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

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FOR

POWDER RIVER BASIN RESOURCES COUNCIL

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I. INTRODUCTION

This report applies a structured analysis procedure developed by the U.S. Environmental Protection Agency ("EPA") to the evaluation of best available control technology ("BACT") for the Dry Fork Station power plant. EPA's procedure, known as a five-step "top-down" BACT determination, has been applied to two distinct air pollution control technologies applicable to the proposed coal-fueled power plant – integrated gasification combined cycle ("IGCC") technology and pulverized coal combustion ("PC") technology – and the availability, technical feasibility and cost-effectiveness of air pollution control for each technology has been evaluated based on data compiled from publically available sources. The analysis indicates that IGCC would have air pollutant emissions significantly lower than those specified in the existing air quality permit for the Dry Fork Station, and is an available, technically feasible, and cost-effective option for the proposed facility.

This report was prepared by Mike Fowler, Technology Coordinator for the Coal Transition Project of the Clean Air Task Force ("CATF"). CATF is a national non-profit organization dedicated to restoring clean air and healthy environments through scientific research, public education, and legal advocacy. Controlling power plant air pollution has been the major focus of CATF since its founding in 1996.

This report was prepared at the request of attorneys representing Powder River Basin Resources Council ("PRBRC") in the Dry Fork Station air permit proceeding. It has been provided to PRBRC by Mike Fowler of CATF without charge, and Mike Fowler has received no compensation from PRBRC or their attorneys for preparation of this report.

II. SUMMARY OF AUTHORS EXPERIENCE AND QUALIFICATIONS

The author's full legal name is Michael Sergio Foreman-Fowler, although for business purposes he is generally known only as Mike Fowler. The author has been employed by CATF since March, 2007, where his responsibilities include preparation of expert reports on air quality impacts of IGCC and PC technology and environmental advising and facilitation of IGCC projects. Prior to joining CATF, from October, 2001 to January, 2007 Mr. Fowler was employed by the Air Quality Bureau of the New Mexico Environment Department ("NMED"), where he was an Air Permitting Specialist, a Supervisor in the New Source Review Section, and an Enforcement Manager. Before joining NMED Mr. Fowler worked for one year as a staff engineer at environmental consulting companies in Albuquerque, New Mexico, and for three years as a project scientist in the Division of Applied Sciences at Harvard University.

Mr. Fowler holds an A.B. degree in Physics from Harvard College, a Master's Certificate in Atmospheric and Oceanic Sciences from the University of Colorado at Boulder, and an M.S. degree in Aerospace Engineering Sciences from the University of Colorado at Boulder. A copy of Mr. Fowler's resume is included as Exhibit I to this report.

While employed by NMED Mr. Fowler's responsibilities included review of New Source Review and Title V air quality permit applications and preparation of air quality permits, supervision of staff performing air quality permit review functions, and management of an air quality inspection and enforcement group. In those roles Mr. Fowler provided testimony in federal court on incorporation of federal New Source Performance Standards into the Title V Operating Permit for a large coal-fired power plant, provided testimony before an administrative hearing on EPA's proposed mercury regulations for coal-fired power plants, and provided testimony in an NMED administrative hearing related to excess emissions from natural gas processing plants. While at NMED Mr. Fowler also was lead air permit reviewer for an application for a PC power plant for which NMED required consideration of IGCC in the BACT analysis.

In March, 2008 Mr. Fowler described a procedure for side-by-side consideration of PC and IGCC coal technologies in an example BACT analysis presented to the Gasification Technologies Council workshop in Tampa, Florida.

III. SUMMARY OF METHODS AND FINDINGS

This report evaluates the availability and cost-effectiveness of IGCC as an option for reduction of SO2, NOx, particulate matter, CO, and VOC from the Dry Fork coal-fueled power plant near Gillette, Wyoming based on EPA's top-down BACT procedure, publically available data, and the author's experience and judgment. The evaluation reveals that IGCC is commercially available, technically feasible, and would emit roughly 3,000 tons per year less pollution than the PC plant currently permitted for construction, at an incremental cost of less than $10,550 per ton of pollutant reduction. This incremental cost is comparable to the $9,926 per ton of SO2 previously required by Wyoming DEQ in the BACT evaluation for the Dry Fork plant. The report further evaluates the potential for CO2 emissions reductions at Dry Fork, and concludes that CO2 capture and storage ("CCS") is possible at commercial-scale for an IGCC plant there.

IV. REQUIREMENTS OF A 'TOP-DOWN' BACT ANALYSIS

The federal Clean Air Act ("CAA" or "the Act") defines BACT as:

> an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.

CAA Section 169(3) (42 U.S.C. §7479(3), emphasis added).

In order to facilitate appropriate application of the statutory criteria for BACT in real-world air quality permit evaluations EPA has developed a five-step "top down" BACT determination procedure. The procedure is described in detail in EPA's 1990 Draft New Source Review Workshop Manual ("NSR Manual, or "NSRM"). The NSRM method is widely used by EPA and state air pollution control agencies when evaluating BACT for new facilities.[1] It is used in Wyoming.[2]

There are five basic steps in the top-down procedure for BACT determination, each consisting of several key elements. Step 1, in which all potentially applicable control technologies are identified and listed, begins to address the statutory requirement for availability of control options, including alternative production processes with lower emissions. Step 2, in which the technical feasibility of each control option is considered, refines the availability assessment. In Step 3, attributes of the available options are tabulated, and in Step 4, the statutory requirement to consider "energy, environmental, and economic impacts" is implemented in part. This is where costs of each control option are properly considered. In Step 5, BACT is selected as the emission limit associated with the lowest emitting available control technology achievable for the source for which energy, environmental, and economic impacts are not unreasonable. According to EPA:

> In brief, the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent--or "top"--alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

NSRM at B.2.

V. <u>TOP-DOWN BACT EVALUATION FOR THE DRY FORK STATION</u>

The author has applied the five-step top down approach of EPA's NSRM to the control technology determination for the Dry Fork Station. The determination compares the emissions and costs of a pulverized coal power plant at the Dry Fork site to an IGCC power plant at the same site. Results indicate that an IGCC would emit less air pollution than the PC plant permitted for Dry Fork and that the air pollution control costs of IGCC are not unreasonable. The

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[1] According to the Environmental Appeals Board at EPA: "EPA recommends use of the NSR Manual methodology because it provides for application of all of the BACT regulatory criteria through a step-wise framework, that if followed, should yield a defensible BACT determination." See Knauf Fiber Glass, GmbH, 8 EAD 121, 129 n. 13 (EAB 1999).

[2] See, for example, "In the Matter of a Permit Application (AP-3546) from Basin Electric Power Cooperative to Construct a 385 MW Pulverized Coal Fired Electric Generating Facility to be Known as Dry Fork Station".

details of the analysis procedure, and results for Dry Fork, are discussed below.

Step 1 – Identify All Control Technologies

In Step 1 of the BACT analysis, all available air pollution control options with a practical potential for application to the source in question must be listed. Available and potentially applicable control options must include production processes, such as IGCC, that can reduce emissions. According to EPA:

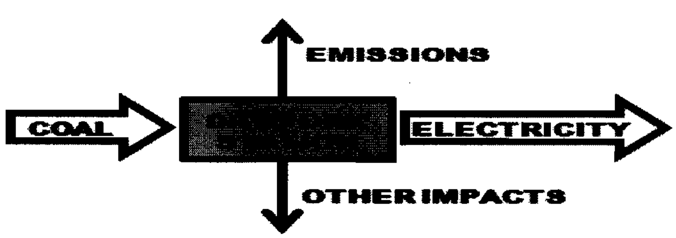
> The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation.

NSRM at B.5 (emphasis added).

Within EPA's top-down framework of the NSRM potentially applicable control alternatives are categorized as 'inherently lower-emitting' (such as production process that result in lower emissions), as 'add-on controls' (such as scrubbers and fabric filters) and as combinations of inherently lower-emitting and add-on controls, and the NSRM directs that the analysis "should consider potentially applicable control techniques from all three categories." NSRM at B.10 (emphasis added). NSRM further directs that inherently lower-emitting process should be considered based on "demonstrations made on the basis of manufacturing identical or similar products from identical or similar raw materials or fuels." NSRM at B.10 (emphasis added).

Applying EPA's top-down framework and the BACT requirements of the Clean Air Act to electric power generation using coal fuel leads directly to the conclusion that all processes for transforming the chemical energy of coal into electricity should be considered in the top down analysis. This is depicted schematically in Figure 1-1 below, where any modification to the grey shaded box (representing the production process) that can reduce emissions (represented by the vertical arrow) must be considered in the top-down BACT evaluation for a coal-fueled electric plant.

Figure 1-1 – Schematic Illustration of Coal-to-Electricity Production Process



This point bears emphasizing. The potential for inclusion of IGCC in BACT analysis for coal-fueled power plants was clearly recognized by the U.S. Congress at least as far back as 1977. At that time Kentucky Senator Walter Huddleston proposed adding the phrase "innovative fuel combustion techniques" to the scope of pollution control options under the existing Clean Air Act definition of BACT, and his language has carried through to this day. Senator Huddleston said:

> The definition in the committee bill of best available control technology indicates a consideration for various control strategies by including the phrase "through application of production process and available methods, systems, and techniques, including fuel cleaning or treatment." And <u>I believe it is likely that the concept of BACT is intended to include such technologies as low Btu gasification</u> and fluidized bed combustion. But, this intention is not explicitly spelled out, and I am concerned that without clarification, the possibility of misinterpretation would remain.
>
> It is the purpose of this amendment to <u>leave no doubt that in determining best available control technology, all actions taken by the fuel user are to be taken into account</u>- be they the purchasing or production of fuels which may have been cleaned or up-graded through chemical treatment, <u>gasification</u>, or liquefication; use of combustion systems such as fluidized bed combustion which specifically reduce emissions and/or the post-combustion treatment of emissions with cleanup equipment like stack scrubbers.

123 Cong. Rec. S9434-35 (June 10, 1977)(debate on P.L. 95-95)(emphasis added).

Consideration of IGCC in BACT analyses for coal-fueled power plants is required by the states of Illinois, Michigan, and New Mexico. Detailed evaluation of multiple designs for generating electricity from coal, including IGCC and circulating fluidized bed plants, is explicitly required in New Mexico. See Exhibit II, letter from Mike Fowler, NMED, to Larry Messinger, Mustang Energy Company, August 29, 2003. According to Sandra Ely, former Chief of the NMED Air Quality Bureau: "NM sees IGCC as an innovative lower emitting technology that the Clean Air Act intends to be included as a part of the BACT analysis for a new coal fired power plant."[3]

<u>IGCC's Practical Potential for Emissions Control</u>

Although the details of the electric production process differ in some respects, IGCC and PC plants share many similarities and ultimately both are designed and intended to harness the energy in coal for use in generating electricity. In a PC power plant coal is pulverized and then combusted to release heat which is used to produce steam and generate electricity using a steam turbine generator set. In an IGCC power plant coal is pulverized and then "gasified" –

[3] See "IGCC: Policy Implications in New Mexico", presentation to GTC Workshop, Tampa, Florida, March, 2006.

chemically converted into a clean, gaseous fuel called 'syngas' - and 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. In an IGCC plant, however, most of the coal's original energy is contained in the syngas, which is burned in a combined cycle combustion turbine generator set (almost identical to those using natural gas as fuel) to generate more electricity.[4] Both PC and IGCC power plants have equipment for coal storage, coal handling, coal preparation, production of steam, and steam turbine generator sets. IGCC plants have additional equipment for combustion of syngas in a gas turbine generator. Emissions from IGCC and PC plants are regulated under the same subpart of EPA's New Source Performance Standards.[5]

IGCC is not a new technology. Gasification has its roots in the production of "town gas" for lighting in the 18th century and early chemical and fuel production plants in the 1930s. Early modern gasification projects include the Sasol coal gasification systems in South Africa, the Great Plains Synfuels coal gasification plant in North Dakota, and the Cool Water IGCC near Barstow, California. At present there are roughly 417 gasifiers operating at 138 different plants worldwide with a capacity of approximately 56,000 MW (thermal). These plants operate primarily on coal (55%) and petroleum residue (32%) and produce chemicals (44%), liquids fuels (30%), electric power (18%), and fertilizer. Of the 138 gasification plants operating worldwide 19 are in North America (9 in Texas, 3 in Louisiana, and 1 each in Florida, Tennessee, Indiana, Kansas, North Dakota, Delaware, and Canada).[6] While not all of these gasifiers are used with power generation, there is significant experience operating combustion turbines on syngas, and GE combustion turbines alone have accumulated close to one million operating hours on syngas.[7]

Modern IGCC are relatively new, however, and there are currently only 16 IGCC operating worldwide, with a net installed electrical generation capacity of 3,870 megawatts ("MW"). These projects are listed in Table 1-1 below.

Table 1-1, IGCC Operating Worldwide[8]

Plant	COD	Size (MW)	Feed	Other Products
Nuon (Netherlands)	1994	250	Coal	-
Wabash (Indiana)	1995	250	Coal/Coke	-

[4] In GE Energy's 770 MW (gross) IGCC "reference plant" design, slightly less than 40% of the gross output is produced by the steam turbine operating in a Rankine thermodynamic cycle; approximately 60% is produced by the combustion turbines in a Brayton thermodynamic cycle.
[5] See 40 CFR Part 60, Amendments to New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units and Industrial-Commercial-Institutional Steam Generating Units; Final Rule, 72 F.R. 113.
[6] Presentation by Jim Childress to Gasification Technologies Council workshop in Indianapolis, IN, June, 2007.
[7] See Testimony of Dr. Norman Shilling, GE Product Line Leader for IGCC, before the Indiana Utility Regulatory Commission, Cause No. 43144, filed October 24, 2006, at page 6.
[8] Adapted from *Gasification – Versatile Solutions*, presentation by Gary Stiegel, US DOE, 2006. Note that Swartze Pumpe (Germany) may no longer be operating.

Plant	COD	Size (MW)	Feed	Other Products
Tampa Electric Polk 1 (Florida)	1996	250	Coal/Coke	-
Frontier Oil (Kansas)	1996	45	Coke	Cogen
SUV (Czech Republic)	1996	350	Coal	Cogen
Swartze Pumpe (Germany)	1996	40	Coal	Methanol
Shell Pernis (Netherlands)	1997	120	Tar	Cogen, H2
Puertollano (Spain)	1998	320	Coal/Pet Coke	-
ISAB (Italy)	2000	510	Asphalt	-
Sarlux (Italy)	2001	545	Tar	Steam, H2
Exxon Chemical (Singapore)	2001	160	Tar	Cogen
API Energia (Italy)	2001	280	Tar	Steam
Valero Refining (Delaware, USA)	2002	160	Coke	-
Nippon Refining (Japan)	2003	340	Asphalt	-
Eni Power (Italy)	2006	250	Asphalt	-
Nakoso (Japan)	In startup	250	Coal	-

In addition to these plants the 160 MW Louisiana Gasification Technologies Incorporated ("LGTI") IGCC operated from 1987 to 1995 in Plaquemine, Louisiana using Westinghouse combustion turbines and the E-Gas gasification technology now owned by ConocoPhillips Company. Prior to closure this plant gasified 3.7 million tons of sub-bituminous coal from the Rochelle Mine in Wyoming's Powder River Basin.

The operational experience of the 16 plants listed in Table 1-1, 9 of which operate on solid fuel such as coal, two of which operate with a "dual-train" configuration with output in excess of 500 MW, and totaling roughly 123 years, is sufficient to support a conclusion that IGCC has the 'practical potential' for application to coal-fueled power plants in the United States. The operational experience of the LGTI IGCC further supports this conclusion for the particular case of a plant utilizing sub-bituminous coal from Wyoming.

Air Pollutant Emissions from IGCC Power Plants

Air pollutant emissions from IGCC are generally lower than emissions from pulverized coal power plants. In Table 1-2 below the emissions of SO2, NOx, particulate matter, CO, and VOC of the Dry Fork Station, as currently permitted, are compared to past actual emissions from the Tampa Electric IGCC in Florida and to emissions levels authorized for the Christian County Generation, LLC IGCC permitted in June, 2007 in Illinois. Also included in the table are emissions authorized for the Duke Energy Indiana Edwardsport Generating Station IGCC, permitted in January, 2008, and emission limit levels from air quality permit applications for the Excelsior Energy Mesaba IGCC in Minnesota (application of June, 2006) and the Appalachian Power Company Mountaineer IGCC in West Virginia (application of October, 2006). All of these IGCC except Mesaba operate or will operate on feed-stocks (bituminous coal and petcoke) with sulfur content much higher than that from the Dry Fork mine. The Mesaba project will utilize Power River Basin sub-bituminous coal. Also included in the table are EPA reference emissions levels for a hypothetical IGCC operating on sub-bituminous coal.[9]

Table 1-2 – Dry Fork Station Emission Comparison

Plant Name and Data Source		Emissions[a,b] (in lb/MMBtu coal feed)				
Plant	**Source**	**SO2**	**NOx**	**PM[c]**	**CO**	**VOC**
Dry Fork PC	Permit	0.070	0.05	0.012 (f)	0.15	0.004
Taylorville IGCC	Permit	0.015	0.027	0.006 (f)	0.038	0.001
Edwardsport IGCC[g]	Permit	0.014	0.083	0.013 (f+c)	0.033	0.001
Mountaineer IGCC	Application	0.020	0.058	0.006 (f)	0.032	0.001
Mesaba IGCC	Application	0.025	0.057	0.009 (f)	0.035	0.003
Mesaba IGCC[f]	Agency	0.010	0.011	0.009 (f)	0.035	0.003
Polk IGCC	Actual	0.128[d]	0.044[d]	0.004 (f)	0.003	0.000
EPA IGCC	Study	0.012	0.044	0.007 (f)	0.03	0.002

Notes to Table 1-2: a) Emissions represent the author's calculation of values applicable during normal operation only; b) IGCC emissions include emissions from the combustion turbine stacks, sulfur recovery processes, and other miscellaneous sources but do not include material handling or cooling tower emissions; c) "PM" emissions include either filterable-only PM (designated with an (f)) or filterable and condensable emissions combined (designated with an (f+c)); d) Actual SO2 and NOx emissions from Polk were calculated based on emissions numbers reported to US EPA Clean Air Markets division for more than 7000 hours of operation in 2007, adjusted to include emission sources not reported to that program; e) Polk actual emission of PM, CO, and VOC are adapted from Tampa Electric Polk Power Station Integrated Gasification Combined Cycle Project, Final Technical Report, August, 2002; f) These emissions levels are consistent with a January 11, 2008 letter from the Minnesota Pollution Control Agency to Excelsior Energy indicating that Selexol and SCR should be reflected in BACT levels for the facility in its final Environmental Impact Statement;) Emissions for the Edwardsport IGCC do not reflect operation of the SCR to be built there.

The technical feasibility of IGCC for the Dry Fork site is assessed in Step 2 of this analysis; in Step 4 the potential cost differences between IGCC and PC are considered.

Step 2 – Eliminate Technically Infeasible Options

The second step of EPA's top-down procedure eliminates from further consideration those technologies identified in Step 1 that are not technically feasible for the proposed plant. EPA's technical feasibility assessment is based on whether a technology would work for the proposed facility, and is not based on the costs of that control (which are addressed in subsequent steps). EPA's approach to technical feasibility is three-pronged: 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.[10]

[9] See "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies", EPA, July, 2006.

[10] In cases where a technology has not been demonstrated in that sense the evaluation depends on availability and applicability. According to EPA "A technology that is available and applicable is technically feasible," NSRM at B.17, and "a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term." See NSRM at B.17.

IGCC Demonstrations and Operating Experience

IGCC is a demonstrated technology because it has been installed and operated successfully.[11] Of the plants in Table 1-1 the author has personally toured the 250 MW coal-based Nuon IGCC in the Netherlands, the 250 MW coal- and petcoke-based Wabash IGCC in Indiana, the 250 MW coal- and petcoke-based Polk IGCC in Florida, and the 528 MW asphalt-based ISAB IGCC in Italy. Data presented to the author during those visits or publically available indicates that:

- For the 9 year period of 1998 through 2006 availability of the Polk IGCC power block was always in excess of approximately 88% except for only one year (2003) when availability was approximately 85%. For the 3 year period of 2004 through 2006 annual availability on syngas has been roughly 80%. See Exhibit III.

- For the years of 2000, 2001, 2002, 2003, 2006, and 2007 (through June) annual availability of syngas at the Wabash IGCC never fell below approximately 70%. See Exhibit IV.

- For the 5 year period of 2002 through 2006 the annual capacity factor of the ISAB IGCC in Italy never fell below 85%, of which never less than approximately 95% was achieved using syngas (with the balance provided by diesel fuel). See Exhibit V.

- For the 8 year period 1998 through 2006 the annual capacity factor of the power block of the Nuon IGCC in the Netherlands never fell below approximately 80% and was regularly in excess of 80%. Data for this period indicate that availability on syngas has improved steadily. See Exhibit VI.

These data compare favorably with capacity factor data for existing United States coal-fired power plants, which indicate that for all plants coming on-line in the US after 1980 average capacity factor through 2005 was 77%, while the average for plants coming on-line after 1991 has been 83%, and the average (for plants after 1981) in the Western Systems Coordinating Council (WSCC, now part of the Western Electricity Coordinating Council, which includes Wyoming), has also been 83%.[12] For the next generation of IGCC expected availabilities are even higher. Tampa Electric Company's recent proposal for an IGCC in Florida, for example (later cancelled due to concerns about carbon dioxide requirements) anticipated an overall annual equivalent availability factor of 96%, with an annual EAF of 86% anticipated for syngas-only operation.[13]

[11] According to EPA, "if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible". See NSRM at B.17.
[12] Data on coal-fired generation station capacity factors compiled by CATF and MSB Energy Associates, Middleton, WI, based on data in United States Department of Energy, Energy Information Administration, Form 767 for 2005.
[13] See the prepared direct testimony of Michael R. Rivers, Director, Engineering and Construction, Tampa Electric Company, before the Florida Public Service Commission, submitted July 20, 2007, In Re: Tampa Electric's Petition

IGCC is also both available and applicable to coal-fueled electricity generation at the Dry Fork site. For assessing availability at this stage of the BACT analysis EPA lists 6 stages of technology development ('concept stage', 'research and patenting', 'bench scale or laboratory testing', 'pilot scale testing', 'licensing and commercial demonstration', and 'commercial sales') (see NSRM at B.17) and states that "A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development." NSRM at B.18 (emphasis added).

Several different consortiums offer IGCC for licensing and commercial sales under a number of different contract mechanisms. These arrangements are described in detail below.

Commercial Availability of ConocoPhillips IGCC Technology

IGCC are available commercially on a turnkey basis from an alliance of ConocoPhillips, owner of the E-Gas coal gasification technology used in the LGTI and Wabash IGCCs, and Fluor, a large energy project engineering and construction firm.[14] In 2006 this alliance joined forces with Siemens to offer a 606 MW IGCC for Excelsior Energy's Mesaba project in Minnesota. For Mesaba the companies formed an engineer-procure-construct ("EPC") consortium in which Siemens will provide the project power block, ConocoPhillips will supply the E-Gas gasification technology and related design services, and Fluor will lead the consortium in detailed design, engineering, procurement, and construction under a firm price lump sum turnkey contract. Project performance and schedule guarantees will be shared by Fluor and Siemens.[15]

The Mesaba project design calls for 100% Powder River Basin sub-bituminous coal feedstock (or Power River Basin sub-bituminous coal blended with Illinois bituminous coal and up to 50% petroleum coke)[16] using E-Gas technology at a scale 10-30% larger than used at the existing Wabash IGCC. According to ConocoPhillips the Mesaba project is not a novel design, however, as the LGTI IGCC successfully gasified approximately 3.7 million tons of sub-bituminous coal from the Rochelle Mine in the Powder River Basin, at a rate of 2,400 tons per day, between 1987 and 1995.[17]

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to Determine Need for Polk Power Plant Unit 6, page 15. The improvement in availability relative to the existing Polk IGCC is due in part to removal of convective syngas coolers in the new GE reference plant design.

[14] In May, 2004 ConocoPhillips and Fluor announced a Gasification Technology Alliance under which "Fluor and ConocoPhillips will cooperate to provide comprehensive offerings for the licensing, development, engineering, procurement, construction and operations and maintenance of integrated gasification facilities for production of a wide range of energy and chemical products," including "turnkey contracts for construction of solid fuel gasification facilities". See May 24, 2004 ConocoPhillips News Release "ConocoPhillips and Fluor Announce Gasification Technology Alliance".

[15] See "Joint Application to the Minnesota Public Utilities Commission for the Following Pre-Construction Permits: Large Electric Generating Plant Site Permit, High Voltage Transmission Line Route Permit and Natural Gas Routing Permit", dated June 16, 2006, page 30.

[16] See the Joint Application, page 22 and page 159.

[17] See Rebuttal Testimony of Thomas A. Lynch, Project Development Manager, ConocoPhillips Company, Before

Commercial Availability of GE IGCC Technology

IGCC are available commercially on a turnkey basis, including guarantees and warranties, from an alliance of GE Energy, owner's of the gasification technology used in the Polk IGCC, and Bechtel, a large EPC firm.[18] American Electric Power has chosen this alliance to construct a 629 MW IGCC at its existing Mountaineer plant in Mason County, West Virginia, and Duke Energy has chosen the alliance to build a 630 MW IGCC at their existing generating station in Edwardsport, Indiana. For the Mountaineer IGCC AEP chose a strategy in which "GE/Bechtel will act as a single contractor, having essentially joint and several liability for performance of the EPC contract" in which "performance, operating flexibility, and timely completion" will be assured by "things such as emissions, output, heat rate, turndown and ramp rate".[19] The current capital cost estimate for the Mountaineer IGCC is $2.23 billion (approximately $3,545/kW).[20]

In March, 2008 the West Virginia Public Service Commission approved AEP's request for authorization to construct the Mountaineer IGCC facility, noting that "given the number of years that IGCC has been used in the chemical industry and the success of IGCC technology at TECO/Polk, the Commission concludes that there has been sufficient experience and information to support APCo's position that the technology can be operated successfully on a commercial scale."[21] In November, 2007 the Indiana Utility Regulatory Commission approved Duke Energy's proposal for the Edwardsport facility. In its order the IURC noted "we find the Company's $1.985 billion cost estimate to be reasonable" and "We find that the IGCC Project is technically feasible and commercially reasonable and is expected to be a reliable baseload generating station".[22] The Edwardsport IGCC will not be constructed as a lump-sum turn-key

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the Minnesota Office of Administrative Hearings, October 10, 2006, pages 3 – 5.

[18] According to GE: "GE and Bechtel have formed an IGCC alliance to offer a turnkey nominal 630 megawatt Reference Plant for the US Electric Generating Market" in which "GE and Bechtel offer their IGCC Reference Plant product by executing projects in consortium. Each project consortium offers the customer a seamless, integrated technical product based on the reference plant, and a commercial offering with appropriate guarantees and warranties." See testimony of Norman Shilling, Product Line Leader, GE Energy, before the Indiana Utility Regulatory Commission, submitted October 24, 2006, Cause Number 43114, pages 7 and 8.

[19] See direct testimony of William M. Jasper, Director – New Generation Projects, American Electric Power Company, Inc., before the West Virginia Public Service Commission, submitted June 18, 2007, page 14. See also Jasper's summary of the FEED study, in which he cites the following conclusions of the FEED: "the project is technically feasible and commercially reasonable" in which "AEP has taken a lump-sum turnkey approach." (Jasper testimony Exhibit 2 page 1), under which "one supplier will be responsible for the design, supply, construction, startup, testing, and warranties of all major equipment and supporting systems. This will allow substantially all of the facility to be covered by one set of guarantees. These guarantees will have much higher limits, and be more comprehensive than would be the case if equipment and systems were supplied on an individual vendor basis".

[20] See Direct Testimony of Phillip J. Nelson before the Virginia State Corporation Commission in Case No. PUE-2007-00068, Schedule 3. On April 14, 2008 the Virginia SCC denied AEP's application for this plant. News media report, however, that AEP intends to seek reconsideration of that decision (see, e.g., West Virginia MetroNews, April 15, 2008).

[21] Public Service Commission of West Virginia, Case No. 06-0033-E-CN, Order of March 6, 2008, page 77.

[22] Indiana Utility Regulatory Commission, Cause No. 43114, Approval of November 20, 2007 at pages 36 and 38.

project, and costs will be slightly lower than at Mountaineer ($3,151/kW).[23]

At present there do not appear to be IGCC projects moving forward based on GE technology for sub-bituminous coal. In 2007 GE purchased a coal feed system that is expected to enable to the GE gasification system to utilize Powder River Basin coal, however. GE Energy responded to a request for proposals from PacificCorp for an IGCC to be located at their Jim Bridger station in Wyoming, but the terms of that response are not publically available.[24]

Commercial Availability of Shell IGCC Technology

Shell gasification technology is also available commercially for the Dry Fork site. In November, 2004 Black & Veach and Uhde announcement an alliance to offer EPC services for IGCC plants utilizing Shell gasification technology. According to the news release "The alliance will 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."[25] For the Dutch utility N.V. Nuon's proposed 1200 MW IGCC Udhe GmbH has been contracted to provide early development work based on the Shell technology.[26] Shell also responded to the PacifiCorp RFP.

Commercial Availability of IGCC from Other Suppliers

Recently Mitsubishi has entered the IGCC market with an air-blown gasification and combustion turbine offering. According to an October 15, 2007 presentation by MHI, MHI provides gasification technology developed from their proven boiler and water wall heat recovery design, OEM for gasifier, gas turbine, steam turbine, and EPC contractor "to wrap up the whole project".[27] MHI has been selected by NRG Energy, Inc. for an IGCC project under development in Towanda, New York.[28]

In 2006 Siemens AG acquired the Future Energy coal gasification business of the Swiss Sustec Group, and began development of an IGCC reference plant based on scale-up of the Sustec - Future Energy gasifier used at the Swartze Pumpe IGCC in Germany. Combustion turbines based on Siemens technology were used at the LGTI IGCC (Westinghouse brand at that time) and are in use at the ISAB and Nuon IGCC, and Siemens is currently supplying several gasifiers for chemical production plants in China. Siemens responded to the PacifiCorp RFP

[23] Indiana Utility Regulatory Commission, Cause No. 43114, Approval of November 20, 2007 at page 32.
[24] "IGCC Working Group, Jim Bridger IGCC Study", presentation by PacifiCorp, March 27, 2008.
[25] See the November 29, 2004 press release "BLACK & VEATCH AND UHDE ANNOUNCE ALLIANCE TO PURSUE CLEAN COAL PROJECTS: Companies to leverage Shell coal gasification technology".
[26] See the April 10, 2007 press release "Dutch utility company Nuon awards Uhde contract for coal gasification plant".
[27] See "Deployment of Air-Blown IGCC Technology with Carbon Capture", Koichi Sakamoto, MHI Project Director, presentation to Gasification Technologies Council meeting in San Francisco, CA, October 15, 2007, and the accompanying video available at www.gasificaiton.org.
[28] See the November 2, 2007 NRG Energy third quarter 2007 financial results presentation at www.nrgenergy.com.

with an integrated IGCC plant proposal, and Siemens IGCC is considered commercially available for the Dry Fork plant.

Applicability of IGCC Technology to the Dry Fork Site

IGCC is applicable to a 385 MW plant intended to utilize sub-bituminous coal from Wyoming's Powder River Basin at 4,250 feet elevation. According to EPA, under the technical feasibility assessment an available technology is 'applicable' "if it can reasonably be installed and operated on the source type under consideration," NSRM at B.17, and:

> For process-type control alternatives the decision of whether or not it is applicable to the source in question would have to be based on an assessment of the similarities and differences between the proposed source and other sources to which the process technique had been applied previously.

NSRM at B.19 (emphasis added).

There are two distinctive elements of the Dry Fork plant proposal that could impact applicability of IGCC there. These are elevation and coal type. Neither of these differences represents a technical impediment to successful operation of an IGCC at Dry Fork, however. These differences may impact the relative cost of IGCC for Dry Fork, which is not properly considered in the technical feasibility assessment.[29]

Among the 'available' IGCC technologies noted above the ConocoPhillips offering is the most obviously applicable to the Dry Fork site as the ConocoPhillips technology has successfully gasified an almost identical coal in an IGCC context, which is not true of the GE, Shell, or Mitsubishi offerings (although the Shell gasification technology has been used for other purposes with low-grade coals in China and the Mitsubishi gasifier has been tested on and is offered for use with PRB coal). In addition, for the Masaba project ConocoPhillips technology will be used on PRB coal almost identical to the Dry Fork coal.

The effects of elevation on IGCC performance are significant, but relatively straightforward. At higher elevations air is less dense, and 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. The effect is analogous to the effect seen in automobiles while driving at high elevation. In addition to combustion turbine effects, the air separation unit of an IGCC (used to supply oxygen to the gasifier) must be slightly larger for units operating at high elevation. Overall plant energy efficiency is not effected by elevation, however, because when less air mass is used by the combustion turbine less fuel (in the form of syngas) is also used. Engineering studies by ConocoPhillips and WorleyParsons indicate that an IGCC operating at 5000 feet elevation on western sub-bituminous coal would produce roughly 13%

[29] According to EPA "Where the resolution of technical difficulties is a matter of cost, the applicant should consider the technology as technically feasible." NSRM at B.19.

less output than at sea level, but would have an almost identical heat rate.[30]

It is also worth noting that regulators in at least one state have determined that IGCC is technically feasible based on EPA's criteria. In New Mexico in 2003, a 300 MW IGCC using high ash sub-bituminous coal at 7000 feet elevation was found to be technically feasible by the permitting agency.[31]

In the end, the technical feasibility assessment answers the common-sense question "will the technology work?" According to EPA:

> A demonstration of technical infeasibility should be clearly documented and should show, <u>based on physical, chemical, and engineering</u> principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.

NSRM at B.7 (emphasis added).

IGCC passes the test for technical feasibility at the Dry Fork site. To the extent that technical issues remain after applying this test for IGCC at Dry Fork the issues are properly addressed as issues of cost, not as issues of technical feasibility. Basin Electric's own analysis of IGCC for Dry Fork supports this conclusion: in that analysis, Basin stated "The IGCC option is probably technically feasible for use in reducing SO2, NOx, PM, CO and VOC emissions from the new unit".[32]

<u>Step 3 – Rank Remaining Control Technologies by Control Effectiveness</u>

In Step 3 of a top-down BACT analysis the emissions performance, costs, and other attributes of each pollution control option are tabulated in units that facilitate comparison between the options. The author has developed an illustrative comparison for the Dry Fork site, based on information supplied by Basin Electric in their air quality permit application for Dry Fork and other sources. Details of this comparison are provided in Exhibit VII. A summary is provided in Table 3-1 below.

<u>Table 3-1 Summary of Emissions and Cost Data for Dry Fork BACT</u>

Attribute	**PC**	**IGCC**
SO2 emissions, lb/MMBtu coal feed	0.070	0.010
NOx emissions, lb/MMBtu coal feed	0.050	0.011
Filterable PM emissions, lb/MMBtu coal feed	0.012	0.006

[30] See "CO2 Capture: Impacts on IGCC Plant Performance in a High Elevation Application using Western Sub-Bituminous Coal", WorelyParsons and ConocoPhillips to Gasification Technologies Council, October, 2007.
[31] According to EPA, "In practice, decisions about technical feasibility are within the purview of the review authority." NSRM at B.19.
[32] "Coal Power Plant Technology Evaluation for Dry Fork Station", prepared for Basin Electric Power Cooperative by CH2M Hill, November 1, 2005, page 48.

Attribute	PC	IGCC
CO emissions, lb/MMBtu coal feed	0.150	0.035
VOC emissions, lb/MMBtu coal feed	0.004	0.001
Plant capital cost, $/kW	$3,668	$4,769
Plant O&M cost, $1000/yr	$24,780	$26,010
Plant heat rate, Btu/kWh (HHV)	10,077	9,500

Details of the calculation include:

- For the PC plant, emissions levels and plant heat rate are taken directly from the existing Dry Fork Station air quality permit and the analysis provided by CH2M HILL, Inc. to Basin Electric dated June 26, 2007 ("Basin Report").

- For the IGCC plant, the PM, CO, and VOC emission rates are also taken directly from the Basin Report.

- The SO2 and NOx emission levels for the IGCC plant are taken from Excelsior Energy's air quality permit application for the Mesaba IGCC plant proposed for northeastern Minnesota, revised in accordance with January 11, 2008 comments from the Minnesota Pollution Control Agency. In those comments the MPCA stated that the environmental impact statement ("EIS") for the Mesaba facility should include emissions levels for SO2 and NOx that reflect use of Selexol and SCR for control of SO2 and NOx. The resulting emissions levels for SO2 are 0.01 lb/MMBtu (20 ppmv syngas sulfur, down from 50 ppmv and 0.025 lb/MMBtu with use of MDEA solvent) and for NOx are 0.011 lb/MMBtu (3 ppmv stack NOx at 15% O2, down from 15 ppmv and 0.057 lb/MMBtu based on use of syngas dilution). These emissions levels are achievable: Selexol is currently used for sulfur removal at 56 industrial facilities world-wide, including the 280 MW API and 545 MW Sarlux IGCCs in Italy and the Coffeyville Resources ammonia production plant in Kansas, USA (which uses GE technology for coal gasification); SCR is used at the 510 MW ISAB IGCC in Italy and the 380 MW Negishi IGCC in Japan. The Selexol system at the Coffeyville plant reduces syngas total sulfur content to 3 ppmv; NOx emissions from the Negishi IGCC are reported to be 2.5 ppmv (corrected to 15% O2).[33]

- The heat rate for the IGCC plant is the same as the worst-case heat rate for Excelsior's Mesaba plant proposed for Power River Basin coal (9,500 Btu/kWh, partial slurry quench mode).

- Capital costs for the PC and IGCC plants are taken directly from the Basin Report,

[33] See "Syngas Treating for Stringent Product Specifications and CO2 Capture", UOP/Honeywell presentation to Gasification Technologies Council, October, 2007 and Evaluation of Alternative IGCC Plant Designs for High Availability and Near Zero Emissions, EPRI, 2005, page 3-1.

despite the fact that these costs appear to be somewhat higher than for other recent plants, especially for the IGCC plant (compare Duke Energy's Cliffside pulverized coal plant in North Carolina, where construction costs are reported to be approximately $3,000 per kW, to the Mountaineer IGCC at $3,545/kW and Edwardsport IGCC at $3,151/kW).[34]

- 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).

- For the IGCC plant the base O&M cost, adopted directly from the Basin Report, is adjusted upward by a line-item addition for the operation and maintenance of the Selexol and SCR ($4.1 million per year, including electrical demand for the SCR system) based on data provided in EPA's Footprints Report, escalated by +33%.

- For the PC plant, O&M costs are adjusted upwards from the values provided in the Basin Report to make them consistent with costs published in EPA's Footprints Report (resulting in O&M cost for the PC plant that are 95% of the IGCC O&M costs).

- For both the PC and IGCC plants the fuel cost is adjusted upwards from the value cited in the Basin Report by +64% to reflect recent reports of rising Powder River Basin coal prices.

- For both the PC and IGCC plants the annual capacity factor is taken to be 85%. This value is consistent with regional averages for new coal plants, and is achievable by both technologies. Use of natural gas backup fuel, while adding value to the IGCC plant in the form of enhanced availability, is not considered here.

- The capital cost recovery factor for both the PC and IGCC plants is taken directly from the Basin Report (6% annual interest rate, 42-year period).

<u>Step 4 – Evaluate Most Effective Controls and Document Results</u>

The data presented in Table 3-1 and Exhibit VI can be used to derive an incremental cost effectiveness of the IGCC plant, compared to the PC plant, for Dry Fork. Incremental cost effectiveness is simply the difference in total annual cost for each technology, calculated using an equivalent uniform annual cost method and expressed in dollars, divided by the difference in emissions between the two technologies (expressed in tons). While EPA generally advises against undue reliance on increment cost effectiveness in BACT determinations, incremental cost

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[34] See "Rising Utility Construction Costs, Sources and Impacts", the Brattle Group, September, 2007, page 11.

effectiveness can provide a useful point of comparison between the technologies.[35]

Table 4-1 below summarizes the author's calculation of incremental cost effectiveness for IGCC at Dry Fork. Results are presented in terms of incremental cost effectiveness for SO2, NOx, PM, CO, and VOC combined, an approached that focuses on balanced control between the pollutants.[36] The overall incremental cost effectiveness of IGCC, at **$10,549/ton,** is reasonable and is similar to the incremental cost effectiveness level of $9,926/ton for SO2 that the Wyoming DEQ has already approved for the use of a spray dryer absorber at Dry Fork.[37]

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

Attribute	**PC**	**IGCC**	**Delta**
Annualized Capital Cost, M$/yr	$88.67	$115.27	$26.60
Annual Non-Fuel O&M Cost, M$/yr	$24.78	$26.01	$1.23
Annual Fuel Cost, M$/yr	$15.85	$14.94	($0.91)
Annual Cost, IGCC Selexol + SCR, M$/yr	-	$5.86	$5.86
Total Annual Cost, M$/yr	$129.30	$162.09	$32.78
Total Annual Emissions (tons/yr)	3,944	837	3,108
Total Incremental Cost Effectiveness ($/ton)			**$10,549**

The incremental cost of pollution reduction with IGCC can also be apportioned to each pollutant in accordance with EPA policy, with acceptable results (SO2 at $9,604 /ton, NOx at $10,485/ton, PM at $16,455 /ton, CO at $10,741/ton, and VOC at $11,152/ton).[38]

Other Impacts

In addition to cost-effective pollution reduction for SO2, NOx, PM, VOC, and CO, IGCC also offers advantages with respect to other environmental impacts. For mercury, carbon adsorption equipment can reduce emissions by 90%-95% on IGCC plants at approximately one tenth the cost of control in a PC plant.[39] Anecdotal evidence from the Eastman Chemical Corporation coal gasification plant in Kingsport, Tennessee, suggests that total mercury control using carbon adsorption on syngas there is even higher, in excess of 99%, and beyond conventional detection limits.[40]

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[35] According to EPA "undue focus on incremental cost effectiveness can give an impression that the cost of a control alternative is unreasonably high, when, in fact, the total cost effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs." NSRM at B.45 – B.46.

[36] See, e.g, NSRM at B.53.

[37] See WY DEQ analysis of Basin Electric Revised SO2 BACT analysis, at p. 3.

[38] See Memorandum from Brian L. Beals, EPA Region 4, to Edward Cutrer, Georgia Department of Natural Resources, March 24, 1997.

[39] See "The Cost of Mercury Removal in an IGCC Power Plant", presentation by Parsons to Gasification Technologies Public Policy Workshop, June 1, 2002.

[40] Comments of David Denton, Eastman Chemical Corporation, to Gasification Technologies Council workshop, Tampa, Florida, March 14, 2008.

Carbon Dioxide

An IGCC plant at the Dry Fork site would emit slightly less CO2, per unit of electricity supplied to the grid, than the PC plant currently proposed there. The difference is due to differences in efficiency between the two plant designs, and amounts to approximately 24 tons of CO2 per hour, or 6%.[41] Beyond this difference, however, IGCC also presents the opportunity to use proven technology to capture CO2 before it is emitted to the atmosphere, rending the CO2 available for storage or other uses rather than discharge. No such technology is currently used at commercial scale for CO2 capture from a PC plant.

On an IGCC plant, the MDEA, Selexol, and Rectisol solvents used to remove sulfur from coal-derived syngas can all absorb some fraction of the "native" CO2 that is present in syngas as a result of the gasification process. The existing MDEA system at the Polk 1 IGCC, for example, captures roughly three times more CO2 than H2S (on a volume basis). At the Polk 1 IGCC this CO2 is released along with SO2 from the stack of the SAP. Because capturing the "native" CO2 in syngas does not require any fundamental reworking of an IGCC plant, however, so-called partial capture of CO2 from an IGCC offers a way to reduce CO2 emissions for limited cost (provided a suitable storage reservoir for the CO2 is available). No combustion turbine modifications are required. Capture of 20% to 30% of the CO2 that would otherwise be emitted from an IGCC is possible today using this approach at an increase of approximately 10% on cost of electricity.[42]

For greater levels of CO2 capture on IGCC more complex plant changes are necessary. A water-gas shift reaction is used to produce syngas with a high concentration of CO2, which may be removed using an additional stage of MDEA, Selexol, or Rectisol. Similar systems have been employed by the petrochemical industry for decades to adjust the composition of chemical process streams. The Eastman Chemical Corporation gasification facility in Kingsport, TN, for example, uses coal-derived syngas followed by a shift reaction and Rectisol CO2 removal to produce syngas to exacting composition specifications. The CO2 so produced has been used in the past for industrial applications, but currently is being vented to the atmosphere.

The Great Plains Synfuels plant in Beulah, North Dakota and the Farmland refinery in Coffeyville, Kansas both gasify coal and use water-gas shift to adjust syngas composition to specifications determined by downstream needs. At Great Plains Synfuels, syngas is used to produce synthetic natural gas ("SNG") for sale into the interstate natural gas pipeline system. Following a shift reaction CO2 is removed by a Rectisol unit and is transported by pipeline to Weyburn, Canada, where it is used for enhanced oil recovery ("EOR").[43] Approximately two million metric tonnes of CO2 are produced and stored in this way each year. At Coffeyville, a

[41] A representative carbon-to-CO2 conversion efficiency of 95% is assumed for both plants.
[42] See "IGCC vs. Carbon", presentation by Norman Shilling to GTC Workshop, Tampa, Florida, March, 2008; see also prepared testimony of Douglas Cortez submitted to Indiana Utility Regulatory Commission, Cause No. 43114.
[43] See the October, 2004 presentation by Dakota Gasification Company titled "CO2 Recovery and Sequestration at Dakota Gasification Company".

shift reaction and CO_2 removal by Selexol™ are used on coal-derived syngas to produce a rich H_2 stream used for ammonia production at the facility.[44] Presently CO_2 produced in this way at Coffeyville is being vented, but Farmland recently announced an agreement with BlueSource, LLC to supply 650,000 metric tonnes per year of the CO_2 for use in EOR.[45]

Employing a shift reaction increases the H_2 content of the syngas presented to the combustion turbine in an IGCC system, but such changes are manageable with today's technology. According to GE, full-scale H_2 combustion validation testing of their IGCC "FB" combustion turbine was completed in 2006, and the 7FB IGCC turbine has been commercially offered for high hydrogen fuel generated from carbon capture.[46] Other GE turbines have also demonstrated reliable operation on high H_2 content fuels.

At present there are no CO_2 capture technologies employed at commercial scale on the exhaust of a PC power plant. Amine-based capture technologies and ammonia-based capture technologies, as well as oxy-combustion, may hold promise in the future, but the largest installations utilizing these technologies are a small fraction of the size of the Dry Fork power plant (the largest post-combustion amine system currently operating captures 800 tons of CO_2 per day – less than 10% of the emissions of the proposed Dry Fork plant – from the exhaust of a coal-fired boiler in Trona, California; the largest ammonia-based capture on a coal power plant exhaust is approximately 1.7 MWe, scheduled to begin testing in May, 2008 at the We Energies' Pleasant Prairie plant; current plans call for scale-up of oxy-combustion to the 30 MWth size by summer 2008).

Storage

Wyoming has ample opportunities for deep underground storage of CO_2 captured from coal power plants, with a CO_2 pipeline network already in place and expansion planned for the Power River Basin.[47] CO_2 injection for EOR is underway in the Salt Creek field and other areas of Wyoming, and estimates from the University of Wyoming suggest that CO_2 demand for enhanced oil recovery in the Power River Basin alone could amount to 236 – 354 million tons (approximately 50 years of output for two plants the size of Dry Fork Station).[48] CO_2 storage potential in other formations in Wyoming is much greater, exceeding 36 billion tons.[49] Once purchased for use in EOR CO_2 can be effectively isolated from the atmosphere, and more than 99% of CO_2 injected into properly selected formations is expected to remain in place for over

[44] See "Synthesis Gas Purification in Gasification to Ammonia/Urea Production", Fluor/UOP, 2004.
[45] See the August 21, 2007 news release by BlueSource.
[46] See "IGCC vs. Carbon", presentation by Norman Shilling to GTC Workshop, Tampa, Florida, March, 2008
[47] See, for example, "Wyoming Enhanced Oil Recovery Institute, Joint Producers Meeting, CO2 in Wyoming", presentation by Wyoming Pipeline Authority, June 26, 2007.
[48] See "CO2 Demand Estimates for Major Oil Fields in Wyoming", presentation by Shaochang Wo to Wyoming WORI Joint Producers Meeting, June 26, 2007.
[49] See "Presentation to the Joint Minerals and Economic Development Committee", Jim Steidtmann, Wyoming Enhanced Oil Recovery Institute, 26 September, 2007.

1000 years.[50]

Step 5 – Select BACT

According to EPA, "The most effective control alternative not eliminated in Step 4 is selected as BACT." NSRM at B.53. The results of Step 4, above, indicate that IGCC cannot be eliminated from BACT consideration at Dry Fork due to cost effectiveness.[51] IGCC also offers significant benefits for mercury and carbon dioxide control. Although these conclusions are based on a preliminary analysis, they strongly suggest that IGCC represents BACT for the Dry Fork Station.

[50] The Intergovernmental Panel on Climate Change describes annual leakage rates for CO2 used for EOR in a Rangely, Colorado field at less than 0.00076% per year, for example. For large-scale operational CO2 storage projects IPCC states: "assuming that sites are well selected, designed, operated and appropriately monitored, the balance of available evidence suggests the following: • It is very likely the fraction of stored CO2 retained is more than 99% over the first 100 years. • It is likely the fraction of stored CO2 retained is more than 99% over the first 1000 years." See IPCC, Special Report on Carbon Capture and Storage, 2005, p. 216 and p. 246.

[51] "To justify elimination of an alternative on these [cost] grounds, the applicant should demonstrate to the satisfaction of the permitting agency that costs of pollutant removal (e.g., dollars per total ton removed) for the control alternative are disproportionately high when compared to the cost of control for the pollutant in recent BACT determinations. Specifically, the applicant should document that the cost to the applicant of the control alternative is significantly beyond the range of recent costs normally associated with BACT for the type of facility (or BACT control costs in general) for the pollutant." NSRM at B.45.

VI. SIGNATURE PAGE

This document was prepared by Michael Sergio Foreman-Fowler, who is solely responsible for its content.

Michael S. Foreman-Fowler

Michael S. Foreman-Fowler

29 April 2008

Date

VII. LIST OF EXHIBITS

Exhibit I – Mike Fowler Resume (2 pages)

Exhibit II – NMED Letter (4 pages)

Copy of letter from Mike Fowler, New Mexico Environment Department, to Larry Messinger, Mustang Energy Company, dated August 29, 2003.

Exhibit III – Polk IGCC Availability History (1 page)

Excerpt from Testimony and Exhibit of Mark J. Hornick, General Manager – Polk and Phillips Power Stations, before the Florida Public Service Commission in Docket No. 070467-EI, In Re: Tampa Electric's Petition to Determine Need for Polk Power Plant Unit 6.

Exhibit IV – Wabash IGCC Availability History (1 page)

Excerpt from presentation by Phil Amick, ConocoPhillips, June 12, 2007, to Gasification Technologies Workshop, Indianapolis, Indiana, titled "Wabash River Coal Gasification Repowering Project".

Exhibit V – ISAB IGCC Capacity Factor History (2 pages)

Excerpt from presentation by ERG Energy to the author, October 8, 2007, titled "Delegation on Advanced Coal Technology, Carbon Capture and Storage, and Climate Policy".

Exhibit VI – Nuon IGCC Capacity Factor History (1 page)

Excerpt from presentation by Nuon energy to the author, October 10, 2007, titled "From Buggenum to Magnum, A Next Step in Energy Transition".

Exhibit VII – Incremental Cost Effectiveness Calculation (1 page)

RESUME of
Michael Foreman-Fowler

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EDUCATION

May 1998, **M.S., Aerospace Engineering Sciences**, University of Colorado, Boulder, CO
May 1998, **Master's Certificate, Atmospheric and Oceanic Sciences**, University of Colorado, Boulder, CO
June 1991, **B.A., Physics**, Harvard College, Cambridge, MA

PROFESSIONAL EXPERIENCE

March 2007 – Present, **Technical Coordinator, Coal Transition Project**
Clean Air Task Force, Boston, MA

Engineer responsible for development of technical testimony and advocacy positions on energy and climate related issues for a national non-profit environmental organization. Focus areas include fossil fuel combustion, coal gasification, and carbon dioxide capture and geological sequestration.

July 2006 – January 2007, **Policy Development Specialist**
New Mexico Environment Department, Air Quality Bureau, Santa Fe, NM

Technical specialist responsible for regulatory and air pollution emissions analysis, research, and development of recommended New Mexico Environment Department, Air Quality Bureau policies, guidance documents, and technical memoranda. Projects include policy development for oil and gas wellhead equipment in sensitive environments, an emissions monitoring protocol for flares, and development of a policy for relocation of portable sources.

March 2005 – June 2006, **Enforcement Manager**
New Mexico Environment Department, Air Quality Bureau, Santa Fe, NM

Manager responsible for overseeing and directing the work of five (5) environmental compliance specialists. Primary duties included ensuring New Mexico Environment Department conformity to US EPA's Compliance Monitoring System requirements for air quality inspections and ensuring that timely and appropriate enforcement actions resulted from discoveries of non-compliance. Supervisory duties included providing inspection and enforcement activity assignments, guidance, and direction to staff (and a front line supervisor), directing and ranking staff priorities, and tracking progress toward staff goals and objectives. Enforcement work involved extensive coordination with citizen environmental groups, US EPA, and the regulated community. Special contributions while Enforcement Manager included technical analysis and documentation of potential performance of sulfur dioxide, nitrogen oxides, and particulate matter emissions reductions technologies and related retrofit costs for a large coal-fired power plant and a compliance analysis of air pollution emissions due to equipment failures in the natural gas processing industry.

July 2003 – February 2005, **New Source Review Supervisor**
New Mexico Environment Department, Air Quality Bureau, Santa Fe, NM

Front-line supervising engineer responsible for overseeing three (3) air permitting specialists. Supervisory responsibilities included hiring staff, assuring timely and appropriate staff work products, evaluating staff performance, and supporting Bureau management in complex decision making (including revisions to air quality permitting regulations and development of staff performance evaluation measures). Special contributions while NSR Supervisor included evaluation of costs and emissions performance of clean coal technology in the best available control technology (BACT) analysis for a coal-fired power plant and development of State of New Mexico testimony regarding US EPA's proposed mercury control requirements for coal-fired power plants. Responsibilities also included continued work as an Air Quality Permit Engineer (see below).

Exhibit I

October 2001 – February 2005, **Air Quality Permit Engineer**
New Mexico Environment Department, Air Quality Bureau, Santa Fe, NM

Engineer responsible for evaluating air quality permit applications (including determinations of regulatory applicability, evaluation of regulatory requirements, calculation of air pollution emission rates, and calculation of air pollution control costs) and writing air quality permits to assure compliance of new and existing sources of air pollution with the federal Clean Air Act (including 40 CFR Part 52 - Prevention of Significant Deterioration, 40 CFR Part 70 - Title V Operating Permits, 40 CFR Part 60 - New Source Performance Standards, and 40 CFR Parts 61 and 63 - National Emissions Standards for Hazardous Air Pollutants), as well as the requirements of the New Mexico Air Quality Control Act (including 20.2.72 NMAC - Minor New Source Review and performance standards such as 20.2.14 NMAC – Particulate Emissions from Coal Burning Equipment). Projects while an Air Quality Permit Engineer addressed sources related to coal mining and coal preparation, electric power generation (coal, oil, and gas-fired boilers and combustion turbines), oil and gas exploration and production, natural gas processing and natural gas liquids extraction, natural gas compression and transmission, crude oil refining, hard rock mining construction materials processing (aggregate, hot-mix asphalt, and concrete batching), and semiconductor manufacturing.

September 2000 – September 2001, **Environmental Engineer**
Tetra Tech EMI, Inc. and Harding ESE, Inc., Albuquerque, NM

Environmental scientist/engineer working on air quality permitting and compliance issues and soil contamination sampling (related to a federal Resource Conservation and Recovery Act Phase II facility investigation), and providing technical support for other staff (including computer drafting and data analysis).

September 1995 – June 1998, **National Science Foundation Graduate Trainee in Hydroclimatology**
Program in Atmospheric and Oceanic Sciences, University of Colorado, Boulder, CO

Graduate student work included analysis of field data on arctic clouds and use of a radiative transfer model to evaluate the potential impacts of ice crystal clouds on arctic climatology. Also investigated alternative energy systems, and designed, built, and tested a small prototype vertical axis wind turbine.

July 1990 – August 1990, July 1991 – January 1993, July 1994 – August 1995, **Project Scientist**
Harvard University, Department of Earth and Planetary Sciences, Cambridge, MA

Environmental modeler responsible for developing and validating numerical routines for use in global-scale atmospheric simulations of sources, transport, and deposition of atmospheric trace constituents including sulfur species (DMS, H_2S, SO_2, H_2SO_4), carbon species (CO, CO_2), and hydroxyl radical. One summer as a field engineer working with custom atmospheric sampling equipment at a remote research station at Summit, Greenland.

SPECIAL TRAINING

Fundamentals of New Source Review (AWMA), Advanced New Source Review Workshop (WESTAR), Effective Permit Writing (APTI Course 454), Sources and Control of Volatile Organic Air Pollutants (APTI Course 482), Control of Gaseous Emissions (APTI Course 415), Federal Leak Detection and Repair Programs (US EPA Region 6), Air Inspectors Workshop (US EPA Region 6), Hazardous Waste Operations and Emergency Response (OSHA 40-Hour), Hydrogen Sulfide Hazard Communication and Awareness, Visible Emissions Evaluator (ETA), and Systematic Development of Informed Consent (Institute for Participatory Management and Planning).

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BILL RICHARDSON
Governor

RON CURRY
Secretary

DERRITH WATCHMAN-MOORE
Deputy Secretary

August 29, 2003

CERTIFIED MAIL NO. 7001 2510 0000 8015 4994
RETURN RECEIPT REQUESTED

Mr. Larry Messinger
Mustang Energy Company, L.L.C.
701 Market Street, Suite 953
St. Louis, MO 63101

Permit Application No. 2663
Mustang Generating Station
Revised BACT Analysis

Dear Mr. Messinger:

This letter is in response to the revised best available control technology (BACT) analysis submitted by Mustang Energy Company, L.L.C. (Mustang) for the proposed Mustang Generating Station. The revised BACT analysis, which was received by the New Mexico Environment Department (Department) on June 20, 2003, was required by the Department's letter to Mustang of December 23, 2002. In that letter the Department informed Mustang that the BACT analysis must include an evaluation of integrated gasification combined cycle (IGCC) and circulating fluidized bed (CFB) combustion systems as alternative pollution control options to the proposed pulverized coal (PC) boiler design.

The Department has completed its preliminary review of the revised BACT analysis. As requested, the revised BACT analysis includes an evaluation of IGCC and CFB. The revised BACT analysis also more closely follows the five step "top-down" BACT determination methodology described in Chapter B of the US Environmental Protection Agency 1990 Draft New Source Review Workshop Manual (NSR Manual). Mustang should continue to adhere to this methodology in order to ensure a defensible BACT determination.

Although the revised BACT analysis is an improvement, it remains deficient in certain areas. In order for the Department to continue its review of the BACT analysis, Mustang must correct these deficiencies as outlined below.

1. In Step 1, Mustang includes IGCC and CFB as alternative pollution control options. The Department agrees that IGCC and CFB should be included with other more traditional pollution control approaches. Mustang indicates that the analysis of these control options is

Exhibit II

based on the fuel specified in Mustang's March 5, 2002 application, as amended. The Department also agrees with the fuel choice, but notes that the revised BACT analysis alternatively uses coal with 15.5% and 20 % ash content without explaining the basis for the distinction. Because coal ash content is an important consideration in the design of coal fired units, Mustang must identify and use the correct coal ash content expected at the Mustang site.

2. In Step 2, Mustang concludes that neither IGCC nor CFB are technically feasible control options for the Mustang site. After careful review of the revised BACT analysis, as well as information gathered from independent sources, the Department determines that Mustang's conclusion is not supported by the evidence. Accordingly, the Department finds that Mustang has not demonstrated the technical infeasibility of IGCC and CFB. Moreover, applying the criteria in the NSR Manual, the Department determines that IGCC and CFB are technically feasible at the Mustang site, and must be evaluated in the remaining steps of the top down BACT methodology.

   (a) IGCC and CFB are technically feasible at the Mustang site. A technology is considered to be technically feasible if it is commercially available and applicable to the source under consideration. *See* NSR Manual at B.17-18. A technology is commercially available if it has reached a licensing and commercial sales stage of development. *Id.* A technology is applicable if it has been specified in a permit for the same or a similar source type. *Id.* Mustang's revised BACT analysis indicates that IGCC is commercially available, and IGCC has been specified in air quality permits for coal-fired power plants. *See, e.g.,* Lima Energy Facility, 580 megawatt coal-fired power plant. Similarly, CFB is commercially available and has been specified in air quality permits for coal-fired power plants. *See, e.g.,* AES Puerto Rico 454 megawatt coal-fired power plant; Reliant Energy Seward 584 megawatt coal-fired power plant.

   (b) For both IGCC and CFB, Mustang improperly relies on cost to determine technical infeasibility. A technology is technically feasible when the resolution of technical difficulties is a matter of cost. *See* NSR Manual at B.19-20. Mustang's revised BACT analysis indicates that the resolution of technical difficulties for both IGCC and CFB are a matter of cost. These costs do not support a finding of technical infeasibility, but may be considered during Step 4 of the top down BACT methodology. *See* NSR Manual at B.26.

   (c) For IGCC, Mustang's reliance on historical operating availability, coal quality, and altitude to determine technical infeasibility is not persuasive. With respect to historical operating availability, IGCC can reliably generate 300 megawatts at the Mustang site, although the cost may be higher than at other locations. With respect to coal quality and altitude, fluxing agents such as limestone could be used to compensate for higher ash and fusion temperatures, and the specifications for combustion turbines, including those burning syngas, are adjustable for altitude.

(d) For CFB, Mustang's reliance on coal quality and altitude to determine technical infeasibility is not persuasive. With respect to coal quality, the erosion of surfaces in the back-pass and boiler also would be harmful to a PC boiler, and since Mustang contends that a PC boiler is technically feasible, there is no basis in the revised BACT analysis to reach a different conclusion for CFB. With respect to altitude, CFB has demonstrated excellent levels of performance at lower elevations (e.g., Jacksonville Electric Authority 265 megawatt coal-fired power plant), and can be sized to compensate for Mustang's assumed 25% output loss (e.g., multiple boiler systems at AES Puerto Rico 454 megawatt coal-fired power plant and the Reliant Energy 584 megawatt coal-fired power plant).

To ensure that Mustang's revised analysis contains sufficient information for the Department to continue its review, please be sure to address the following requirements for Steps 3, 4, and 5 of the top down BACT methodology.

3. In Step 3, Mustang ranks the technically feasible control options by average control effectiveness. This step must be amended to include the control effectiveness (including economics) for IGCC and CFB, as well as the other options presented by Mustang. For the purpose of calculating control effectiveness, a baseline emission rate for each pollutant should be calculated based on the emissions typical of an uncontrolled PC boiler firing the coal specified in Mustang's March 5, 2002 application, as amended. Emissions calculated for each control option should be expressed in both pounds per million Btu of coal feed and pounds per megawatt-hour of electricity generated, and emissions reductions should be calculated as the baseline emission rate less the emission rate for the particular control option. Results so derived should be tabulated for each pollutant subject to the analysis. For a control option that controls multiple pollutants, the total control of all pollutants subject to the analysis (e.g., NOx and SO2) also should be summed. The results tabulated in this step must include relevant information developed in Step 4 of the analysis;

4. In Step 4, Mustang must address the energy, economic and environmental impacts of the control options tabulated in Step 3. In order to facilitate comparison between a PC boiler, IGCC, and CFB, the control system battery limits should be the entire generating station project, including all required air pollution controls, and the control option costs should be

measured in terms of total cost of electricity production for the process and control option less the cost of this same production for the typical uncontrolled PC boiler. The cost of electricity production should include annualized capital and operation and maintenance costs, and the average cost effectiveness for each control option should be calculated as the control option cost (in dollars per megawatt-hour of electricity produced) divided by the emission reduction for the control option (in tons per megawatt-hour of electricity produced). For a control option that controls multiple pollutants, the cost effectiveness should be based on the sum of reductions calculated in Step 3, with the costs apportioned to each pollutant according to the relative mass of that pollutant removed. Incremental cost effectiveness also should be calculated if necessary to differentiate between add-on controls. In addition, for each control option, Mustang should evaluate the water use requirements and potential emissions of carbon dioxide (both expressed per megawatt-hour of electricity generated). Mustang should tabulate this information with the average cost effectiveness in Step 3 of the analysis;

5. In Step 5, BACT is selected as the most stringent option tabulated in Step 3 that has not been eliminated after consideration of energy, economic, and environmental impacts. The Department will specify in the permit for the facility both the BACT emission limit and the control technology (proposed by Mustang and approved by the Department after consideration of technical issues and collateral impacts as appropriate) to be used to ensure that the facility will meet the BACT limit.

Please amend the revised analysis as requested and provide the amended material to the Department no later than October 29, 2003. Also, please be advised that the Department is aware of emissions levels expected at several facilities that are lower than those currently specified by Mustang. The Department expects that Mustang will meet or exceed these emissions levels unless a deviation is adequately justified. In particular, the AES Puerto Rico 454 megawatt CFB facility has been permitted at 0.022 lb SO_2 per MMBtu (3-hour basis), 0.10 lb NOx per MMBtu (24-hour basis) and 0.015 lb PM per MMBtu (3-hour basis), while the Wisconsin Electric 615 megawatt IGCC facility has committed to 0.030 lb SO_2 per MMBtu, 0.07 lb NOx per MMBtu, and 0.011 lb PM per MMBtu.

If you have any questions about these requirements please call me in Santa Fe at (505) 955-8041.

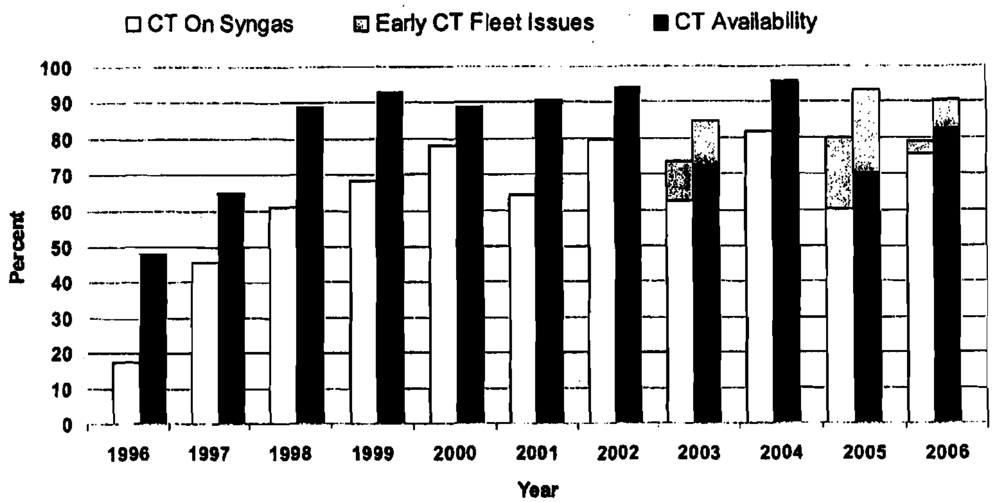
Sincerely,

Mike Fowler

Mike Fowler
Permitting Section
Air Quality Bureau

DOCKET NO. 07_____-EI
POLK UNIT 1 AVAILABILITY
EXHIBIT NO. _______ (MJH-1)
DOCUMENT NO. 2
PAGE 1 OF 1

Polk Unit 1 Availability

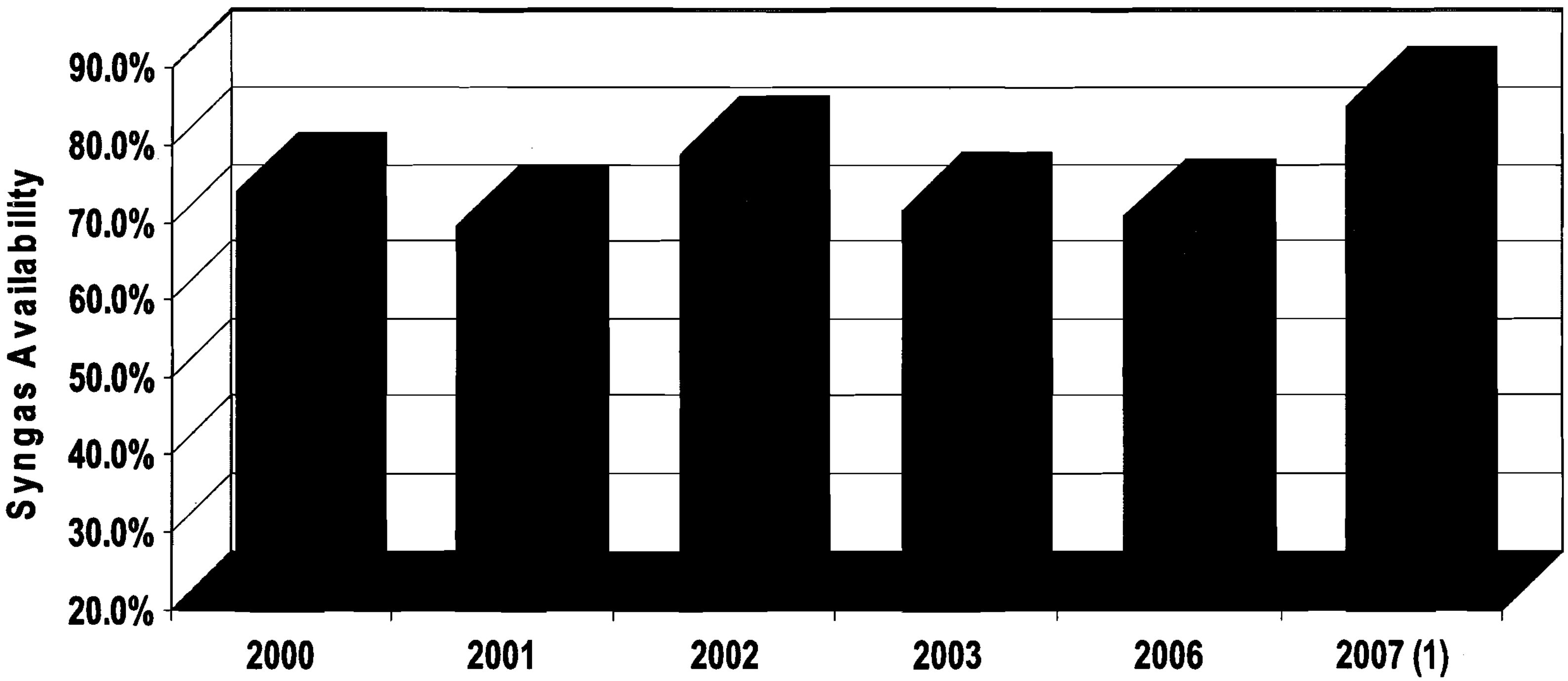


Source: Tampa Electric's Polk Unit 1 performance records

Exhibit III

Maturity of E-Gas Technology at Wabash

Tomorrow...Begins Today



Availability = On Stream % + [Product not Required % * (1-(Forced Outage Rate/100%))]

(1) Through June 8, 2007

Source: SG Solutions, LLC

ConocoPhillips | E-Gas™ Technology for Gasification

Exhibit IV

IGCC Equivalent Working Hours

Target power increased from 520 MW up to 2004 to 528 MW since 2005

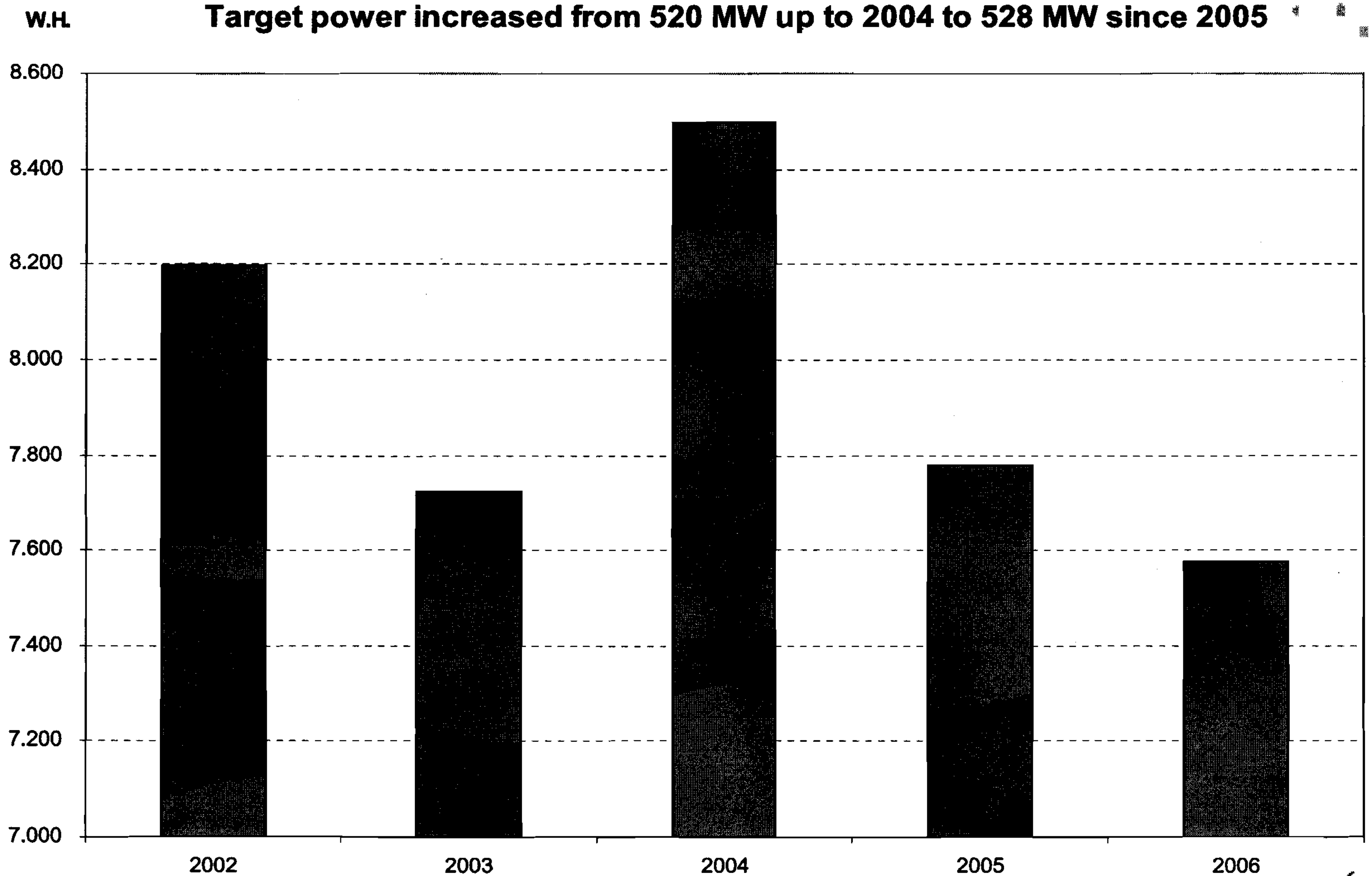
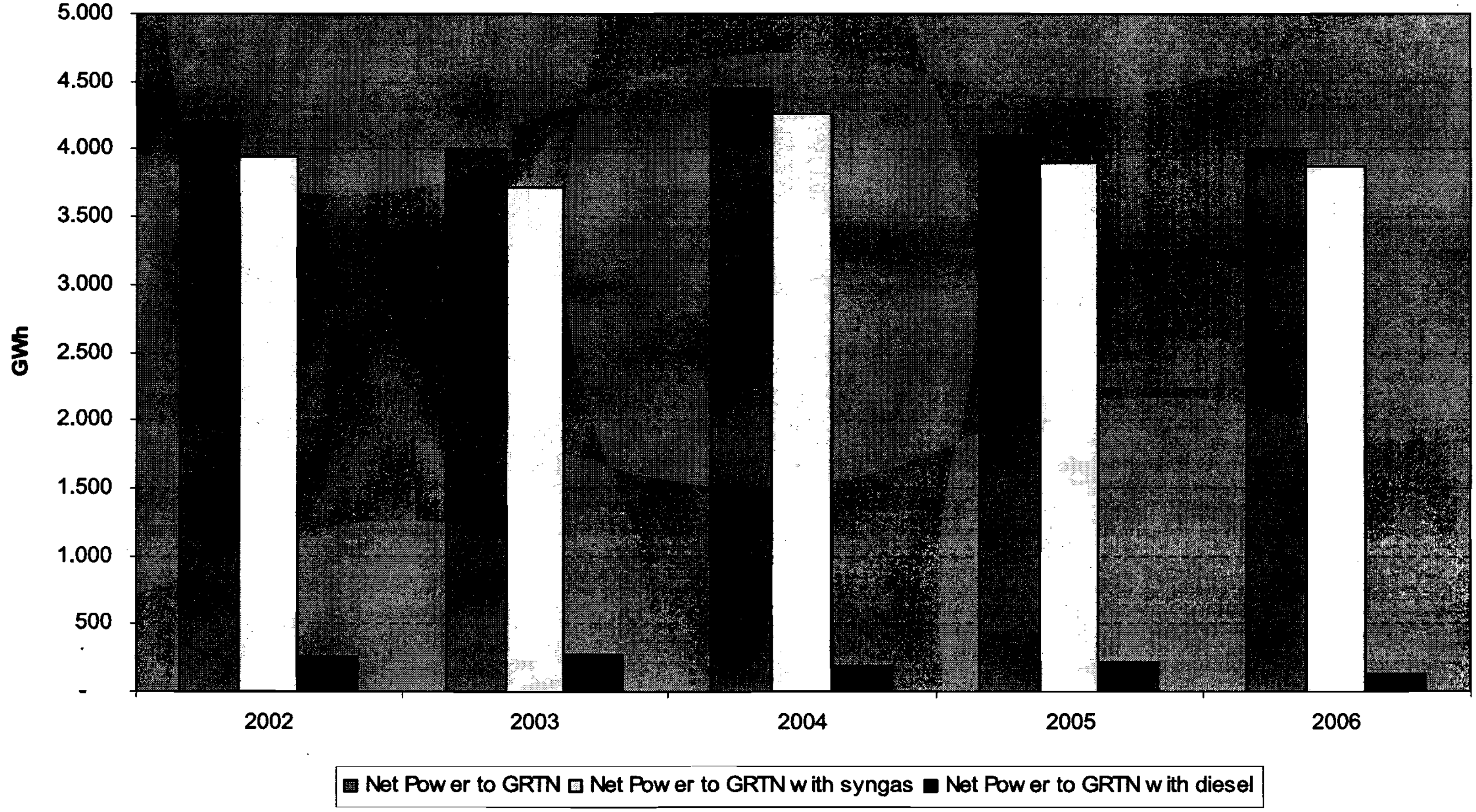


Exhibit V

ERG

International Power
MITSUI & CO., LTD.

Net Power to National Grid



Performance improvement Buggenum

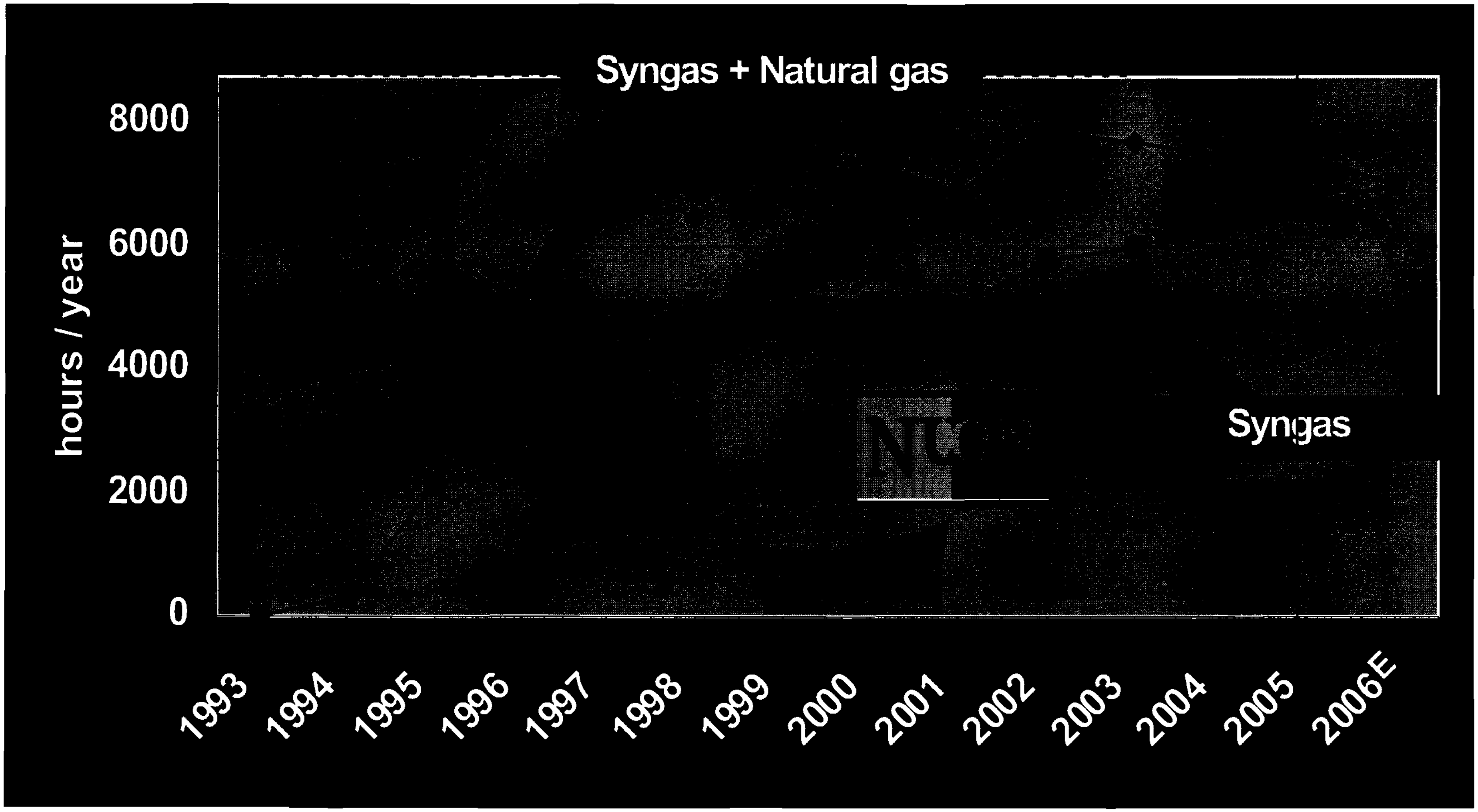


Exhibit VI

CALCULATION OF INCREMENTAL COST EFFECTIVENESS
DRY FORK STATION, GILLETTE, WYOMING
APRIL 29, 2008

ESTIMATED COST AND PERFORMANCE	**PC**	**Source**	**IGCC**	**Source**
Plant Output (MW-net)	368	Basin, p. 15	368	Basin, p. 15
Heat Rate (Btu/kW-hr)	10,077	Basin, p. 15	9,500	See Report
Annual Capacity Factor (decimal)	0.85	See Report	0.85	See Report
Interest Rate (%)	6.00	Basin, p. 16	6.00	Basin, p. 16
Capital Recovery Period (years)	42.00	Basin, p. 16	42.00	Basin, p. 16
Fixed O&M Cost ($/kW-yr)	$24.77	See Report	$26.00	Basin, p. 16
Non Fuel Variable O&M ($/kWh-yr)	$0.0057	See Report	$0.0060	Basin, p. 16
Fuel Cost ($/MMBtu)	$0.57	See Report	$0.57	See Report
Capital Cost (M$)	$1,350.00	Basin, p. 17	$1,755.00	Basin, p. 17
Capital Cost ($/kW)	$3,668.48	Calculated	$4,769.02	Calculated
EMISSIONS	**PC**	**Source**	**IGCC**	**Source**
SO2 (lb/MMBtu coal feed)	0.070	Dry Fork Permit	0.010	See Report
NOx (lb/MMBtu coal feed)	0.050	Dry Fork Permit	0.011	See Report
PM (lb/MMBtu coal feed; filterable only)	0.012	Dry Fork Permit	0.0063	Basin, p. 21
CO (lb/MMBtu coal feed)	0.150	Dry Fork Permit	0.036	Basin, p. 21
VOC (lb/MMBtu coal feed)	0.004	Dry Fork Permit	0.001	Basin, p. 21
CO2 (ton/hour)	379	See Report	357	See Report
COSTS	**PC**	**Source**	**IGCC**	**Difference**
Annual Output (MWh-net/yr)	2,740,128	Calculated	2,740,128	0
Annual Heat Input (MMBtu/yr)	27,612,270	Calculated	26,031,216	-1,581,054
Capital Recovery Factor (%)	6.57	Calculated	6.57	0.00
Annual O&M Total (M$/yr)	24.78	Calculated	26.01	1.23
Annual Debt Service (M$/yr)	88.67	Calculated	115.27	26.60
Annual Fuel Cost (M$/yr)	15.85	Calculated	14.94	-0.91
IGCC SCR Cost (Annualized Capital + O&M) (M$/yr)	-	See Report	5.86	5.86
Total Annual Cost (M$/yr)	129.30	Calculated	162.09	32.78
EMISSIONS	**PC**	**Source**	**IGCC**	**Source**
SO2 (tons/yr)	966	Calculated	130	Calculated
NOx (tons/yr)	690	Calculated	143	Calculated
PM (tons/yr; filterable only)	166	Calculated	82	Calculated
CO (tons/yr)	2,071	Calculated	469	Calculated
VOC (tons/yr)	51	Calculated	13	Calculated
Total (tons/yr)	3,944	Calculated	837	Calculated

INCREMENTAL COST EFFECTIVENESS, PC vs. IGCC	PC Weight Fraction	TAC ($/yr)	Emissions Delta (tons/yr)	Cost Effectiveness ($/ton)
SO2	0.245	8,031,565	836	$9,604.00
NOx	0.175	5,736,832	547	$10,485.22
PM (Filterable) Emissions Delta, tpy	0.042	1,376,840	84	$16,454.56
CO	0.525	17,210,497	1,602	$10,740.73
VOC	0.013	424,526	38	$11,152.04
Total (All of Above)	1.000	$32,780,260.78	3,108	$10,548.73

Exhibit VII