RESPONSE TO STATEMENT OF

STEPHEN D. JENKINS

CH2M HILL, INC.

REGARDING IGCC IN THE BACT ANALYSIS FOR

THE DRY FORK STATION

PREPARED BY

MIKE FOWLER

TECHNOLOGY COORDINATOR, COAL TRANSITION PROJECT

CLEAN AIR TASK FORCE

BOSTON, MASSACHUSETTS

FOR

POWDER RIVER BASIN RESOURCES COUNCIL

SHERIDAN, WYOMING

01 JULY 2008

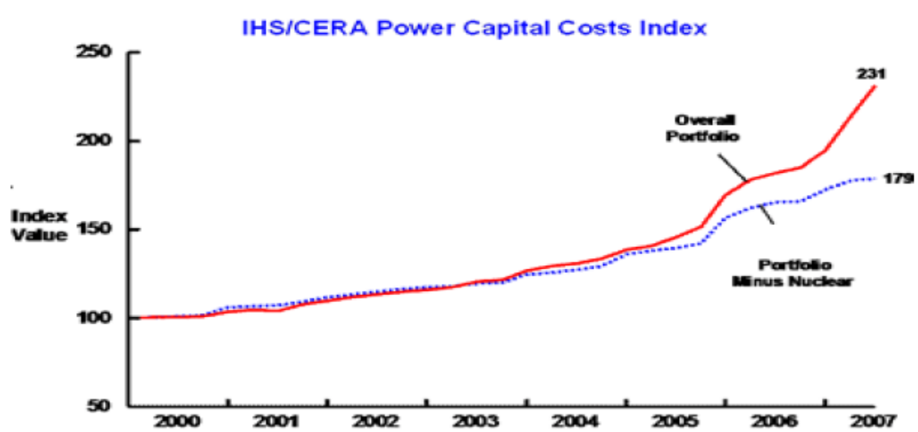
I. INTRODUCTION

In his recent report to the State of Wyoming Environmental Quality Council ("WY EQC") titled "INTEGRATED GASIFICATION COMBINED CYCLE TECHNOLOGY IS NOT COMMERCIALLY AVAILABLE OR TECHNICALLY FEASIBLE FOR MEETING THE REQUIREMENTS OF BASIN ELECTRIC COOPERATIVE'S DRY FORK STATION" (hereinafter the "Jenkins Report"), Mr. Stephen Jenkins of CH2M Hill, Inc. raises a number of issues related to the potential of IGCC technology to provide cost-effective emission reduction for Basin Electric Power Cooperative's ("BEPC") Dry Fork Station and responds at length to a report I submitted to WY DEQ dated April 28, 2008 on behalf of the Powder River Basin Resources Council on that subject (hereinafter "Fowler Report" or simply "my report").

Mr. Jenkins's report contains a number of flawed assumptions and erroneous conclusions about IGCC and the BACT review process. While time does not allow a point-by-point correction of each of the errors in the Jenkins Report, the more significant errors are addressed below. Furthermore, and as a general matter, it should be noted that many of the errors in the Jenkins report appear to stem from his misunderstanding of the appropriate treatment of costs in a BACT analysis, as distinct from commercial availability and technical feasibility. In the final analysis, the most significant issues before WY EQC in this matter are the magnitude of the air pollution to be emitted by the Dry Fork plant and the costs of reducing that pollution.

Unfortunately, costs of all infrastructure projects – including both IGCC and PC power plants - have risen dramatically in the past several years. According to Cambridge Energy Research Associates ("CERA"), for example, the cost of power plant construction rose by some 130% between 2000 and 2007. Figure 1 below, reproduced by CERA's website, shows this trend.

Figure 1 – Cambridge Energy Research Associates Capital Cost Trends[1]



[1] Downloaded from http://energy.ihs.com/News/Press-Releases/2008/North-American-Power-Generation-Construction-Costs-Rise-27-Percent-in-12-Months-to-New-High-IHS-CERA.htm on June 30, 2008.

Recent data suggest an even more extreme trend: since January 1 of this year the price of some steel products has risen 76%.[2] Due to these increases and in order to better assist the Board, I have calculated a new incremental cost-effectiveness for IGCC at Dry Fork, based on revised estimates of capital costs. I have also updated the operation and maintenance costs for the IGCC and PC plants. The new incremental cost-effectiveness estimate is $11,634 per ton of SO2, NOx, PM, CO, and VOC combined. Although this value appears high at first blush, it is worth noting that prior concepts of BACT cost effectiveness have little relevance to determinations made in the current era of high capital costs. Even a wet limestone flue gas desulfurization unit, for example, would cost much more now than several years ago, and agency thinking on appropriate BACT cost levels must be re-evaluated given the recent dramatic cost run-ups.[3]

II. <u>RESPONSE TO SELECTED ERRORS IN THE JENKINS REPORT</u>

Error Number 1 – Contrary to Mr. Jenkins's assertions, evaluation of IGCC is required in the BACT analysis for coal-fueled power plants

Mr. Jenkins states – incorrectly – that "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" (Jenkins Report at p. 9). First and foremost, BACT is defined in the Clean Air Act as an emission limitation, not as a technology choice. Furthermore, Mr. Jenkins interprets BACT far more narrowly than Congress intended. The definition of BACT in the Clean Air Act specifically includes emission reductions achievable for a facility through "application of <u>production processes</u> and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or <u>innovative fuel combustion techniques</u>". (CAA Section 169(3), emphasis added). EPA's 1990 Draft New Source Review Workshop Manual ("NSRM") provides guidance for evaluation of lower-emitting production processes in BACT, and states that "a production process is defined in terms of its physical and chemical unit operations used to produce the desired product from a specified set of raw materials" (NSRM at B.13-B.14). These issues are discussed in detail in my earlier report. In the case of the Dry Fork power plant the specified raw material – which my report did not challenge – is sub-bituminous coal from the Power River Basin in Wyoming. The desired product, clearly, is electricity.

Both IGCC and PC power plants are regulated under the Clean Air Act as electric utility steam generating units and fossil fuel fired steam electric plants. Recognizing this, and affirming that IGCC is an "innovative fuel combustion technique" only yesterday a court in Georgia remanded an air quality permit for a coal power plant because the permit applicant and reviewing

---

[2] Dale Crofts, Bloomberg News, May 30, 2008.

[3] Recent media reports from Wisconsin suggest that the cost of flue gas desulfurization equipment have almost doubled in the past few years. See Exhibit IV.

agency had failed to consider IGCC in the BACT analysis.[4]

Error Number 2 – Contrary to Mr. Jenkins's assertions, liquid-feed IGCC are comparable with coal-feed IGCC in many respects

Mr. Jenkins states in his report that "it is inappropriate to compare liquid feedstock-based IGCC plants to coal-based IGCC plants" (Jenkins Report, p. 31) and that liquid-feed IGCC have as their "primary purpose" the "production of hydrogen and/or steam for the adjacent refineries, not the production of electricity" (Jenkins Report at p. 32). Mr. Jenkins is incorrect on both counts. The 528 MW dual-train ISAB IGCC in Italy, for example, was developed explicitly to convert refinery waste into electric power for sale to the national grid. The 540 MW Sarlux IGCC, also in Italy, was developed for similar purposes (although that IGCC also produces hydrogen for use in the adjacent refinery).

Regarding the technical differences between liquid-feed IGCC and coal-feed IGCC, I agree with Mr. Jenkins that there are some differences in the feed handling equipment, gasifier, slag handling, and syngas scrubbing and filtering. These differences represent but a fraction of an entire IGCC plant, however. Many plant components in coal-feed and liquid-feed IGCC are quite similar, including the air separation unit ("ASU"), the acid gas removal ("AGR") equipment, the sulfur recovery unit ("SRU"), the combustion turbine ("CT"), the heat recovery steam generator ("HRSG), the steam turbine ("ST") and air pollution control equipment such as selective catalytic reduction ("SCR") units. This is because downstream of the gasifier and first steps of syngas cleanup (removal of solid particles) the feed has been fully converted into a gaseous form that is similar, although not identical, for liquid-feed and coal-feed systems.

Figure 2, contained in Exhibit V, is a block flow diagram for a generic 500 MW IGCC power plant. If such a plant were operated on liquid feed instead of coal the gasifier and syngas scrubber block would change somewhat, but conceptually the rest of the plant would be largely the same. The relative size and detailed configuration of the various pieces of equipment would change, however, depending on the design feedstock.

The comparison and similarities between liquid-feed and coal-feed IGCC is especially relevant considering that most of the world's experience with coal-based gasification is not in a power generation (e.g., IGCC) setting. Experience with gasifying coal for non-power generation purposes, combined with experience operating IGCC on liquid-feed, therefore is clearly relevant to the applicability of IGCC to the Dry Fork Station.

Error Number 3 – Contrary to Mr. Jenkins's assertions, many existing IGCC are "successful"

Mr. Jenkins states – incorrectly – that IGCC "has only been demonstrated at small scale,

[4] See Final Order, Friends of the Chattahoochee, Inc. v. Georgia DNR, No. 2008CV146398 (Super. Court, Fulton County, GA, June 30, 2008).

as noted above, and even those demonstrations cannot be considered to be successful since the plants have not met their design goals" (Jenkins Report at p.13). Mr. Jenkins's comments in this regard are at odds with public statements he has made in the past and are at odds with public statements by IGCC developers including American Electric Power Company ("AEP"). In addition, Mr. Jenkins is in error on this point because several of the existing coal-feed IGCC plants are clearly "successful" and several existing liquid-feed IGCC have performed extremely well (as I indicated in my earlier report).

According to testimony provided to the West Virginia Public Service Commission by AEP subsidiary Appalachian Power Company ("APCo") "The processes used in APCo's proposed IGCC facility have been commercially proven through their use in IGCC plants and in the chemical and energy industries. The plant design is an evolution of TECO's Polk Plant design incorporating all the innovations and design changes developed during its 10 year operating history." Furthermore:

> Today, Polk operates with acceptably high availability and reliability. The APCo plant design is based largely on the current Polk plant design. In addition to employing design changes made at the Polk Plant, the APCo plant design employs additional improvements that have not been able to be installed on a retrofit basis at Polk. For example, a major source of outage at the Polk Plant is caused by pluggage of the convective syngas coolers. These coolers have been eliminated in the APCo plant design. GE has worked closely with Polk and other IGCC plants to develop and test design improvements and to validate design models. APCo's IGCC plant availability and reliability will have the benefit of this development work and therefore will present an improvement over the current operating facilities.[5]

In 2005, while employed by URS Corporation, Mr. Jenkins prepared a presentation on the Tampa Electric Company experience with the Polk IGCC in which he stated:

- During start-up - "challenges and problems not too different from coal-fired units or gas-fired combined cycle units";
- In year 1 of operation - "many little things contributed to lower than expected availability, but problems were not attributable to the basic IGCC technology";
- In year 3 of operation - "lowest generation cost in Tampa Electric fleet – first unit dispatched";
- In year 7 - "commitment to coal shows IGCC to be a smart choice";

[5] See DIRECT TESTIMONY OF DR. PAUL CHODAK ON BEHALF OF APPALACHIAN POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA IN CASE NO. 06-0033-E-CN, June 18, 2007, pages 4 – 5.

- In year 8 of operation - "82% on-stream factor for gasification", "96% availability for power block", "99%+ availability on-peak".[6]

Mr. Jenkins's comments from 2005 and the comments of AEP on the success of previous IGCC demonstrations are at odds with the statements of Mr. Jenkins in the report prepared for BEPC. Furthermore, and as discussed in more detail below, IGCC has achieved high availability in a number of instances.

Error Number 4 – Contrary to Mr. Jenkins's assertions, IGCC is commercially available for the Dry Fork Station

Mr. Jenkins states that "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" (Jenkins Report at p. 27). This is incorrect. In fact, several major IGCC technology providers and allied engineer-procure-construct ("EPC") firms have indicated a willingness to offer commercial IGCC for plant sites at high elevation, on sub-bituminous coal, and for plant capacities less than the standard dual-train configurations. In 2005, for example, ConocoPhillips (at that time in alliance with Fluor) indicated to Peabody Energy that they would be willing to provide "operating and maintenance services in addition to turnkey design and construction" for a 300 MW IGCC to be operated with high ash, high moisture sub-bituminous coal in New Mexico. A copy of ConocoPhillips' letter to Peabody is attached as Exhibit I.

In 2007, PacifiCorp issued a request for proposals ("RFP") for a Wyoming IGCC at 6,620 feet elevation, using low-heating value PRB coal. Shell/Black & Veach, General Electric, Siemens, and ConocoPhillips/WorleyParsosns responded to the RFP. Although the General Electric response did not conform to the RFP, blinded results for the other three technologies are publically available and indicate that each of these vendors offer a commercial IGCC for high elevation on PRB sub-bituminous coal. Net capacity of the three proposed IGCC plants, including CO2 removal in excess of 66%, are 483 MW, 529 MW, and 409 MW. Responses from the vendors also indicate that availability of their plants on syngas would be 84.4%, 79.3%, and 84.6%. Exhibit II is a copy of a presentation by PacifiCorp on their Wyoming IGCC RFP.

ConocoPhillips, Shell, and Siemens technology are all commercially available for deployment an IGCC at high elevation, operating on PRB sub-bituminous coal, at 385 MW net capacity, and EPC firms are available who will design and build the plant and provide assurances of performance in alliance with the technology vendors. Mitsubishi Heavy Industries has also developed a commercial IGCC offering. As PacifiCorp noted in their presentation, however, the IGCC "market [is] <u>reluctant</u> to provide "full-wrap" lump sum turn key pricing" (emphasis

[6] See "Real World Experience with IGCC – Lessons Learned in Design, Permitting, Operations, and Maintenance", presentation by Steve Jenkins, URS Corporation, August 17, 2005, available at www.energy.ca.gov.

added).[7] While the IGCC marketers may be reluctant to provide "full wrap" lump sum turn key pricing, due to recent cost escalation the same likely could be said of vendors of PC technology. In fact, Mr. Jenkins provides no basis in his report for a conclusion that the PC plant proposed by BEPC for Dry Fork is commercially available under contract terms significantly different from those available for IGCC. In the end, the real difference between the commercial offerings for IGCC and PC is cost.

Error Number 5 – Contrary to Mr. Jenkins's assertions, IGCC can provide adequate availability for the Dry Fork Station

Mr. Jenkins suggests that an overall plant availability factor of 95% should be considered part of the basic design of the Dry Fork Station for the purposes of the plant's BACT analysis. Mr. Jenkins further discounts availability of IGCC plants when operating on back-up fuel, asserting without support that "the availability of the complete IGCC plant is what must be considered and compared" (Jenkins Report at p. 38). I disagree with Mr. Jenkins on both of these points. In fact, for all reasonable cases, plant availability factor is an economic criterion in the BACT analysis that should not be included in determinations of commercial availability and technical feasibility. Furthermore, IGCC operation on back-up fuel provides real, bankable availability which can be an economic enhancement for an IGCC plant.

The availability factor for a power plant is a measure of the fraction of time each year during which the plant is available to produce electricity for sale. An availability factor of 90%, for example, indicates that a power plant is available to produce meaningful amounts of power for 90% of the year, including both scheduled outages and forced outages. According to data developed by the North American Electric Reliability Council in the 2005 Generation Availability Report and reported by the Electric Power Research Institute ("EPRI"), during the period from 2000 to 2004 US coal-fired power plants had an average equivalent availability factor of 84.9%.[8] An availability factor of 85% therefore represents a reasonable criteria in the BACT analysis for Dry Fork.

The results of the PacifiCorp RFP indicate that availability of approximately 85% on syngas is achievable for the particular case of an IGCC operating at high elevation on PRB sub-bituminous coal (at least for two of the three listed technologies). In addition, as Mr. Jenkins's own previous work indicates, availability on back-up fuel for a coal-based IGCC power block has been as high as 96%, with on-peak availability of 99%.

Error Number 6 – Contrary to Mr. Jenkins's assertions, IGCC is applicable to the Dry Fork Station

Mr. Jenkins states – incorrectly – that IGCC is not "technically feasible" for the Dry Fork

[7] See Exhibit II, PacifiCorp presentation on the Jim Bridger RFP.
[8] Evaluation of Alternative IGCC Plant Designs for High Availability and Near Zero Emissions, RAM Analysis and Impact of SCR, EPRI, 2005, p. 2-4.

plant because, in addition to being unavailable commercially, IGCC is not applicable to a high elevation site. Mr. Jenkins fails to recognize, however, that the effects of elevation on IGCC are issues of cost and are not, under the framework of the NSRM, issues of technical feasibility. As I stated in my report – correctly – an IGCC operating at high elevation would have reduced output compared to the same IGCC at sea level, due to the effect of reduced air density on the combustion turbine and power block. Similarly, the air separation unit for an IGCC operating at high elevation must be larger, relative to the quantity of oxygen produced, than an ASU at sea level. Overall, the net effect would be approximately 13% less output at 4,000 feet elevation, as Mr. Jenkins states.[9] This does not effect the technical ability of the IGCC to generate electricity, however. Rather, it effects the specific cost ($/kW) of the IGCC plant compared to a plant at sea level. Nothing about the Dry Fork site elevation makes IGCC inoperable there.

Error Number 7 – Contrary to Mr. Jenkins's assertions, my calculation of emissions rates for the Taylorville, Edwardsport, and Mountaineer IGCCs was not flawed

Mr. Jenkins states – incorrectly – that I miscalculated the SO2 emission rates for the Taylorville, Edwardsport and Mountaineer IGCC, and that I miscalculated the NOx emission rate for the Edwardsport IGCC, and that as a result portions of my report rest on "a false comparison" (Jenkins Report at p. 35). Mr. Jenkins also states that such an error is "frequently made by many that attempt to compare emission rates of different IGCC and PC plants", and that "those with experience in the permitting and design of IGCC plants understand this difference and note the basis of the emission rates when referencing them" (Jenkins Report at p. 35).

Contrary to Mr. Jenkins's assertions, however, I calculated the emissions levels noted above correctly, but using a deliberately conservative approach intended to allow an equitable comparison between air quality permit emission limitations for IGCC and PC technology. For reference, the table that appeared in my earlier report is reproduced below as Table 1.

Table 1 – 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

[9] See "CO2 Capture: Impacts on IGCC Plant Performance in a High Elevation Application using Western Sub-Bituminous Coal", presentation by ConocoPhillips and WorleyParsons to Gasification Technologies Conference, San Francisco, 2007, and "Gasification at Elevation: ASU Design Impact:", presentation of Air Liquide to Workshop on Gasification Technologies, Denver, 2007

Plant Name and Data Source		Emissions[a,b] (in lb/MMBtu coal feed)				
Plant	**Source**	**SO2**	**NOx**	**PM[c]**	**CO**	**VOC**
EPA IGCC[10]	Study	0.012	0.044	0.007 (f)	0.03	0.002

Notes to Table 1: 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.

Mr. Jenkins suggests that I miscalculated the SO2 emissions for the Taylorville, Edwardsport, and Mountaineer IGCC, and that I miscalculated the NOx emissions for the Edwardsport IGCC, by basing my calculation on heat input rate to the combustion turbines rather than total coal input to the facility. Mr. Jenkins is incorrect. In fact, in order to provide a fair basis for comparison between IGCC and PC plants, in my calculation I used the total coal input to the facility, and included SO2 emissions from the oxidation of SRU tail gas at the Taylorville, Edwardsport, and Mountineer IGCCs as allowed by air quality permits for the facilities or (in the case of Mountaineer) as requested in the air quality permit application. Using the Taylorville plant as an example, permitted SO2 emissions from the combustion turbines are 299.2 tons per year and permitted SO2 emissions from the thermal oxidizer are 91.2 tons per year, both based on 8760 hours per year of operation.[11] This equates to 89.13 pounds of SO2 emitted per hour, and, given the plant's nominal heat input rate (as coal) of 5,835 MMBtu per hour, an emission rate of 89.13 divided by 5,835, or 0.015 lb/MMBtu coal feed.

While these emissions are requested and/or permitted for these facilities, it is not clear that emissions of SO2 from sources other than the combustion turbine stacks will in fact be significant during normal operation. Tail gas from the SRUs in fact may be recycled to the process. In order to provide a fair basis for comparison, however, I included the emissions in my report. It should be noted that had I not included these emissions the environmental performance of the IGCC plants would have appeared even more advantageous in my table.

As a final point on this subject, Mr. Jenkins also incorrectly assumed – without basis – that I miscalculated the NOx emissions from the Edwardsport IGCC in my report. In fact, the air quality permit for the Edwardsport IGCC appears to include only a NOx limit for the entire facility of 2122 tons per year, which equates to approximately 0.083 lb/MMBtu of coal input.

[10] See "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies", EPA, July, 2006.
[11] See Table III of Attachment I to Illinois EPA Air Quality Permit I.D. Number 021060ACB, issued to Christian County Generation, LLC on June 5, 2007.

Error Number 8 – Contrary to Mr. Jenkins's assertions, SCR is technically feasible for coal-feed IGCC

Mr. Jenkins states – incorrectly – that "SCR is not technically feasible at this time for application to IGCC technology" (Jenkins Report at p. 47). As support for this contention Mr. Jenkins notes industry concern about SCR leading to formation of sticky salt deposits in downstream equipment that must be cleaned regularly. Mr. Jenkins's comment ignores the fact that SCR is already in use on number of IGCC around the world, however (including the ISAB and api Energia IGCC in Italy and the Negishi IGCC in Japan), and that SCR has been proposed and/or permitted for several IGCC in the US (including the Taylorville and Edwardsport IGCCs). SCR is also routinely used on natural gas-fired combined cycle combustion turbines ("NGCC").

The primary technical issue related to use of SCR on IGCC plants is formation of ammonium bisulfate salts in the plant HRSG as SO3 in the combustion turbine exhaust – formed in small quantities during combustion of syngas in the turbine – reacts with ammonia added to the SCR system to reduce NOx emissions. This issue is essentially unrelated to IGCC plant feedstock, since the sulfur content of the syngas presented to the turbine depends primarily on the nature of the acid gas removal system. There is very little experience actually operating an SCR on coal-based IGCC, however, and therefore some plant developers have elected to install SCR outside the scope of air quality permit requirements (e.g., the Edwardsport IGCC) or have proposed to include SCR at a relatively low control efficiency (e.g., Tampa Electric Company's recent IGCC proposal, which has since been shelved).

Error Number 9 – Contrary to Mr. Jenkins's assertions, the incremental cost effectiveness of IGCC at Dry Fork, compared to PC, would be <u>significantly</u> less than $26,400 per ton

Mr. Jenkins states – incorrectly – that the cost effectiveness of IGCC at Dry Fork, compared to PC, would be $26,400 per ton for control of SO2, NOx, PM, CO, and VOC combined. Mr. Jenkins's analysis is based on escalated capital costs for his hypothetical IGCC plant and un-escalated capital costs for his hypothetical PC plant, even though those costs have also increased dramatically. In addition, his analysis assumes more than $14 million dollars per year in extra fuel costs for the IGCC plant, and he has not considered the air pollution control benefits of SCR in his calculation.

In Exhibit III I have updated the cost effectiveness calculation I provided in my report dated April 28, 2008. In particular:

- I have increased the capital cost of both the PC and IGCC plants by an additional 10%. This increase brings the capital cost of the PC plant to just over $4,000/kW, in keeping with recent reports of the capital cost a similar-sized PC plant proposed by Alliant Energy in Wisconsin. Exhibit IV is a recent media report on the cost increases for the Alliant plant. It should be noted, however, that the actual price level for current projects is difficult to predict accurately in advance. In fact, a number of EPC firms, technology vendors, and plant developers have informed me that material suppliers are currently unwilling to quote prices more than several days or weeks in advance.

- I have also increased the PC and IGCC plant operation and maintenance costs by an additional 10%.

Based on these values, I calculate a new incremental cost-effectiveness for SO2, NOx, PM, CO, and VOC (combined) for Dry Fork of $11,634/ton. As noted above, however, there are currently large difficulties in accurately projecting costs for power plant projects.

III. SUMMARY

Consideration of IGCC is required in the BACT analysis for new coal-fueled power plants. Such consideration indicates that IGCC is a commercially available and technically feasible emission reduction option for the Dry Fork Station (385 MW net capacity, high elevation, operating on sub-bituminous coal from the Power River Basin). A preliminary analysis indicates that at the Dry Fork site, IGCC would emit more than 3,000 tons per year less air pollution (SO2, NOx, PM, CO, and VOC only) compared to the PC plant currently proposed by BEPC, but could cost approximately 38 million dollars per year more to operate. The incremental cost-effectiveness of that air pollution reduction therefore is $11,634/ton. This is within the range of BACT cost effectiveness values that are reasonable for Dry Fork.

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

July 1, 2008

Date

EXHIBIT 1

ConocoPhillips

July 1, 2005

Peabody Energy
701 Market Street
St. Louis, Missouri 63101-1826

Attention: Mr. Rick Bowen
Senior Vice President & President Generation

Subject: Mustang Project
300 MW Coal Fired Facility in McKinley County, New Mexico

Thank you for your interest in the E-Gas Technology for Coal Gasification. The E-Gas Technology has been utilized to produce power from sub-bituminous and bituminous coals and petroleum coke in commercial scale facilities over the last 18 years, and has done so with unequalled environmental performance..

We have received your June 9 letter and a subsequent "worst case analysis" for the El Segundo coal. However, the information provided by Peabody for the Mustang project basis in these documents is insufficient to answer many of the technical questions posed in your June 9, 2005 letter. Other questions involve proprietary or commercially sensitive information to which we cannot respond without suitable nondisclosure agreements.

Typically the E-Gas Alliance (ConocoPhillips and Fluor) provide detailed site specific and fuel specific analyses under contract for a scoping study where detailed information is exchanged under confidentiality agreements to provide a design that is tailored to the customers goals for the facility. Based on the results of this initial feasibility and project definition analysis, project sponsors make decisions on whether to proceed with Front End Engineering Design, which includes the development of cost and performance targets and EPC term sheets. This is not a three week effort.

The responses provided below are based upon information previously made public or previously supplied to Peabody without confidentiality agreements.

Q1: Based on the project information provided, can the ConocoPhillips process utilize the proposed fuel and site? If so could you provide references where a similar fuel has been utilized and projects completed at elevation greater than 5,000 ft AMSL. Please include information regarding how long the facility has been operating, performance and availability information (examples heat rate, degradation curves, monthly & annual availability). How much coal would be required on an annual basis at 100% rated output?

A1: The 16% moisture, 20% ash El Segundo coal can be gasified in the E-Gas Process. E-Gas has utilized both high moisture and high ash fuels previously, though not in this combination.

I am unaware of any gasification facilities operating at 5000 foot plus elevations. The

E-Gas Technology
Peabody Mustang Project

July 1, 2005

Great Plains Gasification Facility is at an elevation of about 4000 feet as I recall. Elevation does not represent a technical challenge for gasification, the gasifier and directly associated processes are operating at not particularly sensitive to either elevation or ambient temperature. These factors do greatly impact the operation of the combined cycle facility, as you know, and this presents economic challenges for any combustion turbine based facility.

A conceptual E-Gas analysis was made several years back, at Peabody's request, of an IGCC facility at approximately 7000 feet elevation that would utilize coal from your South Hospah mine (16% ash and 16% moisture). Based on two 7FA combustion turbines, the facility was estimated to have a net output of 420 MW and a heat rate of about 9500 Btu/kWh. This performance would be improved with the General Electric and Siemens machines now being offered commercially.

Q2: Can you provide an indicative cost estimate for the facility (EPC basis)? · It is expected that the facility will be project financed with third party off balance sheet debt.

A2: The previous South Hospah analysis indicated an overnight Bare EPC cost (2001$ without contractor profit or contingency or significant risk premiums) at about $1450/kW. (The higher elevation decreased output and inflated the capital cost on a unit output, electrical generation basis.) The cost for the Mustang plant, with increases in steel prices – especially those in late 2004 - and with none of the economies of scale for a larger facility because of the 300 MW transmission limitation, may approach $2000/kW.

Q3: Would ConocoPhillips (or ConocoPhillips in a partnership or consortium with others) be prepared to provide a "full wrap" of the project with respect to schedule/completion, environmental, output, performance and availability guarantees, any others? What cap limits (either in % or absolute dollar value) would you be willing to accept for the guarantees? Please describe how the values would be calculated.

A4: ConocoPhillips and Fluor announced an alliance for gasification projects on May 24, 2004, with the goal of providing a "full wrap" gasification project product to power and industrial gasification markets worldwide. The press release is attached.

I will have to decline to discuss the commercial details of the Alliance offering in this letter. Note however, that the Alliance can provide operations and maintenance services in addition to turnkey design and construction.

Q4: Would ConocoPhillips be willing to consider equity ownership, financing, or any other financial options for a plant of this type?

A4: While ConocoPhillips is currently evaluating equity participation in certain gasification facilities, this evaluation is always project-specific. Again, we must decline to discuss the specifics at this stage.

Q5: What site requirements would be necessary such as how many acres, quantity of water, any start-up fuel requirements such as natural gas, and other requirements?

E-Gas Technology
Peabody Mustang Project

July 1, 2005

The Wabash River facility, a 262 MW repowering of an existing conventional pulverized coal plant, sits on a site of about 20 acres (exclusive of the steam turbine facilities but including the coal pile and the new equipment). Excluding cooling tower losses and steam injection for NOx control, that facility consumes about 500 gpm. The wastewater stream from the gasification island is about 150 gpm and is treated in an evaporator system to make the gasification island zero liquid discharge. Natural gas, propane or fuel oil can be used for start-up.

Q6: What emission limits would ConocoPhillips be willing to guarantee (in lbs/MMBtu based on 3 hr, 24 hr, and 30 day rolling average) for SO2, NOx, CO, VOC, PM10 filterable and condensable, mercury, HCl, HF, lead, and beryllium? These amounts would need to include emissions from any vents, flares, or stacks. If emissions are not controlled to the same levels during startup, shutdown, or reduced load operation please provide tables indicating emissions and duration during these processes.

A6: This level of detailed information could be generated in a scoping study. Generally though, the IGCC emissions for a facility with a Selexol acid gas removal system and SCR would produce Sox emissions of less than 0.03 lb/MMBtu, NOx emissions below 5 ppm, nearly undetectable particulate emissions and would achieve 90-95% mercury removal. Emissions during transient operation are similar, the E-Gas process design does not vent or flare untreated syngas during start-up or shutdown.

Q7: What quantities of waste would be generated by the facility and what type of disposal would be required? Any hazardous waste generated?

A7: There are no solid wastes from operation of the standard configuration of the E-Gas Process. There are two normally saleable byproducts, sulfur and slag. Sulfur is produced as solid elemental sulfur that exceeds commercial grade A and is salable into the fertilizer market. The ash content of the coal is reduced to an inert, non-leaching slag that has been utilized in asphalt production and as a construction material.

In a facility designed for zero liquid discharge, trace metals from the coal are captured in a salt produced by evaporation of the wastewater stream. This material, nominally a few drums per week, may be classified as a hazardous material depending on the trace elements in the coal. This is, of course, a better outcome than emitting these materials into the air or water at the site.

The carbon beds used to remove mercury from the syngas (over 90% removal is expected) will be changed periodically (2-3 years), and this material is also typically classified as a hazardous waste.

Q8: Would you be able to provide estimates of operating costs and numbers of employees required for this type of facility?

A8: This information is part of the scoping package. The E-Gas Team is the only technology supplier that has operated its gasifier on solid fuels. The Alliance is willing to accept operating and maintenance responsibilities on a short or long-term basis.

Q9: What length of time would be required for start-up of the facility -cold start, hot start, etc and what would be the load profile - what is the minimum load at which the facility can operate and what heat rate impacts might be expected? Would the facility be capable of load following?

A9: This information is part of the scoping package. While gasification facilities, like any large chemical plant, operate best at a stable operating level, it can be cycle to a limited extent. Minimum load for such operation depends on project configuration, but the general expectation is that 50% turndown is achievable.

Q10: Many vendors of IGCC technology are advertising carbon sequestration ready. If your technology is capable of carbon capture, please describe the process and equipment required as well as any additional costs for this feature, assuming a 50% hydrogen fuel to the gas turbine.

A10: Carbon capture from an IGCC facility is accomplished utilizing commercial technologies. The gasification process produces a syngas stream that is primarily CO and H2. Typically a shift process would be utilized to increase the hydrogen content, an acid gas removal system such as Selexol with pressure swing absorption would be used to remove sulfur and produce a CO2 stream. We have not looked at the incremental capital cost to produce a 50% hydrogen fuel, but have studies indicating that 90% carbon removal configurations, inclusive of the Selexol system, SCR on the combustion turbine exhaust and carbon separation (but not compression and storage) will add over $200/kW to the installed cost of the facility.

Q11: Could you meet a 2010 start-up schedule if construction began in mid 2006? How long would it take the facility to reach commercial status after first start?

A11: With a full release to begin equipment procurement in mid-2006, start-up in 2010 is achievable. Actual in-field construction time would be less than two years. From first fire of the gasifier, the unit should be operating at rated availabilities within one year.

The ConocoPhillips-Fluor E-Gas Alliance team looks forward to additional discussions with Peabody Energy. Please do not hesitate to contact me (Phil.Amick@conocophillips.com, 281.293.2724) for additional discussion.

Best Regards,

Phil Amick

Phil Amick
Technology Director, Gasification

CC: Lars Scott

ConocoPhillips

600 North Dairy Ashford
(77079-1175)
P. O. Box 2197
Houston, TX 77252-2197
Phone 281.293.1000
www.conocophillips.com

NEWS RELEASE

ConocoPhillips and Fluor Announce Gasification Technology Alliance

HOUSTON, May 24, 2004 --- ConocoPhillips (NYSE:COP) and Fluor Corporation (NYSE:FLR) today announced the signing of a worldwide alliance agreement to facilitate the development, design and construction of new projects utilizing ConocoPhillips' E-Gas Technology. Under the agreement, 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. The terms of the agreement were not disclosed.

The E-GAS Technology incorporates a unique, proprietary gasification system design which can be applied with gas turbine and steam power generation in an advanced Integrated Gasification Combined Cycle configuration to produce electric power, as well as co-producing synthesis gas, hydrogen and steam in highly flexible combinations. It is among the cleanest, most efficient commercial technologies for coal- or petroleum coke-based electric power generation, offering high-system efficiencies, lower costs and very low emissions, when compared with conventional pulverized coal-based power generation. Gasification also can provide a low-cost alternative to natural gas reforming to create synthesis gas for refinery hydrogen, synthetic liquid fuels and chemicals production.

Through the alliance, ConocoPhillips and Fluor have combined to provide E-Gas Technology customers both project development support for planned projects, conceptual and detailed engineering and turnkey contracts for construction of solid fuel gasification facilities.

"The alliance with Fluor is our first step in building a powerful team to promote the use of the E-Gas Technology," said Brian Evans, manager, ConocoPhillips Technology Solutions. "ConocoPhillips' extensive experience in gasification and in technology licensing, combined with Fluor's leadership in the project development, financing, engineering and construction of both process plants and combined cycle facilities, makes this a natural combination to supply the environmental and efficiency benefits of gasification to the refining, power generation and chemical industries."

E-Gas Technology
Peabody Mustang Project

July 1, 2005

E-GAS Technology converts coal and other low-grade feedstocks, including petroleum coke, which may have a negative economic value, into a clean synthesis gas containing hydrogen. The process allows virtually all pollutant-forming impurities to be removed, including mercury from coal, and is readily adaptable for further removal of carbon in the future. Carbon dioxide is suspected to be a leading agent in global warming.

"Fluor is pleased to join with ConocoPhillips to provide our customers with advanced technology solutions for converting solid fuels to clean and cost-effective energy and chemical products based on the E-Gas Technology," said Jeff Faulk, president of Fluor's Oil, Gas & Power group.

The Wabash River Coal Gasification Repowering Project, in West Terre Haute, Indiana, has been demonstrating the technology on a commercial basis since 1995. A leader in the U.S. Department of Energy's "Clean Coal Technology Program," the Wabash River Plant has gasified over three million tons of coal and petroleum coke over the past eight years and can operate interchangeably on either fuel.

Fluor and ConocoPhillips are also preparing a structure to provide operating and maintenance agreements for gasification facilities utilizing the E-Gas Technology, drawing from the extensive collective experience of the two companies.

Fluor Corporation (NYSE:FLR) provides services on a global basis in the fields of engineering, procurement, construction, operations, maintenance and project management. Headquartered in Aliso Viejo, Calif., Fluor is a FORTUNE 500 company with revenues of nearly $9 billion in 2003. For more information, visit www.fluor.com.

The Technology Solutions Division of ConocoPhillips licenses several world-class technologies in addition to E-Gas: including ThruPlus Delayed Coking, ReVap Alkylation, and S Zorb Desulfurization Technology for gasoline. More information on these technologies can be found at www.coptechnologysolutions.com.

ConocoPhillips is an integrated oil company with interests around the world. Headquartered in Houston, the company had approximately 37,200 employees and $84 billion of assets as of March 31, 2004. For more information, go to www.conocophillips.com

- # # # -

CONTACTS:
Laura Hopkins (media) 281-293-6030
Clayton Reasor (investors) 212-207-1996

Peabody

PEABODY ENERGY

c: RBowen
D.T
LS
File - Mstg Corsp.

701 Market Street
St. Louis, Missouri 63101-1826
314.342.3400

June 9, 2005

Mr. Phil Amick
Technology Director -Gasfication
Technology Solutions
ConocoPhillips
3002 Triangle
600 North Dairy Ashford
Houston, TX 77079 - 1175

Dear Phil:

As I mentioned in D.C., Peabody Energy is in developing a net 300 MW coal fueled power plant in McKinley County New Mexico. In light of the advances in the technology made possible by ConocoPhillips acquisition of the former Global gasification technology, I have requested that our team re-evaluate gasification technologies for possible deployment on this project. Since your technology is one of the industry leaders we would like to get your input on the feasibility for our project. If the Mustang coal or site location is not suitable for your IGCC process, please let us know.

In order to fully evaluate whether the ConocoPhillips' IGCC technology would be appropriate for our Mustang project we will need some input on a series of questions regarding the technology and operations and some high level cost estimates.

Baseline Plant Data:
We are limited to 300 net MW (+/- 10%) output due to transmission constraints.
The New Mexico coal available for this project has a high ash content (worst case 20%), low thermal content -HHV 8647 Btu/lb, medium sulfur - SO_2 3.5 lb/mmbtu, sulfur 1.556%, and average moisture of 15.76%. Attached is the trace analysis for this fuel.
The site elevation is 6,930 ft AMSL.
The plant will be located in McKinley County approximately 45 miles northwest of Grants, New Mexico. The area is considered remote with the nearest neighbor 4 miles away.
The facility will be limited to heat input of 3,192 mmbtu/hr.
Start-up fuel will most likely be fuel oil or propane.
Rail access is within 1 ½ miles of the facility site.

Information Required by Mustang to Assess Feasibility of Employing ConocoPhillips Technology:

- Based on the project information provided, can the ConocoPhillips process utilize the proposed fuel and site? If so could you provide references where a similar fuel has been utilized and projects completed at elevation greater than 5,000 ft AMSL. Please include information regarding how long the facility has been operating, performance and availability information (examples heat rate, degradation curves, monthly & annual availability). How much coal would be required on an annual basis at 100% rated output?
- Can you provide an indicative cost estimate for the facility (EPC basis)?
- It is expected that the facility will be project financed with third party off balance sheet debt. Would ConocoPhillips (or ConocoPhillips in a partnership or consortium with others) be prepared to provide a "full wrap" of the project with respect to schedule/completion, environmental, output, performance and availability guarantees, any others? What cap limits (either in % or absolute dollar value) would you be willing to accept for the guarantees? Please describe how the values would be calculated.
- Would ConocoPhillips be willing to consider equity ownership, financing, or any other financial options for a plant of this type?
- What site requirements would be necessary such as how many acres, quantity of water, any start-up fuel requirements such as natural gas, and other requirements?
- What emission limits would ConocoPhillips be willing to guarantee (in lbs/mmbtu based on 3 hr, 24 hr, and 30 day rolling average) for SO_2, NO_x, CO, VOC, PM_{10} filterable and condensable, mercury, HCL, HF, lead, and beryllium? These amounts would need to include emissions from any vents, flares, or stacks. If emissions are not controlled to the same levels during startup, shutdown, or reduced load operation please provide tables indicating emissions and duration during these processes.
- What quantities of waste would be generated by the facility and what type of disposal would be required? Any hazardous waste generated?
- Would you be able to provide estimates of operating costs and numbers of employees required for this type of facility? What length of time would be required for start-up of the facility –cold start, hot start, etc and what would be the load profile – what is the minimum load at which the facility can operate and what heat rate impacts might be expected? Would the facility be capable of load following?
- Many vendors of IGCC technology are advertising carbon sequestration ready. If your technology is capable of carbon capture, please describe the process and equipment required as well as any additional costs for this feature, assuming a 50% hydrogen fuel to the gas turbine.

- Could you meet a 2010 start-up schedule if construction began in mid 2006? How long would it take the facility to reach commercial status after first start?

The information requested above will allow us to evaluate your technology and determine whether a more detailed study to include a firm price for a turnkey project is warranted. Please provide an indicative price and time frame for completing a detailed study of this type with your response by July 1, 2005.

We appreciate ConocoPhillips interest in our project and look forward to receiving the information. Should you have any questions or require additional information on the Mustang Project please do not hesitate to contact Lars Scott at 314-342-7594. In addition, we spoke of coordinating a meeting whereby your group would give us a presentation on where ConocoPhillips is going with the business and discuss any other business opportunities with Peabody. Please email me with some dates and I will verify the availability of my team.

Sincerely,

Rick Bowen

Senior Vice President
President - Generation

MUSTANG

NEW MEXICO

Blend of all seams

TRACE ANALYSIS

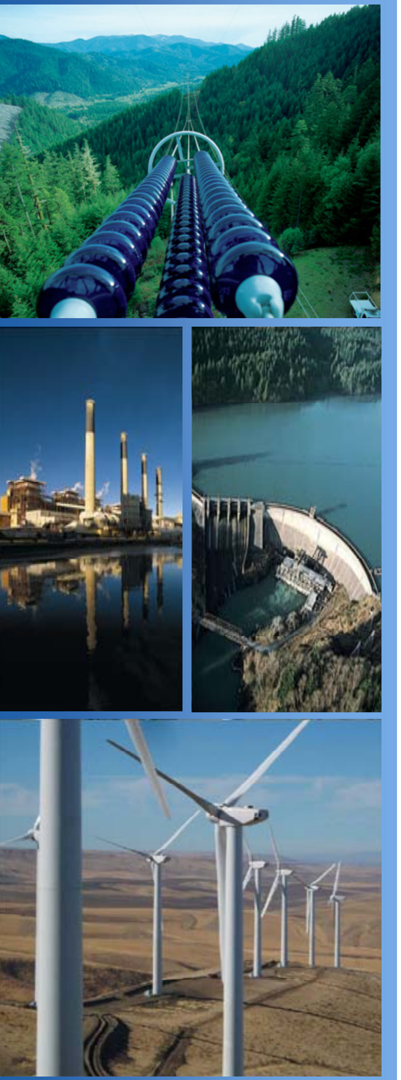
(DRY WHOLE COAL BASIS PPM)

Arsenic	6
Antimony	<1
Barium	87
Beryllium	1.1
Boron	55
Cadmium	0.6
Chromium	7
Cobalt	5
Copper	9
Fluorine	38
Lead	4
Lithium	17
Manganese	61
Mercury	0.12
Molybdenum	<2
Nickel	5
Selenium	2
Silver	<0.3
Strontium	142
Thallium	<1
Tin	<1
Uranium	1.6
Vanadium	5
Zinc	12
Zirconium	21

All analysis are subject to revision due to addition coring, conditions specified in the coal supply agreement, actual operating conditions at time of mining, type of preparation at time of mining, or federal and state regulations. Analysis intended for informational purposes only.

w.b.e 3/12/2002

EXHIBIT 2



IGCC Working Group

Jim Bridger IGCC Study

March 27, 2008

Overview

- Summary of Work Performed
- Deliverables
- Design Basis
- Summary of Proposals
- Technical Summary
- Summary of Results – (Blinded)
- Questions or Comments

Summary of Work Performed

- In July 2006, the Wyoming Infrastructure Authority (WIA) issued an RFP seeking a partnership to develop a Wyoming based IGCC facility to pursue federal co-funding under Section 413 of the US Energy Policy Act of 2005. Required key attributes:
  - Elevation above 4,000’
  - Coal heating value not to exceed 9,000 Btus per lb
  - 200 MW or larger
  - Sited in Wyoming
  - Carbon capture capable
  - Demonstrated project capabilities
- PacifiCorp worked with Siemens Power Systems and Kiewitt to prepare a proposal based on Siemens gasifiers and power generation equipment. Balance of plant effort prepared by Sargent & Lundy
- PacifiCorp submitted its proposal to WIA in October 2006
- PacifiCorp short listed in February, 2007

Summary of Work Performed

- WIA and PacifiCorp executed an MOU in April 2007 in which PacifiCorp agreed to perform detailed IGCC feasibility studies with one or more gasification technology providers.
- PacifiCorp agreed to spend up to $2 million to perform feasibility studies.
- PacifiCorp engaged Sargent & Lundy (S&L) in May 2007 to provide owner's engineer support
- WIA engaged RW Beck for technical support

Summary of Work Performed

- PacifiCorp issued an RFP to six IGCC technology companies in mid-July, 2007; responses by 8/2/07.
- Following companies/technologies made proposals:
  - Black & Veatch (Shell)
  - General Electric @ no cost
  - Siemens
  - WorleyParsons (ConocoPhillips "E-Gas")
- Mitsubishi (air blown gasifier) and Southern Company/Kellogg-Brown-Root (transport gasifier) declined

Summary of Work Performed

- Proposals were independently evaluated by PacifiCorp, RW Beck and S&L. The proposals / technologies were rank-ordered as follows:
  1. Shell
  2. ConocoPhillips “E-Gas”
  3. General Electric
  4. Siemens
- Engineering services contracts and confidentiality agreements were entered into with all four companies representing the various gasification technologies.

Confidentiality Agreements

- Confidentiality agreements were entered into with all four companies representing the various gasification technologies.
- These confidentiality agreements prevent PacifiCorp from making the study results available to outside parties.
- The summary content of this presentation has been reviewed and approved by Black & Veatch, ConocoPhillips, and Siemens.
- We can forward any requests for additional information to the technology providers.

Feasibility Study Deliverables

- Performance on syngas derived from design coal & natural gas at Jim Bridger & an alternate site:
  - Capacity (gross and net)
  - Heat Rate (gross and net)
- Capital (~+/-25%) and O&M cost estimates
- Water balances
- Summary level heat and material balances
- Criteria pollutant emissions (NOx, SO_2, PM_{10})
- CO_2 emissions
- Availability analysis
- Plot plan & general arrangement drawings

Feasibility Study Deliverables (cont'd)

- Interface requirements (water, coal, waste..)
- Cost estimate for CO_2 capture & performance impact of capture
- Project schedules
- System descriptions
- FEED scope and cost
- Commercial arrangement for project execution
- Documentation and support for federal funding application

Jim Bridger Plant – IGCC Site

Jim Bridger Site & Design Basis

- Jim Bridger is a coal-fired plant with 4 - 530 MW pulverized coal units
- Mine mouth plant
- Access rights to additional water from Green River
- Dedicated operations and maintenance staff
- Elevation: 6,620 feet
- Proposed new interconnection point for major interstate transmission system upgrades

Design Basis

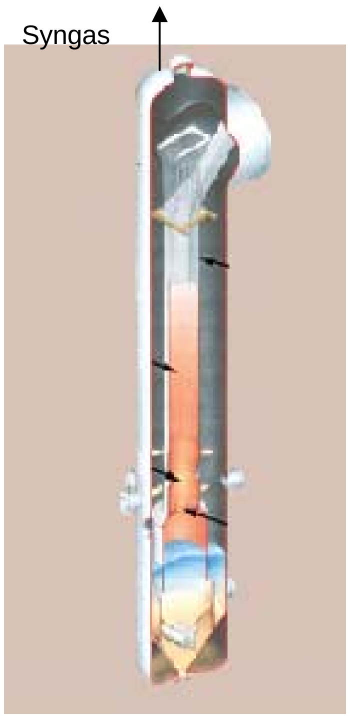
- Design coal: Powder River Basin, 8,800 Btus/lb
- Performance coal: Jim Bridger, 9,540 Btus/lb (one technology provider limited its study effort to a proxy PRB 8,800 coal only)
- Nominal Duct Firing (natural gas only)
- CO_2 capture levels design targets:
  - Better than California standard of 1,100 lbs CO_2/MWh (net)
  - Single stage shift – technology supplier identified ”sweet spot”
  - CO_2 delivered at 2500 psig (dry, H_2S less than 20 ppm)
- Average site ambient temperature: 41.6 degrees Fahrenheit
- Natural gas backup @ transmission pressure
- 500 kV delivery
- Alternate site (4,650’ using PRB-8,800 Btu/lb coal)

Many different kinds of gasifiers….

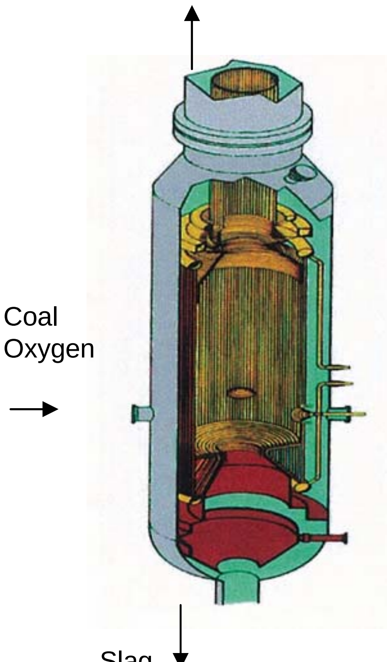
← Air-blown → ← Oxygen-blown →

← Dry-feed → ← Slurry-feed →

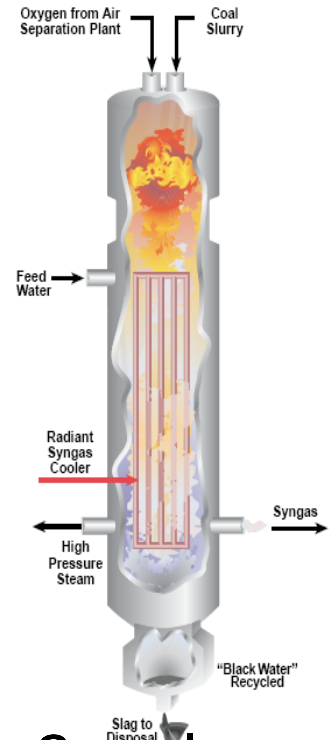
← Membrane Waterwall → ← Refractory →



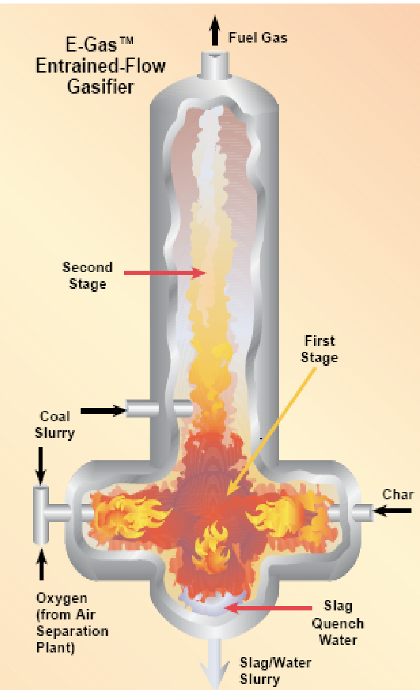
Mitsubishi



Shell

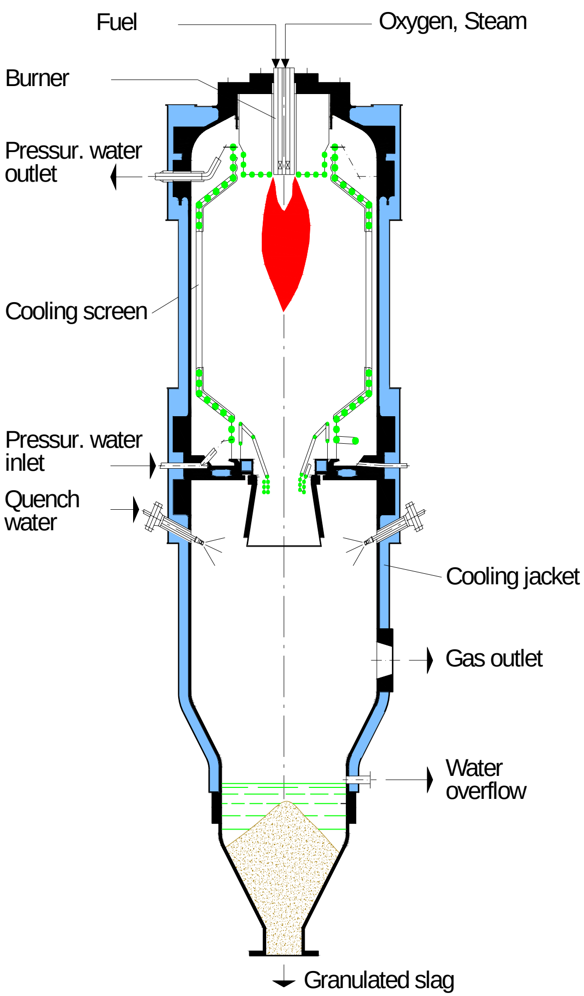


General Electric



Conoco-Phillips

Siemens Gasifier



General Electric

- Dry feed (with Stamet pump), entrained flow, oxygen blown, single stage, refractory lined, slagging gasifier
- Two (2) "Texaco" gasifiers feeding a 2x1 combined cycle utilizing GE 7FB gas turbines
- No constructor identified
- No PRB coal experience – Stamet pump is GE's low rank coal solution; needs to be demonstrated at scale. Scale injection technology also needs to be verified.
- Commercial IGCC experience (one operating IGCC plant in U.S.- TECO Polk); multiple GE gasifiers operating in world
- Provided summary level cost and performance information
- No results are presented due to difference in Jim Bridger design basis and General Electric's.

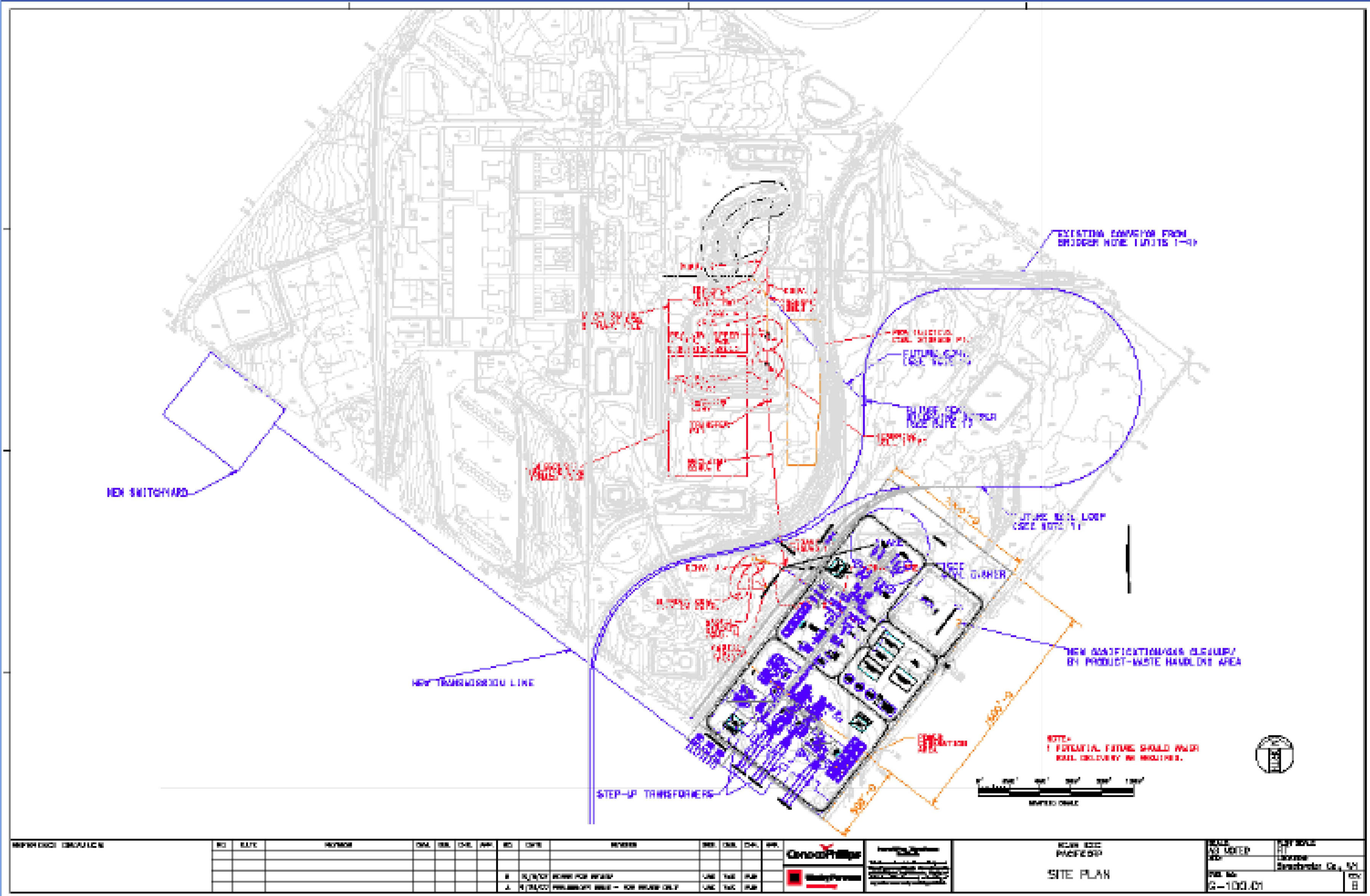
Siemens

- Dry feed, entrained flow, oxygen blown, membrane wall, single stage, quench, slagging gasifier
- Three gasifiers feeding 2x1combined cycle using Siemens SGT5000F gas turbines, Selexol acid gas removal system, SCR system
- Sour shift, single stage (single vessel) for CO_2 removal
- Proposed gasifier (500 MWthermal) – no experience at this size
- Constructor supported proposal (Kiewitt)
- CO_2 capture and IGCC experience minimal
- Low rank coal gasification experience (but not with PRB)
- Potential for a low cost gasifier
- Perceived to have greater promise of funding for gasifier development
- Technology has limited heat recovery from syngas cooling resulting in a lower steam turbine generator output than other technologies.

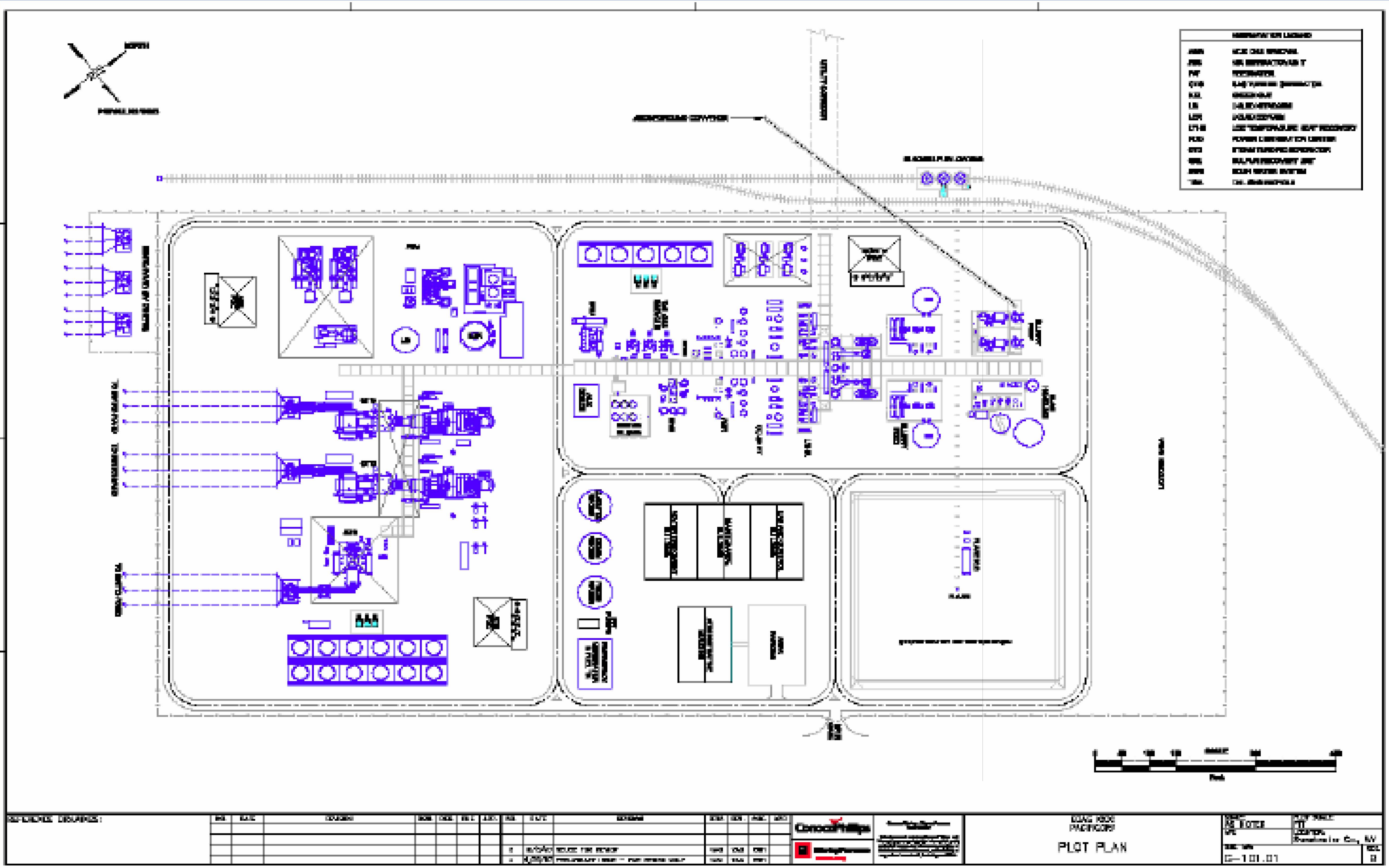
WorleyParsons ("E-Gas") Proposal

- Slurry feed, entrained flow, oxygen blown, refractory-lined, two-stage, slagging gasifier
- Two (2) "E-Gas" gasifiers feeding a 2x1 combined cycle utilizing Siemens SGT5000F gas turbines, Selexol acid gas removal system with SCR system
- Sour shift, single stage for CO_2 removal
- No constructor affiliation proposed (Zachry and TIC suggested)
- Qualified engineer for both process & CO_2 capture
- Low rank coal experience (significant commercial use)
- IGCC experience (one commercially operating at Wabash)
- EPCM contracting methodology proposed
- Highly integrated plant design utilizing compressed air from the combustion turbine to feed the Air Separation Unit. High degree of steam optimization.

WorleyParsons ("E-Gas") Plot Plan



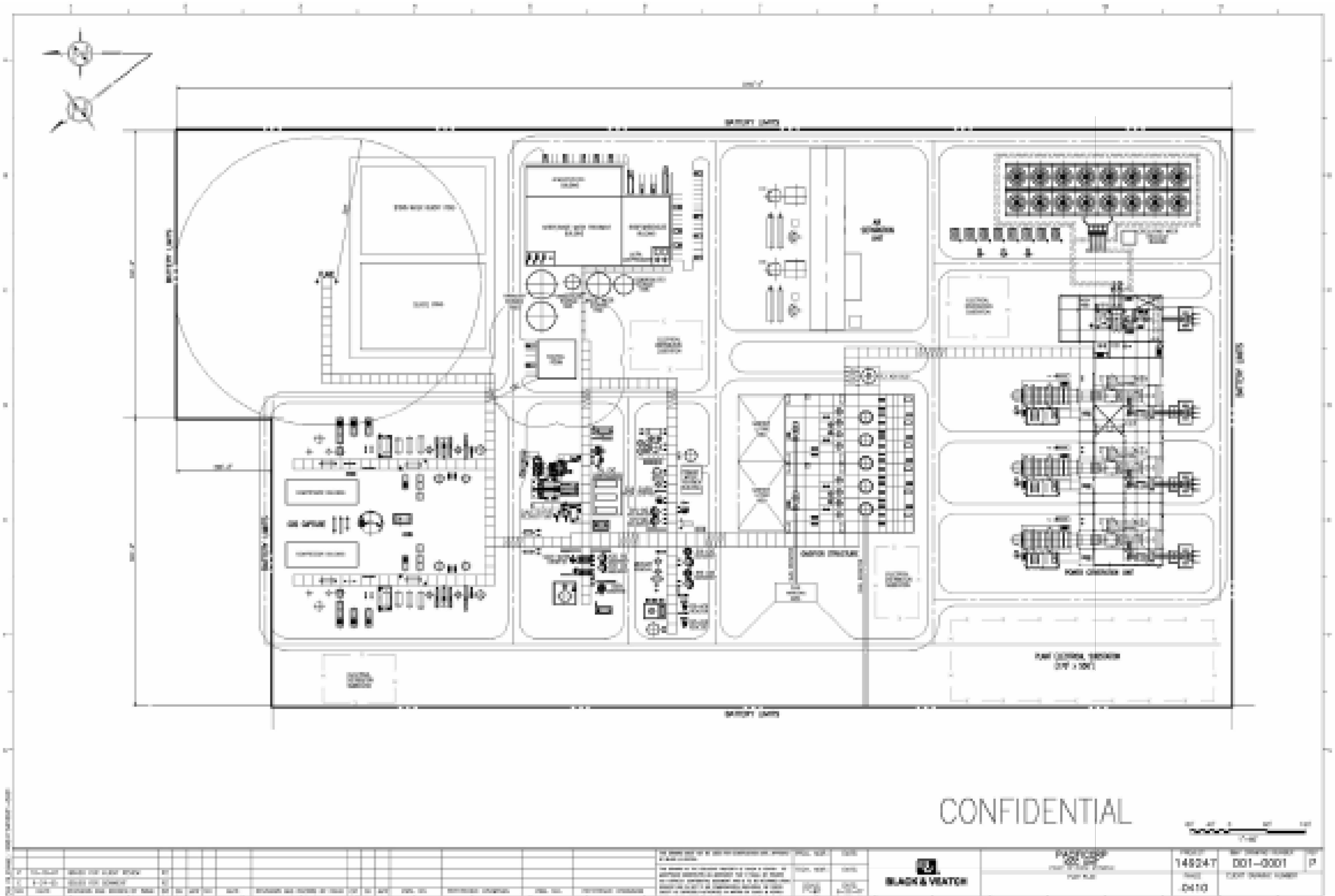
WorleyParsons ("E-Gas") Plot Plan



Shell

- Dry feed, entrained flow, oxygen blown, membrane wall, multi-injector, slagging gasifier
- Two (2) gasifiers feeding a 3x1 combined cycle configuration using GE 7FB gas turbines, Genosorb acid gas removal system, SCR system.
- Sweet shift for CO_2 removal
- No constructor as part of the proposal, but potential candidates identified with strong relationships
- Qualified engineer with broad gasifier & process experience
- IGCC experience (2 full scale commercial facilities in Europe) and multiple gasifier experience in the world
- Potential for funding for advanced gasifier development is perceived to be low but overall gasification technology risk is low.
- Although Shell technology is considered “most efficient” in the industry, not the case with CCS.

Black & Veatch (Shell) Plot Plan



Gasifier Comparisons (S&L)

Shell Rank: 1	ConocoPhillips Rank: 2	Siemens Rank: 3
The design has now been replicated in a variety of applications in China. This design is updated from the design demonstrated at Buggenum and is the most commercially tested of the 3 systems. The B&V design uses dry pulverizers to grind the coal; a review is needed to evaluate if the system can be operated safely on PRB coal. The Shell gasifier produces little H_2 requiring more shift conversion.	The design has been operating in an IGCC environment at Wabash and before that at LGTI for many years. Annual refractory maintenance is still an issue. Advanced refractory designs developed for DOE may improve maintenance requirements. The 2-stage gasifier design provides both high-efficiency energy conversion from coal, and the slurry feed yields high H_2 generation in the gasifier reducing the requirement for shift-conversion catalyst. The slurry feed system is simpler to operate and maintain than the dry-feed systems proposed.	The design has had excellent operational history at Schwarze Pumpe. The design shows promise but has not been replicated yet for new commercial facilities. There are several gasifiers currently in design. The Siemens design uses dry pulverizers to grind the coal; a review is needed to evaluate if the system can be operated safely on PRB coal. The Siemens gasifier produces little H_2 requiring more shift-conversion.

Gas Clean-Up Systems Comparisons (S&L)

ConocoPhillips Rank: 1	Shell Rank: 2	Siemens Rank: 3
The CoP design uses hot gas filters to clean the raw gas of particulate. This allows for maximizing the recovery of waste heat and production of steam. They have demonstrated excellent performance of this design at Wabash.	Shell uses recycled cooled syngas to quench the temperature of the raw gas leaving the gasifier to protect the waste heat recovery exchanger. This has proven effective at Buggenum, but is costly.	Siemens uses venturi scrubbing to clean the gas prior to waste heat recovery. This is a reliable and effective technology, but results in a lower process efficiency.

Performance Summary (Design Coal)

	A	B	C
Net Capacity on syngas, MW	**483**	**529**	**409**
Net Heat Rate on syngas, Btus/kWh	**11,350**	**11,765**	**12,361**
Annual Availability on syngas	**84.4%**	**79.3%**	**84.6%**
CO_2 Stack Emissions, lbs/MWh on syngas	**477**	**837**	**659**
Percent CO_2 Removal	**79%**	**66%**	**75%**

Performance shown is the expected long term value at average temperature.

Performance does not include duct firing capability.

Cost Summary ($/MWh, 2012 Levelized)

	A	B	C
Total Cost of Energy (Fuel, Capital, and O&M)	**$113.0**	**$133.7**	**$132.6**
Environmental Emissions Costs (CO_2 and criteria pollutants)	$2.85	$4.4	$3.5
Cost of Energy Plus Environmental Cost	**$115.6**	**$138.1**	**$136.1**
Market Value of Duct Firing Capability	($10.1)	($7.1)	($7.0)
Market Value of CO_2 ($0.50/thousand cubic feet, 2007$)	($9.1)	($7.7)	(9.1)
Cost of Energy net of Environmental Costs, Duct Firing Benefit & CO_2 Sales	**$96.4**	**$123.3**	**$120.0**

$133 million investment tax credit would lower IGCC cost of energy

by ~ $3-3.50 MWh

Supercritical Pulverized Coal Cost of Energy (no CO2 capture) = $65/MWh

Alternate Site Performance Summary

	A Design Coal	B Design Coal	C Design Coal
Capacity, MW, New & Clean, 4,650’	512	588	469
Heat Rate, Btus/kWh, New & Clean, 4,650’	11,171	11,514	11,724?
Capacity, MW, New & Clean, Bridger	498	545	422
Heat Rate, Btus/kWh, New & Clean, Bridger	11,151	11,518	12,148

Impact of Varying CO_2 Capture Levels

	A Design Coal	B Design Coal	C Design Coal
Capacity, MW, New & Clean	498	545	422
Heat Rate, Btus/kWh, New & Clean	11,151	11,518	12,148
Capacity, MW, New & Clean, Max Removal	490 (90% removal)	522 (90% removal)	408 (~83% removal)
Heat Rate, Btus/kWh, New & Clean, Max Removal	12,565	12,565	12,759
Capacity, MW, New & Clean, Capture Off	557	589	466
Heat Rate, Btus/kWh, New & Clean, Capture Off	9,251	10,643	10,985
EPCM Capital Cost Attributable to CO_2 Capture	17%	12.5%	13-15%

Availability during Initial Years of Operation

	A	B	C
First Year Expected Availability	**70%**	**63%**	**55%**
Second Year Expected Availability	**80+%**	**72+%**	**76%**

Water Consumption

	790 MW Supercritical Pulverized Coal	A	B	C
Water Consumption, GPM	**5,530**	**4,500**	**4,642**	**5,344**
Water Consumption, Gallons/MWh	**421**	**542**	**511**	**759**

Average annual consumption rates at average temperature with no duct firing

Pulverized Coal is Jim Bridger Unit 5 with no CO_2 capture

Summary of Conclusions

- Performance differences between Bridger coal and 8,800 Btu-PRB coal are relatively minor.
- Contracting methodology has a significant impact on cost of plant; still major capital cost uncertainty; market reluctant to provide "full-wrap" lump sum turn key pricing.
- Federal EPACT income tax credit provides minimal benefit

Summary of Conclusions (Cont'd)

- Long term marketing of CO_2 for enhanced oil recovery necessary to overcome cost and performance premium
- Some improvement in overall performance and cost of energy at lower elevation (depending on technology); needs to be balanced against transmission, coal and water availability
- Front End Engineering Design (FEED) studies are $20+ million.

EXHIBIT 3

CALCULATION OF INCREMENTAL COST EFFECTIVENESS
DRY FORK STATION, GILLETTE, WYOMING
APRIL 29, 2008
REVISED JULY 1, 2008

CALCULATION				
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)	$27.25	Escalated 10%	$28.60	Escalated 10%
Non Fuel Variable O&M ($/kWh-yr)	$0.0063	Escalated 10%	$0.0066	Escalated 10%
Fuel Cost ($/MMBtu)	$0.57	See Report	$0.57	See Report
Capital Cost (M$)	$1,485.00	Escalated 10%	$1,930.50	Escalated 10%
Capital Cost ($/kW)	$4,035.33	Calculated	$5,245.92	Calculated
EMISSIONS	**PC**	**Source**	**IGCC**	**Source**
SO2 (lb/MMBtu coal feed)	0.070	Dry Fork Permit	0.010	See Report
NOx (lb/MMBtu coal feed)	0.050	Dry Fork Permit	0.011	See Report
PM (lb/MMBtu coal feed; filterable only)	0.012	Dry Fork Permit	0.0063	Basin, p. 21
CO (lb/MMBtu coal feed)	0.150	Dry Fork Permit	0.036	Basin, p. 21
VOC (lb/MMBtu coal feed)	0.004	Dry Fork Permit	0.001	Basin, p. 21
CO2 (ton/hour)	379	See Report	357	See Report
COSTS	**PC**	**Source**	**IGCC**	**Difference**
Annual Output (MWh-net/yr)	2,740,128	Calculated	2,740,128	0
Annual Heat Input (MMBtu/yr)	27,612,270	Calculated	26,031,216	-1,581,054
Capital Recovery Factor (%)	6.57	Calculated	6.57	0.00
Annual O&M Total (M$/yr)	27.26	Calculated	28.61	1.35
Annual Debt Service (M$/yr)	97.54	Calculated	126.80	29.26
Annual Fuel Cost (M$/yr)	15.85	Calculated	14.94	-0.91
IGCC SCR Cost (Annualized Capital + O&M) (M$/yr)	-	See Report	6.45	6.45
Total Annual Cost (M$/yr)	140.65	Calculated	176.80	36.15
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

COST EFFECTIVENESS				
INCREMENTAL COST EFFECTIVENESS, PC vs. IGCC	**PC Weight Fraction**	**TAC ($/yr)**	**Emissions Delta (tons/yr)**	**Cost Effectiveness ($/ton)**
SO2	0.245	8,857,516	836	$10,591.65
NOx	0.175	6,326,797	547	$11,563.50
PM (Filterable) Emissions Delta, tpy	0.042	1,518,431	84	$18,146.71
CO	0.525	18,980,391	1,602	$11,845.28
VOC	0.013	468,183	38	$12,298.89
Total (All of Above)	1.000	$36,151,317.87	3,108	**$11,633.54**

EXHIBIT 4

Projected cost for new Alliant coal plant soars past $1 billion

Jeff Richgels
June 15, 2008

The cost for Alliant Energy's controversial proposed new coal power plant has soared to a range of $1.1 billion to $1.2 billion, the company stated in a regulatory filing.

Alliant previously said the new plant proposed to be the third unit of the Nelson Dewey Generating Station in Cassville would cost $850 million to $950 million. When initially proposed in 2007, the plant's cost estimate was under $800 million.

The company is facing heavy opposition from environmental groups as it seeks approval from the state Public Service Commission to build the 300-megawatt plant. Cassville is its top site option, while the Columbia Generation Station at Portage is No. 2.

Alliant also said in the filing that its cost estimate for capital expenditures for sulfur dioxide air pollution controls at the two existing coal units at Nelson Dewey would be about $200 million, nearly double the previously disclosed estimate of $116 million.

Company officials said the increases stem from soaring construction costs that include big cost hikes for items such as concrete and steel.

Alliant also announced that it would take several steps to reduce greenhouse gas emissions if the new plant is approved. The changes would be implemented by the time the proposed new plant would become operational in 2013 and would more than offset the carbon emissions from the new coal plant, the company said.

The company said late Thursday the changes are expected to cost about $500 million to $550 million, if all the necessary regulatory approvals are received.

Changes include the shut down of its oldest coal-fired generation unit, Edgewater Generating Station unit 3; ramping up its wind power segment; doubling its proposed renewable energy investments; and "aggressively" focusing on energy efficiency measures.

Under its new proposal, WPL aims to generate 500 megawatts of new wind power by 2013, compared with a previously announced plan to produce 300 megawatts of new wind power by the end of 2010.

Sites for the wind farms have not yet been determined, but the company said a possible site is southwestern Wisconsin.

Alliant also plans to double the amount of renewable resource fuels -- including switch grass, waste wood, or corn stalks -- to be used at the proposed new coal plant to 20 percent.

The company said analysis by researchers from the University of Wisconsin-Madison has shown that could create economic development revenues for Wisconsin exceeding an estimated $50 million annually.

"Alliant Energy is committed to reducing greenhouse gas emissions," Barbara Swan, president of Alliant's state utility unit, Wisconsin Power & Light Co., said in a statement. "We believe our proposal addresses the critical balance of meeting important environmental objectives with the equally important goal of providing reliable and affordable power to our customers."

Alliant said its customers' two main concerns are protecting the environment while keeping the cost of electricity affordable.

Alliant's plans, though, were slammed by Clean Wisconsin, the state's largest environmental advocacy organization.

Clean Wisconsin said even with the moves, the new plant still would be one of the state's dirtiest power facilities.

"Alliant continues to repackage their proposal in an attempt to sell this dirty coal plant as an environmentally friendly option," Katie Nekola, energy program director at Clean Wisconsin, said in a statement. "Replacing a nearly retired coal plant that emitted less than 500,000 tons of carbon dioxide in 2006 with one that would emit more than 2.3 million tons of greenhouse gas annually for at least 50 years is not a solution to global warming."

Even at 20 percent biomass, the Cassville plant would emit more greenhouse gas emissions than other, more efficient, power plants fueled exclusively by coal in Wisconsin, Clean Wisconsin said in a news release.

The organization also noted that the PSC has questioned many details of Alliant's previous commitment to burn even 10 percent biomass in the recent environmental impact statement.

And Clean Wisconsin noted that the announcement comes one month after the PSC released a draft environmental impact statement that said Alliant's proposal was "not the optimal generation choice," and "not the least cost option under any scenario."

"The estimated costs of Alliant's expansion plans are skyrocketing and the construction of the coal plant alone will likely cost over $1 billion," Nekola said. "If this plant is built, Wisconsin energy users will shoulder the burden of the construction costs and future greenhouse gas regulations."

"While Alliant is once again trying to repackage this coal plant, the fact remains that it is a coal plant at heart," Nekola added. "The high costs and substantial greenhouse gas emissions of this plant make it a bad investment for Wisconsin's economy and environment."

Groups opposed to the plant, including the Citizens Utility Board, have called on Alliant to beef up spending on energy efficiency and renewable energy instead of building a more costly coal plant.

Alliant has said that its analysis and analysis by the PSC has shown the need for a new power plant, given the rising demand for energy.

The PSC is expected to vote on the plant proposal by the end of the year.

A week earlier, Alliant-WPL filed an application with the PSC for a new wind farm in Freeborn County, Minnesota, where the company said there are "the strong and persistent prairie winds of southern Minnesota."

The Bent Tree Wind Farm, near Albert Lea just north of the Iowa border, could produce up to 400 megawatts of power for about 100,000 homes. The application seeks approval for a $450 million to $475 million project to develop approximately 200 megawatts of power beginning in 2009.

Assuming approvals by the PSC and the Minnesota Public Utilities Commission, the wind farm would be operational by 2010, the company said.

"Developing Bent Tree Wind Farm is the next logical step in WPL's commitment to not only wind energy, but all renewable energy," Swan said in a statement. "We will continue to seek environmentally friendly alternative sources of energy to complement our baseload generation initiatives, which furthers our goal of providing reliable, affordable and environmentally responsible power to our customers."

In April, WPL executed a letter of intent to purchase Bent Tree from Wind Capital Group LLC. WPL currently anticipates the purchase of the site to be complete by October 2008.

Bent Tree would be WPL's second fully owned and operated wind farm. The company's first such project, the Cedar Ridge Wind Farm, a 68-megawatt project in Fond du Lac County, is expected to begin commercial operation later this year.

WPL expects the PSC to rule on its Bent Tree application by the end of the year and the Minnesota PUC to rule by late 2008 or early 2009.

To fulfill its anticipated wind needs, Alliant announced that it will buy 303 wind turbines from Vestas-American Wind Technology Inc. for about $817 million. Deliveries will begin next year and continue through 2010.

The turbines, to be used by WPL and Alliant's Iowa utility unit, Interstate Power and Light Co., will have a total installed capacity of 500 megawatts. IPL is developing a 200-megawatt wind farm in Franklin County, Iowa.

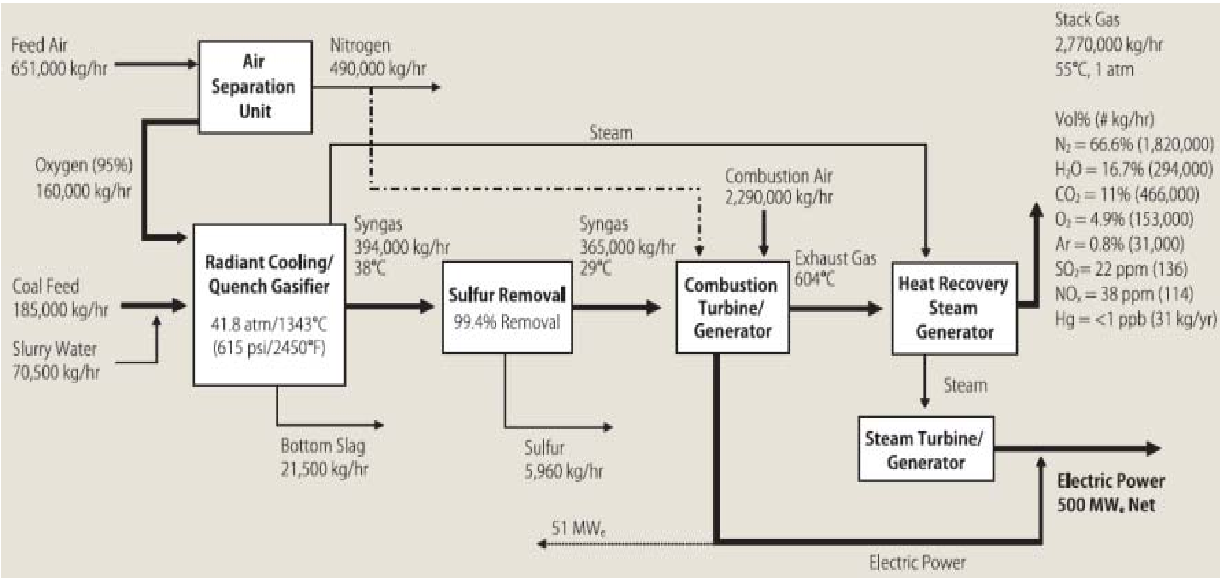
A one-megawatt plant running continuously at full capacity can power 778 households each year, according to the U.S. Department of Energy.

"Our company is pleased to partner with Vestas, who is a recognized leader in the wind generation industry," Kim Zuhlke, Alliant Energy vice president of new energy resources. "Vestas will play an important role in our company's next step in expanding its renewable energy supply portfolio. Given our company's aggressive wind generation expansion plans, we believe it is important that we procure the infrastructure necessary to complete the generation build-out on-time and at a reasonable cost to customers."

Return to story

EXHIBIT 5

Figure 2 – Generic IGCC Block Flow Diagram



Reproduced from page 123 of "The Future of Coal", MIT, 2007.