevation of 4,560 feet, and providing baseload electrical generating capacity with 95% availability.

6. Is IGCC applicable?

Page B.17 – IGCC is not applicable since it cannot "reasonably be installed and operated on the source type under consideration", meaning a 385 MW (net) power plant designed to use subbituminous coal, operate on a site located at an elevation of 4,560 feet, and provide baseload capacity with 95% availability using a commercially available and proven power generation technology.

STEP 1 OF THE BACT ANALYSIS

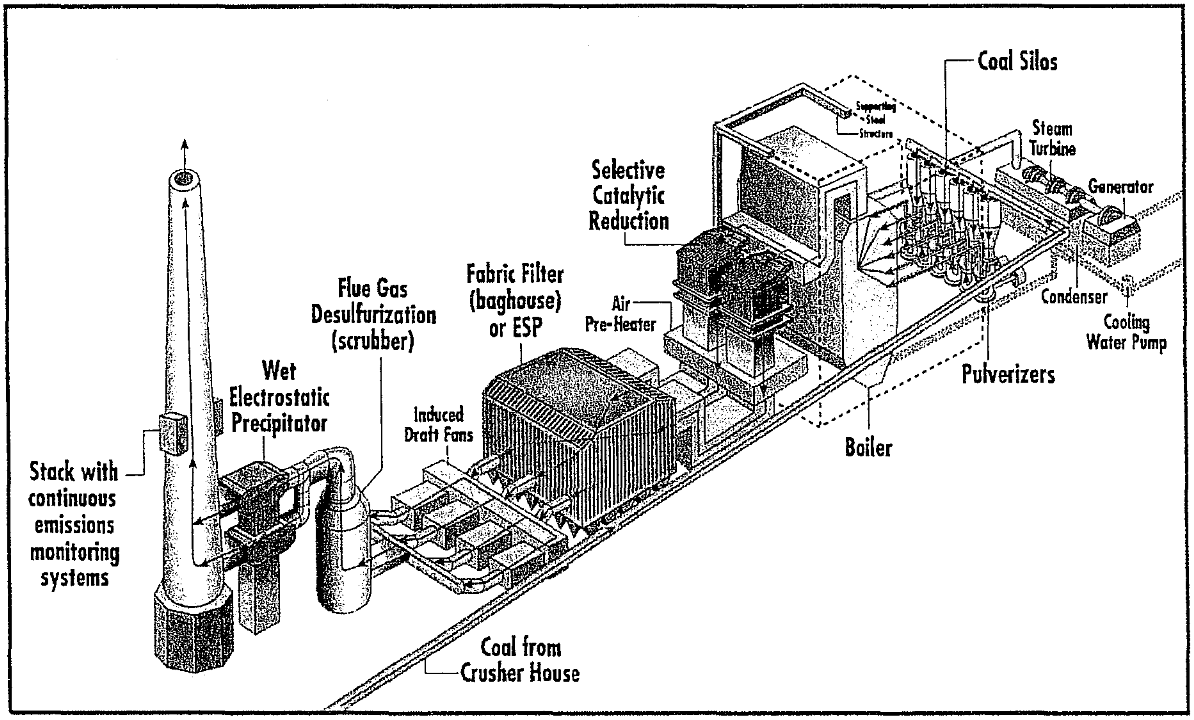
1. Would the use of IGCC technology instead of PC technology constitute a redefinition or redesign of the proposed PC technology?

The purpose of a BACT analysis is to evaluate various emission control technologies that can be applied to the power generation source that has been selected for a specific project. The purpose of the BACT analysis is not to evaluate or select the actual source of power generation technology. The power generation technology is selected prior to performing the BACT analysis, using project-specific and site-specific parameters. For this project, BEPC selected PC technology to meet its critical project requirements, and it has evaluated and selected specific emission control technologies for use with that PC technology.

Changing from PC technology to IGCC technology would be a significant and fundamental redefinition of the design of the source for Dry Fork Station. In order for the reader to fully understand this, it is important to understand the differences between PC and IGCC technologies. Following is a basic description of these two unique power generation technologies.

WHAT IS PC TECHNOLOGY?

PC technology, which is proven at hundreds of installations world-wide at large commercial scale, involves the combustion of coal to produce steam, which is then used to drive a steam turbine generator to generate electricity. After exiting the steam turbine, the steam is condensed to water, and then pumped back to the boiler to be turned into steam again. The figure below shows the major systems in a PC power plant.



Source: Florida Power & Light

The use of steam produced in a boiler and used to drive a steam turbine-generator is called the Rankine thermodynamic cycle. With PC technology, the coal is first crushed and pulverized to a fine powder, then blown into the boiler with air. The combustion of coal occurs in a range of 2,500-3,000 °F, producing exhaust gases made up primarily of carbon dioxide ("CO_2"), nitrogen and water. It is important to clarify that in a PC boiler, the coal is the fuel. Some of the nitrogen in the coal, as well as the nitrogen in the air, is converted to oxides of nitrogen (NOx). Ash in the coal is converted either to fly ash, which exits with the exhaust gases, or bottom ash, which is extracted from the bottom of the boiler's furnace.

The flue gases from the coal combustion process then leave the boiler and pass through emission control systems. Typically, the first emission control system is the selective catalytic reduction ("SCR") system, for NOx reduction. The flue gas then enters the air preheater, which transfers heat from the flue gases to the incoming combustion air, increasing the overall plant efficiency. Following that, the flue gases pass through a fabric filter (baghouse) or electrostatic precipitator, where more than 99% of the fly ash is removed. The flue gases then flow into the flue gas desulfurization ("FGD") system, where sulfur dioxide ("SO_2") is absorbed. If a dry FGD system is used (as with the Dry Fork Station configuration), the baghouse follows it, so that the fly ash and the SO_2 reaction byproducts can be removed in one step. From there, the cooled, clean flue gases exit through the stack.

WHAT IS IGCC TECHNOLOGY?

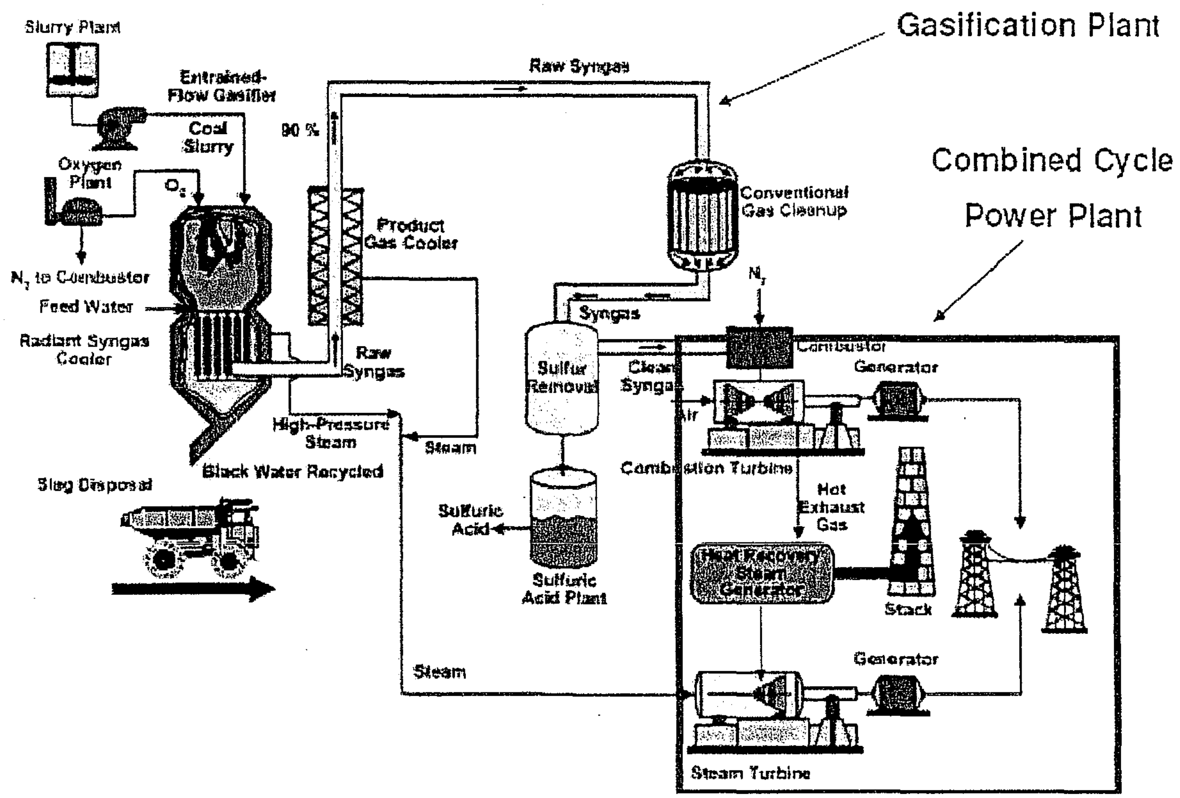
IGCC is a developing technology for generating electricity using a synthetic gas produced from coal. It is considered a developing technology, since there are only five demonstration-sized, coal-based IGCC plants worldwide, versus hundreds of commercial-scale PC plants as noted above. IGCC uses coal very differently from PC technology. As noted above, coal is the fuel for a PC boiler – it is actually burned with a flame. However, in an IGCC plant, the coal is not a fuel, and the coal itself is not burned. In an IGCC plant, the coal is simply a feedstock for a chemical process that creates a synthetic gas.

IGCC is a combination of coal gasification technology from the chemical industry and combined cycle technology from the power industry. Understanding each of these two technologies and how they are integrated into one facility for generating electricity is important.

Coal gasification is a process whereby carbon-based materials, like coal, are converted at high temperature and high pressure, and with a limited amount of air or oxygen, into a synthetic gas, called "syngas". This syngas is composed primarily of carbon monoxide and hydrogen, which are combustible gases, although they are also used in the chemicals industry as basic building blocks for a wide range of chemicals and fuels. The syngas can be combusted for use in generating electricity. Coal gasification is very different from the combustion that occurs in a boiler. PC boilers require excess air to ensure that the coal is completely combusted, while gasification operates in an oxygen-starved environment, so that complete combustion is precluded. Gasification has been in use worldwide for over 200 years, initially for converting coal to town gas for use in heating and lighting, and later for the production of chemicals and transportation fuels. Coal gasification itself is not a method for generating electricity, but is a chemical process used to produce the syngas.

Combined cycle power generation technology uses a combination of two unique methods of power generation. The first is the Brayton thermodynamic cycle, where gas turbines combust natural gas or diesel oil as the primary fuel. The gas turbine operates like a jet engine, and rotates at a high rate of speed. It is connected on the same shaft to a generator, so that the mechanical energy is converted to electrical energy. The exhaust gases leave the gas turbine at a temperature over 1,000°F. This hot exhaust gas flows through a boiler, called a heat recovery steam generator ("HRSG"), which uses the hot exhaust gas to produce steam. This steam is piped to a steam turbine generator to generate additional electricity. By capturing the energy in the exhaust gas, the output and efficiency of the overall power plant are increased substantially.

An IGCC facility combines coal gasification technology from the chemical industry with combined cycle power generation technology from the power industry. The figure below shows how this combination of coal gasification and combined cycle technologies is integrated into the power generation technology we call IGCC.



Source: U.S. Department of Energy

Air, steam, oxygen, nitrogen and other streams are integrated between the gasification and combined cycle "islands"; hence, the name Integrated Gasification Combined Cycle, or IGCC. The integration part of IGCC provides a great challenge in the design and during operation. It involves combining coal gasification and power generation technologies, as well as additional systems that are required to monitor and control the overall process.

Conclusion

As noted above, PC and IGCC are two very different power generation technologies, incorporating very different processes. While PC combusts coal in a boiler to make steam, IGCC converts coal to a synthetic gas, which is then used in a gas turbine.

Other than the coal handling and storage equipment and a main station transformer for connecting the plant to the electrical grid, almost everything else in between the "coal in" and "power out" points is completely different for these two power generation technologies and there are few pieces of equipment or systems that are similar or interchangeable.

On that basis, changing from PC technology to IGCC technology would require a significant and fundamental redefinition of the design of the PC power generation technology that has been selected for Dry Fork Station.

2. Would the use of IGCC technology satisfy the critical project requirements for the Dry Fork project?

IGCC would not meet the critical project requirements for Dry Fork Station, which are:

- Providing baseload capacity with 95% availability;
- Utilizing commercially available and proven technology; and
- Generating electricity at a reasonable cost.

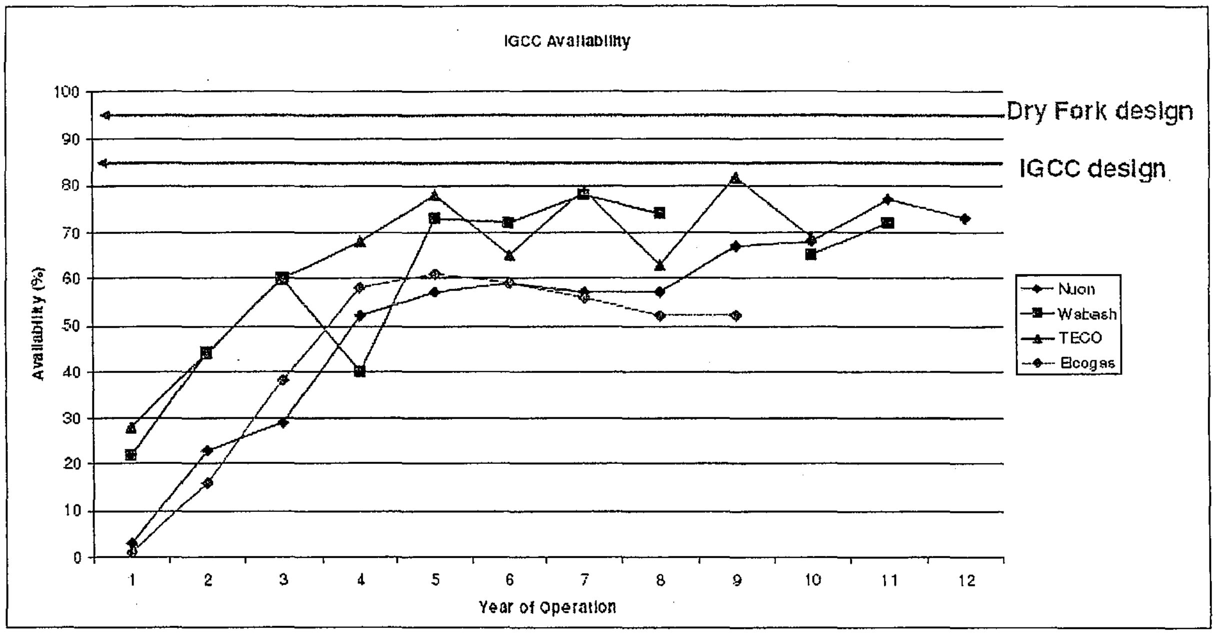
PC technology was selected as the power generation technology for the Dry Fork Station project because it meets all of the critical project requirements. PC technology is proven worldwide in hundreds of installations. Using IGCC technology would not satisfy the basic business purpose and objectives of the Dry Fork Station project. An assessment of the ability of IGCC to meet each of the critical project requirements is provided below.

a. Can IGCC technology provide the 95% availability required for the Dry Fork Station project?

IGCC has only been demonstrated at relatively small-scale operations, and at only five coal-based plants worldwide, the oldest of which has been in operation about 14 years. Two are in the United States, one is in the Netherlands, one is in Spain, and the most recent demonstration plant started up last fall in Japan. All five are referred to as "demonstration" plants, as each was built to demonstrate the first application of a specific IGCC technology at a nominal 250-300 MW size, using one gasifier train with a power block composed of one gas turbine, one HRSG and one steam turbine.

None of these plants has been able to provide even close to 95% availability. As the figure below shows, none of the four initial IGCC demonstration plants has achieved even 80% operational availability on a consistent basis. One has barely been able to achieve 60%

availability. These IGCC demonstration plants have not been able to meet their individual project-specific goals of 85% availability. Based on that performance, and the fact that the IGCC reference plant designs (for the plants to be started up in 2011-2014) are expected to provide only as high as 86% availability, IGCC would not be able to meet the 95% availability requirement for Dry Fork Station.



Source: Electric Power Research Institute

Tampa Electric's Polk Power Station Unit #1 IGCC facility was designed to meet an 85% availability goal in the second year of operation[1]. As the graph shows, the availability in the second year was only 45%, and it has never achieved 85% availability in its more than 11 years of operation. It barely meets 80% availability on a consistent basis. Even with the thousands of lessons learned at Polk Power Station Unit #1, Tampa Electric noted in the application to the State of Florida for its proposed new Polk Power Station Unit #6 (now cancelled), that it would only achieve 86% availability[2]. Even at 86% availability, IGCC technology would not be able to meet the critical project requirements for Dry Fork Station.

This is in comparison to PC technology, which has been successfully demonstrated in service at hundreds of full scale units for decades. PC technology has achieved over 90%

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1 "Final Public Design Report", Tampa Electric Company, July 1996.

2 "Testimony and Exhibits of Michael R. Rivers", Tampa Electric's Petition to Determine the Need for Polk Power Plant Unit 6, July 2007.

operational availability on a consistent basis. BEPC's own PC units, such as the three units at the Laramie River Station, have achieved an average availability of greater than 90% over the past six years.

IGCC is not yet able to provide baseload capacity with high reliability and availability.

b. Is IGCC technology a commercially available and proven technology?

IGCC technology is not a commercially available and proven technology for the project requirements for the Dry Fork Station. It is not commercially available at the 385 MW (net) size needed for Dry Fork Station. As noted previously, IGCC technology suppliers are now offering their technologies for use in commercial power plants. These commercial offerings are based on the use of a two-gasifier train configuration, with each gasifier designed to produce sufficient syngas to fully load a modern "FB" class gas turbine. The gas turbine is then matched with a steam turbine generator designed to utilize the steam produced in the HRSGs and in the syngas coolers (if used) in the gasification island. The commercial IGCC offerings are based on the plant being designed for bituminous coal, and operating at or near sea level. This "IGCC reference plant" is typically sized to generate approximately 600-630 MW (net) at these conditions.

While many of the components of an IGCC plant have been proven in commercial service, the operating history of the demonstration plants has clearly shown that IGCC is not yet a proven technology for full-scale, baseload power generation. It is still a developing technology.

One of the performance expectations of IGCC was that it would be much more efficient than PC technology. That has not been the case, and IGCC has been unsuccessful in meeting that performance expectation. For example, Tampa Electric Company's Polk Power Station IGCC Unit #1 was designed for a heat rate of 8,500 Btu/kWh, which is an efficiency of 40%. Tampa Electric has reported that the plant's normal operating heat is 9,600 Btu/kWh, or an efficiency of only 35.5%. On an annual basis, the startups and shutdowns increase the heat rate to as high as 10,140 Btu/kWh, or an efficiency of only 33.6%.

It will be another six to seven years before the proposed "full scale" IGCC reference plants will have been constructed, have been started up, have gone through initial operation, and have been in stable operation for at least one to two years. Only at that time will it be possible to determine whether IGCC technology has been successfully demonstrated on full scale operations. For now, IGCC is not proven on full-scale operations.

c. Can IGCC technology generate electricity at a reasonable cost?

As discussed above, IGCC is not even commercially available at the 385 MW (net) size needed for Dry Fork Station. Even if BEPC could buy IGCC technology at that size, and designed to meet the critical project requirements for Dry Fork Station, it would cost BEPC's customers much more than for PC technology. Over the past several years, the industry has seen a significant escalation in the capital cost of power plants. This is highlighted in a recent report by Cambridge Energy Research Associates (CERA), providing the increases in power plants costs since 2000[3].

Increases in power plant capital costs, along with fuel and O&M costs, directly impact the cost of electricity. Industry data has been consistent in showing that IGCC is significantly higher in capital cost than PC technology.

As an example, GE Energy noted that IGCC technology costs 20-25% more than PC technology[4], and that they expected to be able to cut that premium in half. That has not occurred. IGCC capital costs have continued to escalate. Some of the most up-to-date IGCC cost data have been provided by Duke Energy Indiana for its proposed 795 MW gross/630 MW net Edwardsport IGCC project. In 2007, Duke Energy had reported the cost of this IGCC plant (a GE energy IGCC plant designed for eastern bituminous coal) to be $1.985 billion[5]. In April, 2008, Duke Energy notified the Indiana Utility Regulatory Commission that the cost estimate had increased another $365 million[6], or 18%, to $2.35 billion, or $3,730/kW. Such increases in capital cost will continue to have an impact on the cost of

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[3] http://www.cera.com/aspx/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=9505

[4] "GE's Gasification Developments", Ed Lowe, GE Energy. October, 2005.

[5] "Edwardsport Integrated Gasification Combined Cycle Power Station – Front End Engineering and Design Study Report", filed with the Indiana Utility Regulatory Commission, April, 2007.

[6] "Petitioner's Case-in-Chief Testimony and Exhibits of James L. Turner", filed by Duke Energy Indiana with the Indiana Utility Regulatory Commission, May 16, 2008.

electricity from IGCC power plants. Duke Energy is also building its 800 MW (net) Cliffside PC unit in North Carolina. The cost of that unit is estimated to be $1.8 billion, plus another $600 million in interest during construction, for a total of $2.4 billion[7]. This would be $3,000/kW. On that basis, Duke Energy's IGCC plant will be 24% higher in capital cost than its PC plant.

The U.S. Department of Energy (DOE) published its most recent (2007) detailed technical and economic cost data in a report titled "Cost and Performance Baseline for Fossil Energy Plants". The report provides the cost of electricity generated by various power generation technologies. For PC and IGCC, the costs are based on the use of bituminous coal:

	IGCC	PC
Cost of Electricity, c/kWh	7.80	6.40

IGCC costs are based on GE Energy technology

This DOE report shows that the cost of the same electricity from IGCC would be 22% higher than from a PC unit. Another example of the higher cost of electricity from IGCC plants is for the proposed Mesaba IGCC project in Minnesota. As part of the administrative hearings for this case before the Minnesota Public Utilities Commission, the Administrative Law Judges assigned to the case found that the cost of the electricity from this plant would be 32% higher than that from a proposed nearby PC plant[8].

Based on these recent cost estimates, <u>IGCC is not able to generate electricity at a reasonable cost</u>.

Conclusion

While PC technology meets all of the project requirements, IGCC does not. Based on this evaluation, IGCC technology does not satisfy the critical project requirements for a

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[7] "February 2008 Advanced Clean Coal Cliffside Unit 6 Cost Estimate, Docket No. E-7, Sub 790", letter from counsel to Duke Energy Carolinas to the North Carolina Utilities Commission, February 29, 2008.

[8] "Findings of Fact, Conclusions of Law, and Recommendation", MPUC Docket No. E-6472/M-05-11993 and OAH Docket 12-2500-17260-2. April, 2007.

commercially proven power generation technology that can provide reasonably-priced electricity with 95% availability for the Dry Fork Station project.

3. Has IGCC technology been successfully demonstrated on full scale commercial operations?

According to the NSR Manual, an "available" technology is one that has been "successfully demonstrated in practice on full scale operations". As noted above, IGCC demonstration plants have not been successful in achieving either availability or efficiency design goals. Further, IGCC technology only exists at the demonstration size. It will be several years before the full-scale IGCC plants will be in operation.

IGCC cannot be considered as "available" based on this definition in the NSR Manual, because it has not been successfully demonstrated on full-scale operations. It is still a developing technology, and is not yet considered to be proven at full scale. That conclusion is further confirmed by the construction of another IGCC technology demonstration plant, such as the Nakoso plant in Japan, which only recently began operation.

STEP 2 OF THE BACT ANALYSIS

Step 2 is for determining the technical feasibility of emission control options that were identified in Step 1. Although IGCC has been eliminated from further consideration in Step 1 of the BACT analysis, it will be evaluated under Step 2 of this hypothetical BACT analysis. According to the NSR Manual, an emission control option that has been demonstrated is considered to be technically feasible. Emission control options that have not been demonstrated are assumed to be technically feasible if they are commercially available and can reasonably be installed and operated on the source.

1. Has IGCC technology been installed and operated successfully on projects like the Dry Fork Project?

IGCC technology has never been installed or operated successfully on any projects like the Dry Fork Station project. The Dry Fork Station project presents a technical challenge to IGCC technology, in that the design coal is subbituminous coal from the Powder River Basin, the plant will be located at an elevation of 4,560 feet, and with a requirement for 95%

availability. The GE Energy (then Texaco) technology used at Tampa Electric Company's Polk Power Station was designed for eastern bituminous coal. It presently uses blends of bituminous coal and pet coke. The ConocoPhillips (then Destec) technology used at the Wabash River Plant was designed for local bituminous Indiana coals. In order to lower generation costs, it presently uses up to 100% pet coke as the feedstock.

Another key design feature of all of the IGCC demonstration projects is that they were designed to operate at sea level or low elevation. There are no IGCC plants operating at high elevation. Throughout the western U.S., there are many PC plants that have been successfully built and operated with subbituminous coal at high elevation, as there are minimal elevation impacts on PC technology. However, IGCC technology has technical limitations due to high elevation.

At high elevations, such as at the Dry Fork Station site, the impacts of high elevation would be substantial, resulting in a reduction in net plant output of 13% (see calculations later in this report). At higher elevations, where the air is less dense, gas turbines are unable to compress sufficient amounts of air through their combustion systems. The impact of this restriction is that the amount of syngas that can be combusted (with the lower amount of air available) is reduced, and gas turbine power output is reduced. Since less syngas is used, the coal throughput is also reduced. Since less coal is used, the amount of oxygen required is also reduced, and the capacity of the air separation unit is reduced. Since commercial gasifiers and gas turbines are designed and rated at sea level conditions, the plant's output would be reduced to a point where more than 10% of the plant equipments capacity would go unused. This means that the millions of dollars spent for such equipment would have to be spread over the lesser amount of power generated at the plant, making electricity from an IGCC power plant even more expensive than from a PC plant.

Conclusion

For these reasons, no IGCC plants have been built at high elevation. More specifically, no IGCC plants have been installed or successfully operated at the conditions of the Dry Fork Station.

2. Is IGCC technology commercially available for the Dry Fork Project?

IGCC technology is not commercially available for the 385 MW (net) size and for meeting the critical project requirements for the Dry Fork Station. IGCC technology is commercially offered as a standard "reference plant", based primarily on the use of eastern bituminous coal, at sea level or low elevation. For example, GE Energy, a leader in the IGCC industry, does not offer its IGCC technology for use with subbituminous coal, so that it would not be considered for this project at all.

However, IGCC technology is <u>not commercially available</u> at the 385 MW (net) size needed for the Dry Fork Station. IGCC technology suppliers have demonstrated (although not successfully demonstrated, as history shows) their technologies at the 250-300 MW (net) size, using a configuration with one gasifier, one gas turbine, one HRSG and one steam turbine. This one gasifier train configuration was designed only for demonstration purposes, and is not offered commercially.

Today, IGCC technology suppliers are commercially offering an IGCC "reference plant" that uses two 50%-sized gasifiers to produce sufficient syngas to fully load two FB-class gas turbines, with two HRSGs and a steam turbine rated to use the steam from the HRSGs and syngas coolers in the gasification block for power generation. This reference plant configuration would generate 770-795 MW (gross) and 600-630 MW (net), using eastern bituminous coal as the feedstock, and operating at sea level.

The IGCC reference plant's approximate output is as follows:

Gas turbine gross output:	464 MW
Steam turbine gross output:	+ <u>320 MW</u>
Total gross output:	**784 MW**
Internal load:	<u>-150 MW</u>
Net plant output	**630 MW**

This is the basis of the reference plant that is commercially available from several IGCC technology suppliers. This would not meet the critical project requirements for Dry Fork Station. These IGCC technology suppliers do not commercially offer the "one gasifier train" demonstration plant design, as that was only for demonstration plant purposes. What is commercially offered is the two gasifier configuration described above. The gas turbines are manufactured and commercially offered in a fixed size. In order to fully load these gas turbines, the gasification technology manufacturers have designed their gasifiers to a matching size. The overall implication of this is that IGCC power plants are commercially offered to generate about 630 MW net. Not 250 MW net, as in the demonstration plants, and not 385 MW net as with the project requirements for the Dry Fork Station. The 385 MW net size of IGCC plant is not commercially offered.

Conclusion

Therefore, IGCC technology is not commercially available for application at Dry Fork Station.

3. Is IGCC technology demonstrated to be applicable to projects like Dry Fork – can it be reasonably installed and operated at Dry Fork Station?

IGCC technology has not been demonstrated to be applicable to projects like Dry Fork Station. It cannot be reasonably installed and operated at the site conditions and to meet the critical project requirements for Dry Fork Station. This issue deals primarily with whether IGCC can be installed and operated at Dry Fork Station, using subbituminous coal at high elevation, and meeting 95% availability. Even though a 385 MW net size IGCC plant is not commercially available, this report evaluates whether such a plant could be reasonably operated at the Dry Fork Station site.

In a recent detailed study by ConocoPhillips (an IGCC technology supplier) and WorleyParsons (an engineering company)[9], the impacts of elevation were determined for an IGCC plant at sea level and one at over 4,000 feet altitude. The study was based on the commercial IGCC reference plant described above. In the table below, the column "Impact of Elevation" provides the results of the study. The base values for the IGCC plant at sea level are from a study performed by ConocoPhillips in 2006[10]. The values at the 4,000- foot level (similar to the Dry Fork Station site) are calculated from the per cent reduction values presented in the study.

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[9] "CO_2 Capture: Impacts on IGCC Plant Performance in a High Elevation Application using Western Sub-bituminous Coal", Satish Gadde and Jay White (WorleyParsons) and Ron Herbanek and Jayesh Shah (ConocoPhillips), October, 2007.

[10] "E-Gas Applications for Sub-Bituminous Coal", Ron Herbanek and Thomas A. Lynch, ConocoPhillips, October, 2005.

Gross plant output, MW	IGCC plant at sea level	Impact of 4,000 foot elevation	IGCC plant at 4,000'
Gas turbine	464	-9%	422
Steam turbine	314	-16%	263
Total gross output, MW	778	-12%	685
Total aux loads and losses, MW	134	-8%	123
Net power output, MW	644	-13%	561

This study shows that high elevation does have a significant impact on IGCC technology and its performance. The reference plant (for this study, the reference plant was sized at 644 MW) would experience a reduction in power output to only 561 MW. This is an overall reduction in plant output of 83 MW, or 13%. This shows that there would be a significant performance impact on an IGCC plant due to the high elevation of the Dry Fork site. While some components of the gasification island would be smaller, since less coal would be gasified, some portions of the IGCC plant would remain at the same size. The gas turbines are a standard factory size, and would operate at below their maximum rated output due to the less dense air. The steam turbine, which would be 16% smaller as shown in the table above, could be manufactured at a size closer to that lower capacity.

Conclusion

It would not be reasonable or cost effective to select a power generation technology that would suffer such a performance impact. Since the 385 MW net size is not commercially available, IGCC technology could not be installed at the Dry Fork Station. Due to the significant impacts on performance, IGCC technology could not be reasonably operated at the Dry Fork Station site.

4. Has IGCC technology reached the licensing and commercial sales stage of development for a project with the needs and attributes of Dry Fork Station?

Conclusion

As noted above, IGCC technology is not commercially available at the 385 MW (net) size, for use with subbituminous coal, at the high elevation of the Dry Fork Station site. It is not yet developed to the stage where it would meet the Dry Fork Station project requirements for generating baseload capacity with 95% availability, and using a commercially proven technology.

STEP 4 OF THE BACT ANALYSIS

Step 4 of the BACT analysis is used to evaluate the energy, environmental, and economic impacts of each of the emission control technologies that have "survived" the prior assessment steps. While IGCC technology has been eliminated in the steps shown above, it is still valuable to show that IGCC is not a cost effective technology for reducing emissions, compared to the PC technology that has been selected for Dry Fork Station.

1. What is the incremental cost-effectiveness of IGCC technology, compared with PC technology, in reducing emissions--what is the cost per ton of additional pollutants removed?

Conclusion

Using the most current and reliable capital, O&M and fuel costs, as well as environmental performance that is applicable to PC and IGCC plants, the cost effectiveness values have been calculated (as shown later in this report), for changing from PC to IGCC technology (even though IGCC technology was eliminated from each of the BACT steps as shown above). The value for the overall incremental reductions in emissions is $26,400/ton, which is far above any cost effective values used to make alternate selections for emission control systems.

ASSESSMENT OF THE CLEAN AIR TASK FORCE REPORT

In April, 2008, Mr. Mike Fowler of the Clean Air Task Force submitted his report "Expert Report on Integrated Gasification Combined Cycle and Pulverized Coal Combustion in the Best Available Control Technology Analysis for the Dry Fork Station Power Plant". His report was prepared on behalf of the Powder River Basin Resources Council, in support of their contention that IGCC technology should be selected as BACT for the Dry Fork Station project. The report makes conclusions that IGCC is cost-effective, commercially available at the size for the Dry Fork Station, has high availability, and should be selected as BACT for Dry Fork Station.

A detailed review of the report shows that those conclusions were based on the use of flawed assumptions, old and underestimated IGCC costs, inappropriate emission rate data, and incorrect values for IGCC demonstration plant performance, heat rate and availability. Following is an analysis of that report, noting the specific errors which were made, and how using the correct information would have resulted in Mr. Fowler's analysis reaching the same conclusions as presented in CH2M HILL's 2005 and 2007 technology evaluations and in this report:

- Changing from PC technology to IGCC technology would be redefining the source of power generation;
- IGCC is not commercially available or technically feasible, according to the definitions of these terms in the NSR Manual; and
- Even if IGCC technology could be purchased, it would not be BACT for the Dry Fork Station project.

The following analysis references the specific page numbers and sections from Mr. Fowler's report.

Page 2, Section III. Summary of Methods and Findings.

Mr. Fowler states that his evaluation is based on "the author's experience and judgment". He included his resume as Exhibit I to his report. A review of the resume shows that Mr. Fowler has been in his present position relating to "fossil fuel combustion, coal gasification, and carbon dioxide capture and geological sequestration" <u>for only 15 months</u>. Nowhere in his resume does it show that he has any experience with the design, construction or operation of either IGCC or PC plants.

Page 5. IGCC's Practical Potential for Emissions Control

Mr. Fowler makes the statement "Although the details of the electric production process differ in some respects, IGCC and PC plants share many similarities...". In fact, these two power generation technologies differ in almost all respects.

PC is a completely different power generation technology than IGCC, based on completely different design and operating concepts. In a PC plant (which is based on the Rankine thermodynamic cycle), coal is a fuel; it is combusted in a boiler, and steam is produced. The steam turns a steam turbine generator, producing electricity. In an IGCC plant, the coal is a feedstock for a chemical process, where it is thermally converted into a synthetic gas. It is this synthetic gas, or syngas, which is then used in a gas turbine in the separate power island. IGCC is based on the use of the Brayton thermodynamic cycle (gas turbines) for primary power production, with steam produced in the plant used in a separate steam turbine. While both PC and IGCC plants have coal handling and storage equipment and a main station transformer for connecting the plant to the electrical grid, almost everything else in between the "coal in" and "power out" points is different, and there are few pieces of equipment or systems that are similar or interchangeable. These two technologies differ in almost all respects, not "in some respects" as Mr. Fowler notes.

This is important because PC and IGCC are not similar technologies, and an expert in power generation technologies would not consider PC and IGCC as being similar or interchangeable.

Page 6. IGCC's Practical Potential for Emissions Control

Mr. Fowler states that "the heat from the gasification process is used to produce steam and generate electricity using steam turbine generator sets just as in a PC plant." What Mr. Fowler fails to note is that in a PC plant, 100% of the power comes from the steam turbine generator. In an IGCC plant, about 60% of the power comes from the gas turbine generators, with only 40% coming from the steam turbine generator. IGCC steam production does not come from capturing heat from the direct combustion of coal in a boiler as it does in a PC plant, but from capturing waste heat from the combustion of syngas in gas turbines and from syngas coolers in the gasification portion of the plant. Power generation in an IGCC plant does not occur "just as in a PC plant".

This is important because a power generation technology expert would fully understand these major differences between PC and IGCC technology.

Page 6. IGCC's Practical Potential for Emissions Control

Mr. Fowler states that "IGCC is not a new technology." Actually, IGCC is a rather new technology. While many aspects of an IGCC plant have been proven in service for decades, the integration and use of these systems and components for power generation has only been demonstrated on five plants worldwide, and only over the last 14 years. While IGCC has been demonstrated at these plants, its history of meeting design targets for efficiency and availability has been poor. This is why IGCC still needs to be developed and proven at full scale.

Mr. Fowler also refers to the 417 gasifiers at the 138 gasification plants worldwide and notes the various feedstocks that they use. Only five of those plants are coal-based IGCC plants. The other gasification plants, many of which use liquid refinery wastes as feedstocks, are primarily for producing chemicals, hydrogen, steam, and transportation fuels, but not electricity. The business purposes, design conditions, feedstocks and site conditions are different from those of the Dry Fork Station project. Just because there are 417 gasifiers worldwide in no way implies that gasification technology, when incorporated as part of an IGCC plant, is commercially available or applicable for use at Dry Fork Station, or would be able to meet its needs for generating 385 MW (net) using Powder River Basin subbituminous coal as a feedstock, operating at 4,560 feet elevation, and providing 95% availability.

This is important because it is incorrect to state or assume that just because gasification technology is used in any number of plants worldwide, that IGCC technology can be used at Dry Fork Station and meet its critical project requirements.

Pages 6-7. Table 1-1

Mr. Fowler includes liquid feedstock-based IGCC plants in his list of IGCC plants. It is inappropriate to compare liquid feedstock-based IGCC plants to coal-based IGCC plants. The design of an IGCC plant using solid feedstocks such as coal is very different from one designed for gasifying liquid feedstocks. There are many additional design issues that must be addressed when using coal as the feedstock. They include:

1. A coal delivery, storage and handling system is required for coal. Such solids handling systems are not needed for liquid feedstocks.

2. Coal contains a significant portion of ash, often up to 15%, whereas liquid feedstocks typically have almost no ash content. When using coal, the ash is converted to molten slag, and the gasifier must be designed to operate at temperatures that keep the slag in molten form, so that it can readily flow from the bottom of the gasifier by gravity. The gasifier refractory must be designed for the chemical components of the slag, and the slag handling and removal systems must be designed for the large amount of ash and slag. These design considerations are not required for gasifiers using liquid feedstocks.

3. Coal-based gasification systems require a particulate removal system, such as hot cyclones, candle filters and syngas scrubbers. Since liquid feedstocks have low ash content, such extensive particulate removal systems are not required.

4. Many coals contain chlorine compounds, which result in the production of high-chloride wastewater streams that require vapor recompression or distillation to remove the chlorides as a brine solid for disposal. Such complex, expensive wastewater treatment systems are not required for low-chlorine liquid feedstocks.

5. All of the liquid feedstock-based IGCC plants in operation are located at refineries, with their primary purpose being the production of hydrogen and/or steam for the adjacent refineries, not to generate electricity. The overall design of coal-based IGCC plants is very different from those designed for liquid feedstocks.

IGCC operational availability is lower when using coal than when using liquid feedstocks. This is proven in actual operational history. None of the five existing coal-based IGCC plants has been able to achieve 80% operational availability on a consistent basis. One has never even achieved 70% operational availability. IGCC plants using liquid feedstocks have a history of higher availability.

The major causes of lower operational availability for coal-based IGCC plants relate directly to the design differences described above. For example, coal-based IGCC plants must contend with additional operational and maintenance issues related to coal delivery, storage and handling systems, coal slurry preparation, process burners, gasifier refractory, slag removal and handling systems, and syngas cleaning and particulate removal systems. Once the coal has been delivered, stored, reclaimed, handled, crushed and slurried, the coal slurry may appear physically similar to some of the liquid gasifier feedstocks. However, there are great differences in chemical composition, ash content, viscosity, erosivity, corrosivity, ash melting temperatures, sulfur content, and many other characteristics which have significant impacts on coal-based IGCC plant design and operational availability. IGCC plants designed for liquid refinery wastes do not have to contend with the erosive and corrosive tendencies of coal slurry and the syngas that is produced from it.

[Correction for Table 1-1 in Mr. Fowler's report: The Nuon IGCC plant uses a blend of coal and wood chips, not just coal.]

Mr. Fowler attempts to make the conclusion that just because there are sixteen IGCC plants, that this "is sufficient to support a conclusion that IGCC has the 'practical potential' for application to coal-fueled power plants in the United States. " It is important to note that of these sixteen plants, seven of them use liquid feedstocks. As described above, the design and performance of liquid feedstock-based IGCC plants cannot be compared to those of coal-based IGCC plants. None of the IGCC plants on the list use Powder River Basin subbituminous coal, and only the coal-based IGCC plants are electric utility plants built to provide electricity for retail customers. All of the others are located at refineries or chemical plants, primarily for supplying steam, hydrogen or chemicals to those adjacent plants. Just because there are sixteen IGCC plants, this in no way implies that IGCC is technically feasible for meeting the site conditions and critical project requirements for Dry Fork Station.

IGCC technology is not commercially available at the 385 MW (net) size needed for the Dry Fork Station. IGCC technology suppliers have demonstrated their technologies at the 250-300 MW (net) scale (although not successfully demonstrated, as history shows). This one gasifier train configuration was only for demonstration purposes, and is not offered commercially. Today, IGCC technology suppliers are only commercially offering an IGCC "reference plant" that uses two 50%-sized gasifiers to produces sufficient syngas to fully load two FB-class gas turbines, with two HRSGs and one steam turbine rated to use the steam from the HRSGs and syngas coolers in the gasification block for additional power generation. This reference plant configuration would generate 770-795 MW (gross) and 600-630 MW (net), using eastern bituminous coal as the feedstock, and operating at or near sea level. The performance and cost impacts when using subbituminous coal, at the high elevation of the Dry Fork Station, would be substantial.

There is no technical basis for Mr. Fowler to conclude that because there are IGCC plants that use liquid feedstocks, that a coal-based IGCC plant, sized at 385 MW (net), and utilizing Powder River Basin subbituminous coal, at high elevation, is a practical choice for the Dry Fork Station site and project requirements.

This is important because it is incorrect and inappropriate to project the performance of IGCC plants that use liquid feedstocks onto the expected performance of coal-based IGCC plants. Operating history shows that the designs and the operation of these plants are completely different.

Page 8. Table 1-2. Dry Fork Station Emission Comparison

Table 1-2 notes that the emission rates are expressed on the basis of "lb/MMBtu coal feed". However, the table contains data with an error frequently made by many that attempt to compare emission rates of different IGCC and PC plants. Emission rates for PC plants are expressed on the basis of pounds of emissions from the stack per MMBtu (lb/MMBtu) of coal heat input to the boiler. Emission rates for natural gas-fired gas turbines are expressed on the basis of pounds of emissions leaving the gas turbine or HRSG stack per MMBtu of natural gas entering the gas turbine. In the case of IGCC plant permits and permit applications, the emission rate basis that is used varies from plant to plant. Some express the emission rates on the basis of coal heat input to the gasifier, in order to be able to compare the IGCC plant to PC plants. Others express emission rates on the basis of syngas heat input to the gas turbines, in order to compare the IGCC units to natural gas-fired combined cycle units.

This is important because it is inappropriate to use different emission rate units to compare emission rates of different IGCC and PC power plants; doing so provides a false comparison. One must fully understand the differences and use the correct emission rates consistently.

It is important to understand the basis of published emission rates, and it is appropriate to compare emission rates only if they are on the same basis. That is because the heat input of the syngas to the gas turbine is typically only 70-80% of the coal heat input to the gasifier. The difference is due to chemical and thermal losses in the gasification process. The impact of this difference is that the emission rate expressed on a gas turbine basis is higher than that expressed on a coal heat input basis, for the same pounds of emissions leaving the power block stack. Those with experience in the permitting and design of IGCC plants understand this difference and note the basis of emission rates when referencing them.

Fowler notes that the values in his Table 1-1 are on a coal input basis. However, several of the values appear to be on a CT input basis, based on a review of the permits and permit applications that he has referenced. It is not clear why Mr. Fowler stated that the values in the table are on a coal input basis, but apparently used values both on a coal input basis and a CT input basis in the table. As noted above, it is not appropriate to make comparisons of emission rates on the different bases. The table below lists the apparent heat input basis for each of the emission rates. Values provided on the basis of syngas input to the gas turbine (combustion turbine) are noted as "CT input".

Plant	Emission Rate Basis (used by Mr. Fowler)
Dry Fork PC	Coal input
Taylorville IGCC	SO_2: CT input
	NOx, PM, CO, VOC: coal input
Edwardsport IGCC	PM, CO, VOC: coal input
	SO_2, NOx: CT input
Mountaineer IGCC	SO_2: unknown - this value falls between the coal input value (0.017) and the CT input value (0.024)
	NOx, PM, CO, VOC: coal input
Mesaba IGCC (application)	Coal input
Mesaba IGCC (agency)	Coal input
Polk IGCC	Coal input
EPA IGCC*	Coal input

* The EPA study values are based on the use of a GE Energy gasification system with subbituminous coal. The values listed for the EPA report are inappropriate to use since GE Energy does not commercially offer an IGCC technology for use with subbituminous coal.

This is important because a comparison of emission rates from different generating units must use the same emission rate basis.

Mr. Fowler attempts to make a case that the hypothetical IGCC plant should use the emission rates in the air permit application for the Mesaba IGCC project, but with some key modifications. He notes that these modifications are based a letter from the Minnesota Pollution Control Agency[11] to the Minnesota Department of Commerce, requesting that the Final Environmental Impact Statement (FEIS) for the Mesaba project should reflect the use of Selexol for sulfur removal and selective catalytic reduction (SCR) for NOx removal. The agency stated that "Selexol is a cost-effective technology for syngas sulfur removal to a level of 20 parts per million by volume (ppmv) or less, resulting in lower sulfur dioxide emissions and meets the required application of Best Available Control Technology (BACT) required by the Clean Air Act". Interestingly, the agency made its statement regarding Selexol without providing either an analysis of the technical feasibility or the cost effectiveness calculations for that specific project (BACT is supposed to be project-specific).

For SCR, the agency noted that "SCR is technically feasible", but it did not even mention the impacts of ammonium-sulfur salts that are widely known in the industry as rendering SCR technically infeasible for IGCC. The agency then noted "This may be required to fulfill BACT requirements based on the required cost analysis..". The agency did not state that the Mesaba IGCC project is required to use such technologies, only that they should be reflected in the FEIS.

While I did not agree with Mr. Fowler's assumptions regarding the use of Selexol for sulfur removal, the cost-effectiveness calculations now reflect the use of Selexol (although it is shown not to be cost-effective). SCR is still considered to be technically infeasible for application to IGCC technology, and it is not included as part of the design of the hypothetical IGCC plant. The SCR technical infeasibility issues are addressed later in this report.

Page 8. Step 2 – Eliminate Technically Infeasible Options

Mr. Fowler notes EPA's guidance that "for control options that are demonstrated, the option is assumed to be technically feasible; for control options that are not demonstrated the option is assumed to be technically feasible if it is commercially available and can reasonably be installed and operated on the source."

While there are five IGCC demonstration plants, the operating histories show that the IGCC technologies used have not been successfully demonstrated, as none has met its design targets for availability or other performance indicators. Therefore, there is not a basis to consider IGCC as being successfully demonstrated. Based on the EPA definition, IGCC would only be technically feasible if it has "been installed and operated successfully on the type of source under review". IGCC has never been installed and operated successfully on an IGCC plant designed to use subbituminous coal at high elevation, and providing 95% availability.

As noted above, IGCC is <u>not commercially available</u> at the 385 MW (net) size required for the Dry Fork Station. It cannot be reasonably installed and operated if it is not commercially available. Therefore, IGCC technology is technically infeasible for the Dry Fork Station and is eliminated from Step 2 of the BACT top-down methodology.

This is important because saying that a technology is technically feasible does not make it so, especially when the operating history has proved otherwise. IGCC is not technically feasible for the Dry Fork Station project.

Page 9. IGCC Demonstrations and Operating Experience

Mr. Fowler states that "IGCC is a demonstrated technology because it has been installed and operated successfully." The operating histories of the IGCC demonstration plants certainly prove otherwise. To attempt to show that IGCC has high availability, Mr. Fowler misuses availability information from the IGCC demonstration plants. The availability of the entire IGCC plant, not just portions of it, must be considered when comparing IGCC availability to the high availability achieved by PC plants.

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[11] "Minnesota Pollution Control Agency Comments on the Draft Environmental Impact Statement for the Mesaba Energy Project", filed with the Minnesota Department of Commerce, January 11, 2008.

For Polk Power Station, Mr. Fowler cites the availability of the power block as being in excess of 88% in specific years. When the gasification area is down for maintenance or other problems, the power block at Polk Power Station can be operated using high-cost diesel. However, this is not IGCC operation; it is power block only operation. Tampa Electric Company built a full IGCC plant that it intended to operate; it did not intend to pay for a complete gasification plant that it would not use. The availability of the complete IGCC plant is what must be considered and compared.

Mr. Fowler's Exhibit III presents data developed by Tampa Electric Company. This graph clearly shows that the availability of their IGCC plant has never been greater than 81%. The actual IGCC plant design value was for 85% availability[12] when using syngas, to be achieved by the second year of operation. After more than 11 years of operation, the plant has yet to come close to its design value. The difference between 81% and 85% is significant, as it represents the need for other units (or just the plant's power block on high-cost diesel) to provide the generation that the IGCC plant is unable to provide. For the Dry Fork Station, the design availability is 95%. An availability of 85% would not meet the requirements of the Dry Fork Station and BEPC's customers, and 81% availability would be unacceptable.

Mr. Fowler's report notes that the availability of syngas at the Wabash River IGCC plant never fell "below approximately 70%." Such a value is far below the design availability of the Wabash River IGCC plant, and even farther below the availability required for Dry Fork Station. An availability of 70% would be unacceptable for Dry Fork Station.

Mr. Fowler's report cites data from the ISAB plant in Italy, which uses liquid refinery wastes as a feedstock. As noted above, it is inappropriate to compare designs and operation of IGCC plants that use liquid refinery wastes to coal-based IGCC plants.

For the Nuon plant in the Netherlands, Mr. Fowler's Exhibit VI shows that the IGCC plant finally achieved an availability level of 80% in 2006, after 12 years of operation. This low availability would not be acceptable for the requirements for Dry Fork Station and BEPC's

[12] "Final Public Design Report", July 1996, Tampa Electric Company.

customers. Further, it is important to note that the PC technology selected by BEPC is proven worldwide, typically achieving high availability in the first 1-2 years after startup. As Mr. Fowler's Exhibit V clearly shows, the Nuon IGCC plant did not even achieve 30% availability during its first 3 years of operation. Such performance would not be acceptable for the requirements for Dry Fork Station and BEPC's customers.

Even by incorporating thousands of lessons learned from Polk Power Station Unit 1, Tampa Electric Company noted (and Mr. Fowler cites) in its submittals to the Florida Public Service Commission for its proposed Polk Power Station Unit 6 IGCC plant, that the new plant would only achieve 86% availability. This, too, would not be acceptable for requirements for Dry Fork Station and BEPC's customers.

These points are important, because comparisons of availability must include the entire IGCC plant, not just portions of it. Looking only at portions of the IGCC plant does not hide the fact that the overall IGCC plant's availability is low and would not meet the 95% availability requirements of Dry Fork Station

Page 10. Commercial Availability of ConocoPhillips IGCC Technology

While ConocoPhillips does commercially offer its E-Gas™ technology, its standard design is for approximately 600-630 MW (net)[13]. ConocoPhillips <u>does not</u> commercially offer an IGCC plant for the 385 MW (net) size needed for the Dry Fork Station and BEPC's customers. This point is validated by Mr. Fowler's reference to the proposed Mesaba IGCC project in Minnesota, which plans to use ConocoPhillips IGCC technology. The Mesaba IGCC plant will be designed for 606 MW (net). Contrary to statements in Mr. Fowler's report, the Mesaba IGCC plant <u>would</u> be a novel design, in that no other IGCC plants have been, or are being, designed to use a combination of "Powder River Basin sub-bituminous coal blended with Illinois bituminous coal and up to 50% petroleum coke."

It is very important to understand that just because IGCC technology is planned for the Mesaba IGCC project at 606 MW (net), this does not in any way imply that it is commercially available for the 385 MW (net) size needed for Dry Fork Station.

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[13] "Comparative IGCC Performance and Costs for Domestic Coals", Dr. David L. Breton and Clifton G. Keeler, ConocoPhillips, October, 2005.

Page 11. Commercial Availability of GE IGCC Technology

While the GE/Bechtel alliance was created to commercially offer the GE IGCC technology on a turnkey basis, with guarantees and warranties, none have been sold on this basis to date. Therefore, the nature of the guarantees and warranties that might be offered is unknown.

More importantly, it is not clear why Mr. Fowler included GE Energy technology in this report. GE's IGCC technology is only offered commercially for use with eastern bituminous coal in the reference plant configuration with a net output of approximately 630 MW[14]. GE has no commercially available IGCC technology that can be used with subbituminous coal. The portion of Mr. Fowler's report that discusses the applicability of GE IGCC technology to the Dry Fork Station is moot. In response to BEPC's request for proposals for the IGCC study, GE was very clear in noting that they did not commercially offer what BEPC required for Dry Fork Station.

An expert on IGCC technology would not have even considered including GE Energy technology as a possible supplier of technology for use with subbituminous coal, because GE Energy does not even commercially offer such a technology.

Page 12. Commercial Availability of Shell IGCC Technology

As Mr. Fowler points out, Shell did enter into an alliance in 2004 with Uhde and Black & Veatch to "facilitate commercial offerings for engineering, procurement and construction (EPC) of gasification and integrated gasification combined cycle (IGCC) projects that have selected the Shell coal gasification technology for solid fuels such as coal and petroleum coke." To date, this alliance has not completed any such EPC contracts for IGCC plants. Just because such commercial arrangements are available does not infer that they are commercially reasonable or provide the types of guarantees on cost, schedule and performance that are generally available with PC technology. More importantly, this Shell-Uhde-Black & Veatch alliance is no longer in existence for IGCC plants.

While Mr. Fowler referenced Nuon's proposed 1,200 MW IGCC plant, he failed to note that the gasification portion of this proposed plant has been delayed for several years to further

[14] "GE's Gasification Business", John Lavelle, General Manager, Gasification, GE Energy, October 2007.

study recent significant cost increases, and the plant is going forward as a natural gas-fired combined cycle power plant[15]. On May 9, 2008, Nuon announced that construction of the plant had been stopped due to permitting reasons.

This is important because Shell is one of the top three IGCC technology suppliers. An IGCC expert would be well versed on the Shell technology and its use in proposed IGCC plants.

Page 13. Applicability of IGCC Technology to the Dry Fork Site

Contrary to Mr. Fowler's statement, IGCC is not applicable to a 385 MW (net) plant designed to utilize subbituminous coal from the Powder River Basin at an elevation of 4,560 feet. As noted above, IGCC technology is not even commercially available at this size. Therefore, it cannot "reasonably be installed and operated on the source type under consideration."

Further, the source type selected for the Dry Fork Station is PC technology. IGCC is a separate and distinct power generation technology from PC, not an emission control technology that can be installed on, retrofitted on, or designed into a PC plant. IGCC fails to meet the NSR Manual definition of "applicable", and is therefore not an available technology for use at the Dry Fork Station.

Mr. Fowler makes the statement "Among the 'available' IGCC technologies noted above the ConocoPhillips offering is the most obviously applicable to the Dry Fork site." However, none of the information that he provides supports the conclusion that this technology is commercially available for meeting the requirements for a plant sized at 385 MW (net), using Powder River Basin subbituminous coal, operating at 4,560 feet elevation, and providing 95% availability.

This is important because an IGCC expert would not make such a general conclusion without considering whether the specific technology could meet the project-specific requirements.

Mr. Fowler notes "There are two distinctive elements of the Dry Fork plant proposal that could impact applicability of IGCC there. They are elevation and coal type. Neither of these

[15] http://www.nuon.com/press/press-releases/20070918/index.jsp

differences represents a technical impediment to successful operation of an IGCC at Dry Fork." It is obvious from Mr. Fowler's resume and this statement that he has no technical experience with either the design or the operation of IGCC plants, with any coal or at any altitude. Stating that the impacts of elevation do not represent a technical impediment to successful operation of IGCC shows a lack of understanding of IGCC technology and its performance.

At the higher elevation, as Mr. Fowler states, "the combustion turbine portion of an IGCC plant cannot move a sufficient mass of air through its combustors to generate the same amount of output it does at sea level." What this means is that the amount of syngas that can be combusted is reduced, since less air is available. Therefore, the design coal throughput must be reduced along with that, since less syngas is required. Along with that, the amount of oxygen required to gasify the coal is reduced. The capacity of the air separation unit would therefore be reduced. Mr. Fowler notes that "the air separation unit of an IGCC (used to supply oxygen to the gasifier) must be slightly larger for units operating at high elevation." This is incorrect. As noted above, the oxygen production requirement from the air separation unit would be reduced, and the unit would be smaller, not larger.

In a recent detailed study conducted by ConocoPhillips and WorleyParsons[16], the impacts of elevation were determined for a plant at sea level and one at over 4,000 feet altitude. The study was based on the ConocoPhillips commercial offering, as described above. The column "Impact of high elevation" in the table below provides the results of the study. The base values for the IGCC plant at sea level are from a prior study performed by ConocoPhillips in 2006[17]. The approximate values at the 4,000 foot level are calculated from the per cent reduction values.

16 "CO_2 Capture: Impacts on IGCC Plant Performance in a High Elevation Application using Western Sub-bituminous Coal", Satish Gadde and Jay White (WorleyParsons) and Ron Herbanek and Jayesh Shah (ConocoPhillips), October, 2007.

17 "E-Gas Applications for Sub-Bituminous Coal", Ron Herbanek and Thomas A. Lynch, ConocoPhillips, October, 2005.

Gross plant output, MW	IGCC plant at sea level	Impact of high elevation	IGCC at 4,000'
Gas turbine	464	-9%	422
Steam turbine	314	-16%	263
Total gross output, MW	778	-12%	685
Total aux loads and losses, MW	134	-8%	123
Net power output, MW	644	-13%	561

A reduction of 13% of net power output, or 83 MW, would be a significant performance impact on an IGCC plant due to the elevation of the Dry Fork Station site. Since the Dry Fork Station site is even higher than 4,000 feet, the impacts at that site would be even more pronounced. This significant impact is not to be taken lightly. Contrary to the statements in Mr. Fowler's report, the impacts of elevation are a technical impediment to successful operation of an IGCC plant at the Dry Fork Station site.

This is an important point, since the impacts of elevation are significant, and should not be taken lightly. To state that the significant impacts of elevation on IGCC technology are not a technical impediment shows a lack of understanding of the basic engineering principles of IGCC plant design and operation.

Page 14. Applicability of IGCC Technology to the Dry Fork Site

Mr. Fowler notes here that "regulators in at least one state have determined that IGCC is technically feasible based on EPA's criteria." He refers to the state of New Mexico, where the agency found that "a 300 MW IGCC plant using high ash sub-bituminous coal at 7000 feet elevation was found to be technically feasible by the permitting agency."

Here, Mr. Fowler cites his own work, performed while an employee of that New Mexico agency, in order to support his conclusions regarding the Dry Fork Station (see Exhibit II of Mr. Fowler's report). It is not clear how he reached his conclusions that IGCC is technically feasible for a 300 MW plant at 7,000 feet elevation in New Mexico. However, using IGCC technology in a plant that is even smaller and at a higher elevation than the Dry Fork Station would likely be less technically feasible than for the Dry Fork Station, based on the same issues of smaller size, commercial availability, higher cost, and availability. Further, the historical data for IGCC demonstration plants, as described above, clearly shows that IGCC has not been able to generate electricity in the 300 MW (gross) range with high reliability. His statement that "IGCC can reliably generate 300 megawatts at the Mustang site" contradicts the historical data.

Just because Mr. Fowler made certain conclusions regarding the applicability of IGCC at another site located in another state (and citing his own prior work), this in no way supports the contention that such technology would be technically feasible for the Dry Fork Station.

Regardless of how Mr. Fowler reached these conclusions, when one correctly uses the criteria in the NSR Manual, the conclusion is that IGCC is not technically feasible for BEPC's project, based on the requirement for a 385 MW (net) plant that can provide 95% availability, using subbituminous coal at the 4,560 foot elevation of the Dry Fork Station.

Page 14. Applicability of IGCC Technology to the Dry Fork Site

Mr. Fowler quotes the following excerpt from the 2005 technology evaluation report:

> "The IGCC option is probably technically feasible for use in reducing SO_2, NOx, PM, CO and VOC emissions from the new unit".

However, he only uses part of the sentence from the report, leaving out the rest of the sentence, which is the critical qualifying statement:

> "but it is not considered the best application for PRB coal."

As the 2007 report and this report clearly state, IGCC is not technically feasible for BEPC's project, and only PC technology can meet the requirements for generating 385 MW (net), with 95% availability, using subbituminous coal, and at the 4,560-foot elevation of the Dry Fork Station.

Taking specific statements out of context and quoting them still does not change the basic fact that IGCC technology is not applicable to the Dry Fork Station site.

Page 14. Table 3-1 Summary of Emissions and Cost Data for Dry Fork BACT

Prior capital cost estimates for IGCC technology must be escalated due to the significant escalation in materials and labor described above. The most accurate cost information for an IGCC plant designed for eastern bituminous coal is Duke Energy Indiana's 795 MW gross/630 MW net Edwardsport IGCC project. As previously noted, its revised cost estimate is $2.35 billion, or $3,730/kW (based on using eastern bituminous coal). An IGCC plant designed for subbituminous coal would cost 14% more than one designed for eastern bituminous coal[18], or $2.683 billion ($4,259/kW).

Adjustments need to be made to this cost based on the impacts of elevation and size. As described previously, the plant net output would be reduced by 13% to account for all of the elevation impacts. While some components of the gasification island would be smaller, since less coal would be gasified, some portions of the IGCC plant would remain the same size. The gas turbines are commercially available at a standard size, and would have to operate below their maximum rated output due to the less dense air. The steam turbine, which would be about 16% smaller (as shown in the table above), could be manufactured at a size closer to that lower capacity. Overall, the IGCC plant cost could be reduced by about 8%. Therefore, the hypothetical IGCC plant at elevation would cost $2.47 billion, with a net output of only 561 MW. This increases the capital cost value to $4,403/kW.

Industrial facilities, including power plants, benefit from economy of scale. For cost estimating purposes, the following formula (known as the "six tenths factor") is commonly used in the power and chemical process industries to determine the cost of a different size of plant based on the cost of a plant with known cost information.

Cost of larger plant x (smaller plant MW/larger plant MW)$^{0.6}$ = cost of smaller plant

On this basis, the 385 MW (net) size hypothetical IGCC plant would cost $1.97 billion, or $5,117/kW. Additional adjustments are described below.

18 "Cost and Performance of Current IGCC Offering", Phil Amick, ConocoPhillips, June, 2004.

Even for this hypothetical BACT analysis, it is important to develop an accurate cost estimate for IGCC technology. The impacts of plant size and the significant increases in cost must be taken into account.

Page 15. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Use of Selective Catalytic Reduction (SCR) system for Additional NOx Reduction
Mr. Fowler makes the assumptions that SCR is applicable to the hypothetical IGCC plant for additional NOx reduction. This is not a valid assumption. SCR is not technically feasible for IGCC technology due to concerns regarding operational impacts to downstream equipment. This is caused by the reaction of the sulfur compounds in the syngas with the ammonia injected into the SCR system, resulting in the formation of ammonium sulfate and ammonium bisulfate salts. These are sticky, corrosive deposits that would require excessive IGCC plant shutdowns for washing the HRSG to remove these harmful deposits.

The uncertainty regarding the technical feasibility of SCR for IGCC plants continues. In the "Footprints Report", the EPA addressed the application of SCR with IGCC technology. The report acknowledges the differences in applying SCR to IGCC by stating:

> "….there are fundamental differences between natural gas and syngas-fired turbines that make the use of SCR with IGCC technologies more uncertain, and there are no installations at present at IGCC facilities firing coal."

EPA's report identifies concerns regarding the impacts of ammonium sulfate and ammonium bisulfate compounds on the performance and maintenance requirements of downstream equipment. The impact to the HRSG performance is noted to be a crucial concern when applying an SCR system to an IGCC plant. Without an extensive R&D project to identify design characteristics required to alleviate feasibility concerns, it is difficult to evaluate the cost effectiveness of applying an SCR to IGCC. None of the planned IGCC plants (with or without SCR) will be in service until 2012 or later. While SCR technology is commercially available for PC and gas-fired combined cycle plants, it cannot be considered commercially available yet for application to coal-based IGCC at full-scale operations.

On that basis, SCR is not technically feasible at this time for application to IGCC technology.

This is a very important point, because it would be incorrect to assume that just because SCR works on a natural gas-fired plant that it will work on an IGCC plant. It will be five to seven years before we know whether SCR works on the full-scale IGCC plants. It is just too soon to make a technical conclusion.

Application of Selexol for Additional Sulfur Removal

Mr. Fowler's cost effectiveness calculations are based on the assumption that that the IGCC-proven MDEA acid gas removal system should be replaced with Selexol, in order to achieve additional reductions in SO_2 emissions. His report notes:

> "For the IGCC plant the base capital cost, adopted directly from the Basin Report, is adjusted upward by a line-item addition for installation of Selexol and SCR (annualized at $1.8 million per year over the life of the project) based on data provided in a 2006 EPA report titled *Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies* ("Footprints Report"). Costs derived from the Footprints Report have been escalated to include a +33% increase in cost levels since the period of the report (4th Quarter 2004)."

As noted above, SCR is not yet technically feasible for application to IGCC technology, so any cost addition for SCR is not appropriate. Further, history now shows that the capital cost information in the "Footprints Report" was inaccurate (very low), and the cost escalation factors have proven to be significantly low.

In order to analyze the impacts of changing to Selexol, the capital and O&M costs for a Selexol system must be determined for the hypothetical IGCC plant. A good source of detailed information on these costs is the BACT analysis portion of the air permit application for AEPs proposed Great Bend IGCC Plant[19]. Using the information in that BACT analysis, the MDEA sulfur block that would achieve 50 ppmv sulfur in the undiluted

[19] "Application to the Ohio Environmental Protection Agency for a Permit to Install Pursuant to Chapter 3745-31 of the Ohio Administrative Code, AEP Ohio Great Bend Facility", American Electric Power, September, 2006.

syngas (0.025 lb/MMBtu emission rate equivalent) would have a capital cost of $115 million. The capital cost for a Selexol-based sulfur block to meet the 20 ppmv sulfur level (0.01 lb/MMBtu emission rate equivalent) is shown as $178.4 million.

These capital costs are in 2006 dollars, so that escalation to today would increase them by 59% (per the CERA Power Capital Costs Index) as follows:

-Selexol (2008): $283.7 million

-MDEA (2008): $182.9 million

Since these costs are for a 784 MW (gross) IGCC plant, they must be adjusted to determine the capital costs for the smaller, hypothetical IGCC plant for this analysis.

Using the economy of scale conversion, the plant costs for a 422 MW (gross) IGCC plant would be (*Cost of larger plant x (smaller plant MW/larger plant MW)$^{0.6}$ = cost of smaller plant)*:

-Selexol: $195.6 million

-MDEA: $126.1 million

Therefore, the additional capital cost to change to the Selexol system would be $69.5 million. The adjusted total installed capital cost for the hypothetical IGCC plant is $2 billion, or $5,406/kW.

Using the cost data in the AEP Great Bend air permit application, the annual O&M costs (2006) for the MDEA and Selexol options are:

-Selexol: $11 million

-MDEA: $8.6 million

Escalated to 2008, these annual O&M costs become:

-Selexol: $11.44 million

-MDEA: $8.9 million

Reducing the O&M costs for the smaller size of the hypothetical IGCC plant at Dry Fork Station unit would result in annual O&M costs of:

-Selexol: $6.2 million

-MDEA: $4.8 million

Therefore, the additional annual O&M cost is $1.4 million.

Although I did not agree with Mr. Fowler's conclusion that Selexol was cost-effective, it was informative to analyze the impacts of including it on the hypothetical IGCC plant. When the correct *cost and performance values are used, we find that <u>Selexol actually would not be cost effective</u>. The MDEA-based acid gas removal system that was selected for the hypothetical IGCC plant (as well as for the Mesaba IGCC plant that Mr. Fowler cites) would still be the most cost-effective emission control for use in this hypothetical BACT analysis.*

Page 16. Table 3-1 Summary of Emissions and Cost Data for Dry Fork BACT

The SO_2 emission rate with MDEA is 0.025 lb/MMBtu (on a coal input basis). With Selexol, the emission rate would be 0.01lb/MMBtu, and the SO_2 emissions would be reduced by an additional 115 tons/year.

For determining the annual O&M values, Mr. Fowler notes that he used the values "adopted directly from the Basin Report", and then adjusted them to make them consistent with the EPA "Footprints Report", which notes that O&M for PC plants should be about 95% of that for IGCC plants. This assumption from the "Footprints Report" is also inaccurate. Based on more recent and accurate industry data, as well as the data in the DOE report referenced in the following paragraph, O&M costs for PC plants are 60-80% of that for IGCC plants, not 95%. This confirms what the industry has learned from the operation of the four longer-operating IGCC demonstration plants, in that IGCC <u>plants are much more costly to operate and maintain than PC plants.</u>

More accurate annual O&M costs for the hypothetical IGCC plant are taken from the DOE's report "Cost and Performance Baseline for Fossil Energy Plants". In that report, DOE provides an annual O&M cost estimate of $49.7 million for a 742.5 MW (gross), 623 MW (net) IGCC plant based on ConocoPhillips technology using eastern bituminous coal. That value is then adjusted to be more representative of the smaller size of the hypothetical IGCC plant.

An updated version of Mr. Fowler's Table 3-1 is presented below. IGCC emission rates are based on Mr. Fowler's modified "Mesaba IGCC" values, except for NOx (no SCR).

Attribute	PC	IGCC
SO_2 emissions, lb/MMBtu coal feed	0.070	0.01
NOx emissions, lb/MMBtu coal feed	0.050	0.057
PM (filterable) emissions, lb/MMBtu coal feed	0.012	0.009
CO emissions, lb/MMBtu coal feed	0.150	0.035
VOC emissions, lb/MMBtu coal feed	0.004	0.003
Plant capital cost, $/kW	$3,668	$5,406
Plant O&M cost, $1,000/yr	$17,450	$29,600
Plant heat rate, Btu/kWh (HHV)	10,077	9,500

When making the calculations for selecting emission control technologies via the BACT analysis, it is very important to use the most up-to-date capital and O&M costs. Doing otherwise results in the wrong answer, especially in the environment of significant cost increases that the industry is experiencing.

Page 17. Table 4-1 Incremental Cost Effectiveness of IGCC at Dry Fork

Using the updated values described above, a corrected version of Table 4-1 in Mr. Fowler's report, using more accurate and representative data, is provided below.

Attribute	PC	IGCC	Delta
Annualized Capital Cost, M$/yr	$88.70	$130.7	$42.00
Annual Non-Fuel Cost, M$/yr	$17.45	$29.60	$12.15
Annual Fuel Cost, M$/yr	$14.50	$28.6	$14.11
Total Annual Cost, M$/yr	$121	$189.51	$68.51
Total Annual Emissions (tons/yr)	4,182	1,587	(2,595)
Total Incremental Cost Effectiveness ($/ton)	-	-	**$26,400**

The overall incremental cost effectiveness of IGCC, at $26,400/ton, is not a reasonable value and is far above the cost effectiveness level of $9,962/ton for SO_2 that Mr. Fowler notes has been approved by the Wyoming DEQ for use of a spray dryer absorber at Dry Fork Station. Based on the updated information provided in the DOE report referenced above, IGCC technology is eliminated from further consideration in the BACT analysis, and PC remains the only power generation technology for Dry Fork Station.

For the purposes of this hypothetical BACT analysis, this may be the most important point. Taking IGCC technology through the BACT analysis clearly shows that it is not cost effective. PC technology is still the only power generation technology choice for Dry Fork Station.

CONCLUSION

This assessment of IGCC technology confirms the conclusions that CH2M HILL reached in the prior technology assessment reports regarding its potential use at Dry Fork Station.

1. IGCC and PC are two very different power generation technologies, incorporating very different processes. Substituting IGCC technology for PC technology at Dry Fork Station would be completely redefining the source of power generation technology.

2. IGCC technology is neither commercially available nor technically feasible for meeting the project requirements for Dry Fork Station, as those terms are defined in the NSR Manual. IGCC technology suppliers do not commercially offer a 385 MW (net) IGCC power plant for use with Powder River Basin subbituminous coal, operating at an elevation of 4,560 feet, and with the ability to provide 95% availability.

3. Even if BEPC were able to purchase IGCC technology for use at Dry Fork Station, it still would not be BACT. The BACT analysis clearly shows that PC technology is BACT for the Dry Fork Station project.

1

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Thirty-two years in the power industry, with significant experience in permitting, design, and operation of large integrated coal gasification combined cycle and coal-fired generating units, and managing large, complex engineering and environmental power plant projects utilizing coal, petroleum coke, coal/coal waste, municipal solid waste, oil, and natural gas in conventional (pulverized coal and cyclone boilers) and advanced power generation technologies (integrated gasification combined cycle, gasification, pyrolysis, and plasma gasification).

<u>IGCC and Gasification Facilities</u>

- Project Manager, IGCC Technical Issues and DOE Liaison for permitting and licensing of Excelsior Energy's 1,200 MW Mesaba Energy IGCC Project, to be located in northeastern Minnesota. The Project is receiving co-funding from DOE's Clean Coal Power Initiative and will use ConocoPhillips E-Gas gasification technology. Feedstocks will include Powder River Basin and Illinois #6 coals, along with blends with pet coke.
- Lead author of the industry's first IGCC Permitting Guidelines Manual, prepared for the Electric Power Research Institute's CoalFleet for Tomorrow Program.
- IGCC Technical Lead for technical feasibility and environmental permitting strategy for addition of a pet coke gasification plant to an existing NGCC plant in eastern Pennsylvania.
- IGCC expert for development of EPRI's IGCC User Design Basis Specification
- IGCC Technical Lead for feasibility study and environmental permitting strategies for re-fueling an existing NGCC plant in central Louisiana to syngas from a new petroleum coke/coal gasification facility. Work included material balances, preliminary site layouts, cost estimates, and engineering and construction schedules.
- IGCC Technical Lead for development of permitting plans and strategies for addition of a pet coke gasification plant to an existing fertilizer plant in central Louisiana.
- Gasification Technical Lead for environmental permitting feasibility study of the addition of a new petroleum coke

TECO Power Services Corp., Deputy Project Manager, Polk Power Station, 1992-1996

Tampa Electric Company, Various positions in power plant engineering, operations, construction, fuels, coal combustion by-products management, and environmental/regulatory affairs, 1975-1992

PUBLICATIONS

Technical Editor and Co-author: "Opportunities to Expedite the Construction of New Coal-Based Power Plants", The National Coal Council, November 2004.

Technical Editor and Co-author: Coal-Related Greenhouse Gas Management Issues", The National Coal Council, May 2003.

Technical Editor and Co-author: "Increasing Coal-Fired Generation through 2010: Challenges and Opportunities", The National Coal Council, May 2002.

Technical Editor and Co-author: "Increasing Availability of Coal-Fired Generation in the Near Term", The National Coal Council, May 2001.

gasification facility at an existing industrial site along the Houston ship channel, for production of hydrogen for an adjacent refinery and CO for an acetic acid plant.

- Technical Lead for a detailed gasification and IGCC technology feasibility study for a large coal company. Tasks included evaluation of technologies and the technical and economic feasibility for production of power, chemicals, and Fischer-Tropsch fuels from eastern and western coal reserves.
- Technical Lead for IGCC technology portion of air permitting for AEP's Great Bend and Mountaineer IGCC projects.
- Technical Lead for air permitting for Global Energy's Kentucky Pioneer IGCC and Lima Energy IGCC Projects.
- Project Manager for development of permitting strategies and a Supplemental EIS for Texaco Power & Gasification's 1,500 MW IGCC power plant to be sited adjacent to TVA's Bellefonte Nuclear Plant in Scottsboro, Alabama.
- Deputy Project Manager for the permitting, engineering, design, equipment fabrication, delivery and construction of Tampa Electric Company's 250 MW Polk Power Station, an integrated coal gasification combined cycle power plant, constructed in partnership with the U.S. DOE.

MSW Conversion Technologies

- Technical Lead for evaluation of pyrolysis, gasification and plasma gasification technologies for the Region of Halton, Ontario, Canada. The evaluation included throughput, feedstock characteristics, by-products, power production, emissions, environmental issues, and feedstock flexibility for these technologies to be used in a 125,000 ton/year Energy from Waste Facility.
- Technical Lead for evaluation of pyrolysis and gasification technologies for converting 150 tons/day of ponderosa pine sawdust to power for a power plant development company in California.
- Technical Lead for evaluation of >200 gasification, pyrolysis and power generation technologies and suppliers for proposed facilities to treat up to 4,000 tons/day of MSW for the City of Los Angeles. Prepared the industry's

Industry Associations

Member, Gasification Technologies Council

Member, Electric Power Research Institute IGCC Experts Panel

most comprehensive MSW conversion technology database, along with a publicly-available report. Also prepared a detailed RFP for the City to use in acquiring a 1,200 ton/day facility.

- Technical Lead for evaluation of >100 gasification, plasma gasification, pyrolysis, thermal depolymerization, and power generation technologies and suppliers for a proposed facility to treat up to 250 tons/day of processed MSW for Los Angeles County.
- Technical Lead for evaluation of >100 gasification, plasma gasification, and pyrolysis technologies and suppliers for a proposed facility to treat 200,000 tons/year of MSW for Alameda Power & Telecom.
- Project Manager for the technical, regulatory and economic evaluation of a pyrolysis/gasification facility proposed to treat 200,000 tons/year for the U.S. Virgin Islands.

Coal- and Gas-Fired Power Plants

- Project Manager for siting, site evaluation, permitting, design and construction management of a new coal combustion by-products landfill for Lakeland Electric, on a 250-acre site in central Florida.
- Project Manager for site assessments, preliminary site engineering, and permitting for Calpine's proposed 680 MW natural gas-fired simple cycle power plant in Polk County, Florida.
- Project Manager for due diligence for the successful acquisition of TECO Power Services' Hardee Power Station by Invenergy, LLC. Led a team of air, water, and waste engineers through site evaluations and permit documentation reviews, determining potential environmental liabilities and compliance costs.
- Project Manager for conceptual engineering, site configuration, permitting, and land use/zoning for El Paso Merchant Energy's three proposed natural gas-fired combined cycle units (750-1,000 MW) in Florida.
- Project Manager for site assessments and development of photosimulations for Reliant Energy Whole Group's

proposed 530 MW gas-fired combined cycle power plant in Central Florida. Managed development of 3-D models and photosimulations of the proposed plant. Met with agency staff and the public to explain the plant and its operation.

- Project Principal for FPL Energy's 1,000 MW gas-fired combined cycle power plant in Louisiana and 620 MW gas-fired simple cycle power plant in Kentucky.
- Project Manager for conceptual engineering, site configuration, permitting, and land use/zoning for three natural gas-fired combined cycle units (750-1,000 MW) for El Paso Merchant Energy in Florida.
- Managed environmental permitting, fuel, and combustion by-product portions of two acquisition projects utilizing fluid bed combustion of coal wastes (Utah and Pennsylvania).

Environmental Strategies and Permitting

- Developed strategy to maximize environmental, financial, and tax benefits for over $80 million of SO_2 allowances as part of a $600 million power plant repowering.
- Served as co-author and technical editor for key reports prepared for the Secretary of Energy by the National Coal Council, highlighting the performance, environmental attributes, regulatory requirements and implementation incentives for advanced coal-based technologies.
- Directed federal energy and environmental affairs for TECO Energy, Inc.
- Chaired/co-chaired U.S. industry associations and coalitions in formulating national air quality and global climate change policies and draft legislation.
- Served on Edison Electric Institute's Executive Loan Program, assisting in development of legislation of the Clean Air Act Amendments of 1990 and Energy Policy Act of 1992.
- Presented environmental programs to community groups, environmental groups, and governmental/congressional representatives, highlighting design concepts, environmental performance, and cost benefits for electric utility projects requiring permits and public input.

- Obtained permits for power plant air, water, and solid wastes from local, state, and federal agencies.

Coal-Fired Power Plant Operations

- Managed environmental and chemical engineering group responsible for performance testing, air emission control system enhancements, combustion improvements, and water treatment for 2,800 MW of coal-fired units.
- Chemical engineer and environmental coordinator in a 1,200 MW coal-fired power plant, responsible for combustion and performance optimization, fuel and combustion additives, air emission controls, boiler chemistry, chemical cleaning, water purification, and wastewater treatment.
- Marketed and sold all combustion by-products, including fly ash, bottom ash, slag and gypsum from all coal-fired units operated by Tampa Electric Company.

Emission Control Technologies

- Lead engineer for the Big Bend Unit 4 FGD system, the first FGD system in the U.S. designed to produce commercial grade gypsum.
- Installed and operated flue gas conditioning systems to enhance electrostatic precipitator operation with low sulfur coals.
- Site project engineer for construction and operation of a combined SO_2/NOx removal pilot plant using SCR technology (1MW size), at Tampa Electric Company's Big Bend Station.
- Member of the EPRI's Environmental Control Systems Task Force, guiding R&D for SO_2, NO_X and particulate control technologies, including flue gas desulfurization, fluid bed boiler SO_2, NO_X, and particulate controls, selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), urea injection, and low-NO_X burners.