Response to Request for Information on the Department of Energy's Plan to Restructure FutureGen

Comments Submitted by: American Electric Power Service Corporation
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Background

American Electric Power has been involved in the FutureGen Alliance from its inception. AEP has been a very active member of the Board of Directors and numerous of our engineering staff have participated in the Technical Committee, developing the initial conceptual design and in preparing RFI and RFP documents Equally relevant, AEP has been instrumental in early commercialization of CCS technologies through partnerships with Alstom, B&W, and Battelle and currently has a project underway to scale up the Chilled Ammonia process to 20 MW with integrated CO_2 compression and permanent saline aquifer storage. Pending success at the 20 MW scale, we plan to move forward with the first installation of the technology at commercial scale. AEP continues in its efforts with B&W to move development of Oxycoal to a commercially viable option for CO_2 capture American Electric Power has, over the past several years, built a significant engineering staff focused on the engineering and construction of multiple IGCC plants within our service territory. AEP engineering staff includes chemical engineers who have previously designed and operated gasification plants in the petro-chemical industry. It is because of this and other expertise that we believe AEP's comments to DOE's RFI are well-conceived and relevant.

Introduction

American Electric Power applauds the Department of Energy for its stated goals to accelerate the advancement of clean coal technologies as a vital component of reliable, affordable, and a more secure energy future One key focus of this effort is clearly the commercialization of CO_2 capture and storage The objectives of FutureGen for demonstrating new and more advanced technologies make it unique among clean coal projects Therefore, AEP finds the recent DOE decision to withdraw support of FutureGen regrettable In a time of unprecedented attention on climate change, it is critical to maintain focus on the need to develop technologies and commercially demonstrate more cost-effective solutions for CCS

Regardless of any change in direction by the DOE, the spirit of the various clean coal programs should remain unchanged from the goals established for FutureGen These goals lead to the development of new technology, resulting in commercial-scale demonstrations. One lesson to be learned from recent events is that DOE must establish clear guidelines and goals for the development of advanced technology, and must be firmly committed to any revised program without hesitation or equivocation, be it now or in the future

AEP supports a near-term CO_2 reduction program that contemplates, in part, supporting the same goal as the Secretary now espouses, which is to encourage early CCS projects that are applied to commercial-scale power generation facilities This program must be committed to deploying CCS technology for both gasification and combustion-based power plants. It is critical to include combustion-based systems, since today they represent virtually the entire coal-based fleet and will be a majority for at least the next 20 to 30 years AEP offers a response to the RFI in an effort to help make DOE's new plan coherent, relevant, and viable It must be abundantly and unambiguously clear to the public that the restructured program is robust, and that it includes guaranteed long-term support and backing by DOE and the U S Federal Government in support of deployment of CCS as part of the long-term solution to reduce GHG emission.

Overview

AEP's comments will focus on the following points:

1. CCS today is expensive, both in terms of capital and operating costs Leveraging opportunities to reduce cost through EOR or regional partnership efforts should be allowed and encouraged.

2. The 90% CO_2 capture goal of FutureGen is aggressive and will likely be achieved over time as technologies develop and are demonstrated However, integrated operation of IGCC with CCS and a high-hydrogen turbine represent considerable risk for commercial power plant applications in the near term DOE should support alternative strategies for achieving the RFI goal of 45% CO_2 capture, which is currently stated as 90% capture from 50% (one train) of the generating unit

3. Post-combustion projects should be included in this restructuring of FutureGen. The need is great and other existing programs do not offer enough funding to support the multiple projects necessary to bring these various technologies to the marketplace

4. Integration of CCS into IGCC or PC plants is very costly DOE must provide assurance of cost share for these modifications.

5 DOE project contributions must consider operating cost impact in addition to capital costs

6. Project funding must be assured up front. Annual appropriations as they currently have been handled for FutureGen offer too much uncertainty for commercial entities

7 DOE must allow for adjustments in project cost due to scope uncertainty and normal escalation

8. If the NEPA process will be required, it is necessary for DOE to commit to the timeline required to compete the process

9 To maximize possible participants, provisions must be in place for the protection of intellectual property associated with the project

10. CCS implementation represents significant capital and operating cost to the operator As such, the DOE must not have a funding repayment requirement

11 DOE should not require approval rights for subcontracts

12 The industrial participant must have full and unencumbered title to the facility

13. AEP has identified a number of existing facilities as well as potential future sites where CCS projects would be feasible

Technical Comments to the DOE RFI

1. *Flexibility with CO_2 Storage Requirements*

CCS today is expensive, both in terms of capital and operating cost Technologies with better economics must be developed and demonstrated at a commercial scale before wide deployment may be accomplished Therefore, commercial demonstrations must be strategically planned such that the projects leverage the needs for various generation technology applications with geologic-storage opportunities. Where possible, opportunities to obtain cost offsets through the re-use of CO_2 must be considered Merging CO_2 capture installations with regional partnership storage projects will provide additional benefits

The RFI requires that at least one million metric tons per year of CO_2 be stored in saline aquifer formations and the rest may be used for other purposes but ultimately permanently stored While most applications likely will offer no options besides saline aquifer storage, there may be some cases where EOR or other applications may be viable and economically justified Where offset revenue can be found, the high cost of a project could in part be mitigated It would be fiscally irresponsible to disallow the use of such mechanisms

AEP recommends permitting the use of EOR wherever available MMV techniques may still be developed and proven through EOR operations and the cost of CCS would be minimized in the process. AEP is still supportive of multiple deep saline aquifer projects, therefore, cooperating with regional partnership efforts must also be investigated

2. *Regarding 90% CO_2 Capture and Other FutureGen Emissions Goals*

The capture and emission goals of FutureGen are likely to be achieved over time as technologies develop and are demonstrated However, integrated operation of IGCC with CCS and a hydrogen turbine represent considerable risk for commercial power plant applications in the near term The proposed target of 90% CO_2 capture on a single gasification and power generation train necessitates the deployment of technology beyond what is currently commercially available, particularly with respect to the combustion turbine Reconfiguration of the present RFI language can still accomplish the goal of more than 1 million metric tons per year CO_2 storage while still enabling a power plant to operate under real-world conditions with the reliability necessary for commercial operation A long-term strategic implementation plan can be developed to take the capture process, in a logical and stepwise manner, from levels achievable with current technologies to an eventual goal of very high levels of CO_2 capture. In much the same way as CO_2 targets, some of the other emission requirements must be relaxed somewhat to enable commercial deployment

Requiring 90% CO_2 capture on a 300-MW IGCC power train, using currently-available technologies, places undue risk on commercial entities. If implemented as a retrofit on a commercial IGCC plant, the following is a sample list of blocks in the effected train that would be impacted:

1 COS hydrolysis would be deleted
2 A two-stage shift reactor would be added.
3 The AGR would be split into two trains The AGR for CO_2 capture would need the following changes above the equipment for the non-CO_2 AGR
   a Addition of at least one CO_2 absorber
   b Addition of several flash drums
   c Addition of at least two compressors, one to recover co-absorbed hydrogen in the CO_2 section, the other to recover co-absorbed H_2 from the sulfur section
   d Additional equipment to replace the rich flash drum

e. Additional refrigeration capacity
f. Several additional pumps, including semi-lean solvent and loaded solvent.

4. Additional MAC capacity for the ASU due to loss of extraction air from the CT operating on H_2. This may be best handled with two separate ASU's.
5. CO_2 compression / pumps.

It would be possible to operate the portion of the AGR for non-CO_2 capture in parallel with the portion for CO_2 capture using a common regenerator, which is the current configuration. However, operating these units with a common regenerator would likely introduce turndown, reliability and availability issues.

If we implement the capture of CO_2 by recovering about 45-50% of the CO_2 from the syn gas from both gasifiers, which would still meet the DOE's CO_2 storage goal, the changes would be similar to those above, with the following exceptions.

1. A one-stage shift would be needed.
2. Assuming that we would keep the present AGR configuration of two parallel absorbers and a common regenerator, the AGR would be two parallel trains with essentially all of the above-listed equipment needed for each train; however, the equipment would be smaller.

In summary, the concept of shifting one train for 90% CO_2 removal while operating the second without a shift is just not practical. Beyond the details presented above, AEP would be faced with the requirement of implementing a hydrogen turbine under current RFI requirements. Presently, no turbine in the F- or G-class has been commercially demonstrated to enable utilization of a high-hydrogen fuel, regardless of some OEM's claims. If the hydrogen stream were to be blended with the un-shifted syngas stream prior to combustion, the turbine could likely tolerate the fuel and the risk would be reduced. Further, the use of non-parallel trains adds significant uncertainty of long-term reliability and leaves the unit significantly less flexible from an operations standpoint. Loss of the non-shifted gasifier or AGR train would leave the turbine with a high-hydrogen fuel. This would necessitate bringing the entire unit out of service to protect the combustion turbine. The risks and loss of flexibility for the commercial operator are much too great to accept or tolerate. The risks for DOE of this requirement are that there will be no commercial participants for the restructured FutureGen.

AEP recommends an approach that will achieve the same ultimate CO_2 reduction goal, but through a strategy that minimizes the operational risks and is tolerable to the utility interests. A reduction of 90% of the CO_2 from 50% of the unit is the current requirement. This number equates to a reduction of 45% CO_2 from the entire complex. AEP's suggestion is to require 45% CO_2 capture from the total syn gas stream and at least one million metric tons CO_2 storage per year. This approach accomplishes the same amount of CO_2 being stored, same quantity captured from the unit, and does so without unnecessarily jeopardizing the operational integrity of the facility. Higher levels of capture can be approached over time in a stepwise fashion as the technology becomes available for the process and, most importantly, for the turbine.

AEP also recommends the DOE not focus on 90% capture as the endpoint target. It is understood that the cost to capture CO_2 is directly proportionally to the amount captured, up to some as yet unclear point, beyond which costs will increase dramatically. It is likely with today's technologies that such an inflection point occurs somewhere short of 90%. While FutureGen was able to ignore such economics because of the R&D nature of the facility, any commercial operation will be very sensitive to these dynamics and could be unnecessarily compromised if the 90% target becomes the accepted standard, prior to its viable demonstration.

3. ***Including Post-Combustion Applications***

CCS project demonstrations should not be limited to IGCC applications Pulverized coal plants represent virtually the entire fleet of coal-fired generation facilities today and will likely remain in the majority for the next 20 to 30 years. Current retrofit CO_2 capture technologies impose extraordinarily high parasitic demands on generating units, robbing as much as one third of the unit's output capacity. New and developing concepts offer the promise of efficiency improvements that greatly reduce their impact on power plant output. These advanced technologies must be commercialized before CO_2 can be controlled on the bulk of the coal fleet in any near-term scenarios

Given the present technology picture, IGCC with CCS may likely offer the low-cost path towards coal-fired electricity generation. However, there are sufficient unknowns and risks that we should not abandon alternative options Post-combustion and oxycombustion concepts are very active areas of focus and require significant funding and demonstration before they become sufficiently mature for retrofit or new generation implementation.

AEP believes that there is not yet a clear winner for best path towards low CO_2 emission from coal Pre-combustion and post-combustion applications will both exist into the foreseeable future. However, the majority of the need will be post-combustion-based, because they comprise the bulk of today's coal-based generation fleet The DOE should consider all CCS options when selecting the best projects to pursue. CO_2 capture requirements should provide the applicant with maximum flexibility, as described previously under point 2 for IGCC applications The parameters for post-combustion CCS projects should include 45-50% total CO_2 capture from a generating unit with a minimum of one million tons per year CO_2 into direct storage or re-use storage

4. ***Inclusion of Associated Plant Modifications for CCS***

Integration of CCS into IGCC or PC plants is costly As described in point 2 above, there are significant changes to the IGCC plant that will be required to accommodate CCS Many of these will not be identified until a detailed engineering study is completed It is clear that adding CCS to an IGCC, while doable, is non-trivial and is more involved than simply bolting on a few additional pieces of equipment to an existing system. Similarly, post-combustion and oxy-combustion retrofits impact plant systems and equipment outside of the CCS portion of the plant

AEP is recommending that DOE provide assurance of cost share for necessary balance of plant modifications at the same rate as for the CCS systems

5. ***Covering Increased Operating Cost***

The operation of CCS at a commercial power plant increases the production cost and reduces the net output of the facility Large amounts of CO_2 capture requires significant quantities of steam to be extracted from the power cycle for solvent regeneration, whether on IGCC or in a post-combustion application Particularly with the proposed 90% capture level, the steam demand appreciably increases the cost of electricity associated with the controlled generating unit. As a result, the unit will be penalized with respect to economic dispatch.

AEP recommends that any DOE project contributions must include incremental operating costs associated with system operation These costs should be contributed at the same cost share ratio as the capital costs. An alternative option is that incremental O&M costs be counted as cost share by the award recipient.

6. ***Funding Assurance***

Project funding must be assured up front. Annual appropriations, as they currently have been handled for FutureGen, offer too much uncertainty for commercial entities. Regardless of the reasons behind the restructuring of FutureGen, the public perception and that of industry is that DOE reserves the right to change its mind and is not required to honor cooperative agreements

The DOE proposes $1.3 billion in funds for the restructured FutureGen projects However, only $156 million has been appropriated and is currently all that is available. Furthermore, to date, Congress has not appropriated the full amount requested each year by the Administration for FutureGen A process involving annual approval and appropriations will not offer enough assurance to attract commercial operators

AEP recommends that DOE must obtain sufficient, authorized, and appropriated funding to assure meaningful contributions, as is currently done with CCPI. This funding guarantee must be in place before issuing the competitive Funding Opportunity Announcement Without this assurance, it may be difficult for DOE to attract serious bidders

7. ***Cost Escalation***

There is considerable uncertainty associated with the cost of a new CCS system Further, with escalation of costs of construction materials, basic commodities, and labor, it is inappropriate for the industrial participant to take on all the risk of cost growth and escalation.

AEP recommends DOE must allow for adjustments in project cost due to scope uncertainty and escalation

8. ***Concerning NEPA Process***

The NEPA process can be very time consuming and can lead to significant project delays

AEP believes that if the NEPA process is required, it will be necessary for DOE to commit to a clear and unambiguous timeline required to compete the process

9. ***Concerning Intellectual Property (IP)***

Since this is a commercial plant, it is important that the participant not be required to share any of the IP with third parties Without well-defined intellectual property protection, the technology options for this program would likely be considerably limited.

AEP recommends that DOE assure the offerer that it will not be required to share any IP with the DOE or other third parties.

10. ***Plant Revenues and DOE Contribution Repayment***

Operation of CCS systems represents a financial liability to the plant The operator will experience a net cost, not revenue, as a result of the installation and operation of the CO_2 capture and compression systems

AEP recommends that power plant revenues must not be shared with the DOE and there must not be a requirement for repayment of DOE contributions.

11. *Subcontractor Approval by DOE*

Since this is a major commercial plant, it is necessary that the DOE does not have any approval rights for any of the subcontracts. Otherwise, there is significant risk for project delays due to administrative issues with the DOE.

AEP recommends that there be no requirements by DOE for subcontractor approval

12. *Concerning Title to Facility*

AEP recommends the industrial participant must have full and unencumbered title to the facility

13. *AEP Host Sites Offered for Restructured FutureGen Program*

AEP has identified a number of existing generation sites as well as potential future sites where CCS projects would be feasible, including the potential to store large quantities of CO_2 in deep geologic formations One example of a potential project site is at the Mountaineer Plant, where a previous DOE-funded 9,200-ft characterization well was drilled The site has adequate infrastructure and has been identified for the construction of a new IGCC power plant AEP is currently installing a 20-MW CCS demonstration at Mountaineer for startup in 2009. At some sites there may be opportunity for EOR activities, such as AEP's announced installation of Alstom's Chilled Ammonia process at commercial scale at the Northeastern Plant in Oklahoma. Due to the lack of sufficient time to fully investigate, this response will not state additional details associated with the potential project sites

Summary

AEP's decision regarding submittal of a proposal in response to the upcoming Funding Opportunity Announcement (FOA) will be largely dependent upon the terms of the final DOE announcement. The concerns laid out in this response are very important to AEP, particularly the performance requirements and the considerations with respect to the approach for capturing the required amount of CO_2. A mandated 90% CO_2 capture presents a risk to plant operations that is likely too onerous for AEP or any other commercial entity to absorb That requirement alone could result in unwillingness from any applicant to pursue this opportunity.

February 10, 2008

Mr. Miles,

I would like to suggest subsystems for the total IGCC system be considered in the FutureGen program. Make a mechanism such that a subsystem can be tested independently and then integrated with the complete system when warranted. Implementing a mechanism to kick start new technologies to catch up enough with existing technologies so reasonable performance comparisons can be made would be useful. Maybe the DOE could connect individuals with larger companies that receive funding to integrate a sub-grant. Some companies have so much time and money invested in their own technologies it is not economical and disruptive to consider something unproven.

Please note the described solid fuel reactor fuel/oxidant feeder system and reactor modifications have not been patented. The basic reactor, condensing heat exchanger and steam generator patents are issued, 3 patents.

I have forwarded the inquiry to the DOE for an unsolicited grant to provide you a brief overview of the continuous solid fuel plug flow reactor. The plug flow allows possible applications not possible with the two existing solid fuel reactor modes. Close coupling the reactor to a gas turbine for an IGCC system that eliminates the gasification processes and compressor section of the turbine is one potential. The fuel plug flow will seal the back pressure of the reactor to allow continuous feed and coupling to a turbine. Making the outer gas tube the cathode that oxygen passes through for a solid oxide fuel cell should be considered. The inner solid fuel nozzle/tube will gasify the coal, the gases flows to the gas tube, the oxygen would pass through the gas tube outer shell (cathode) to combine with the produced gases.

The ideal over all system would be as follows; the solid fuel is fed into the solid fuel nozzle continuously; the hot oxidant (oxygen, steam, hydrogen peroxide, chemicals) is feed in the fuel plug core to gasify the solid fuel; the fuel/oxidant feeders can be controlled by a gas sensor/control system, fuel threw put can be increased/decreased as desired; produced gas stream and fuel ash stream are separated, the produced gases pass radially through the fuel plug and enters into the gas tube; oxygen passes through the gas outer tube wall cathode (a fuel cell) for chemical reaction and to produce electricity; The resultant hot gas stream leaves the gas tube, passing over the dry steam generators and powers a gas turbine directly (the nozzle is the turbine combustion can) to produce electricity; the gas turbine exhaust passes through a condensing mode heat exchanger creating wet steam, the wet steam moves through one or more dry steam generators located between the reactor and turbine section to produce the high temperature dry steam for the steam turbine; a steam turbine recuperator preheats water fed to the gas turbine exhaust heat exchanger; steam is made from part of the flue gas condensate produced by the condensing mode heat exchanger and injected into the solid fuel core for gas generation; the remaining combustion gases and flue gas condensate are cleaned and CO2 captured. The solid fuel ash stream is kept separated from the gas stream and disposed. I can not provide a decent cost for this system or subsystems at this time but it would compete with existing IGCC systems.

I fully understand this sounds grandioses, especially for a new reactor not even demonstrated yet. There are risks or unknowns such as how clean can the produced gas be made, mercury removal? Will the fuel nozzle plug? Can SOx formation be avoided? Can a turbine be made with ceramic blades to withstand harsh acidic gas and small amount of ash conditions? I do not know what the questions are for making the gas outer tube wall a cathode for a fuel cell. Will the gas nozzle create too much pressure to allow oxygen to pass through the cathode? Maybe the reactor is only good for gasifying solid fuels and integrated with a typical IGCC system.

All new technologies that have possibilities to contribute to the end goal of the FutureGen program should be allowed to be demonstrated. I believe that is the reason for restructuring the FutureGen program, to allow the widest range of possibilities.

Thank you for your time.

Robert Boucher
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PO Box 985
Bonner, MT 59823

Location of project - I am alone at this time. I am currently researching existing successful companies to partner with.

• Name, Point of Contact, Telephone Number, Mailing Address, E-Mail Address.

Bureau of Economic Geology, Dr Ian Duncan.
512-471-5117, ian.duncan@beg.utexas.edu

• Location of project **Texas**

• Narrative description of project that includes the status of project development and the technical and financial qualifications of the project team to conduct the project. **NA**

• Discussion of the company's ability to meet or exceed the time frame set forth in the above schedule. **NA**

• Estimated amount of DOE contribution (in percentage and/or dollars) that would be required for the company to pursue the project with IGCC-CCS technology. **NA**

• Any technological, financial, or legal issues or barriers that DOE should be made aware of that limit the effectiveness or feasibility of DOE's restructured approach to FutureGen.

Demonstrate in the United States commercial integrated operation of a gasification-based, coal conversion system with CO_2 capture and storage,

Comment: Why not a coal and pet-coke blend? Why not a post combustion capture project as well as gasification based?

- *Demonstrate approximately 90 percent CO_2 capture and storage on one nominal 300 MW train with annual requirements of one million metric tons in a saline aquifer, and*

> 99 percent sulfur removal
< 0.05 lb/million Btu NOx emissions
< 0.005 lb/million Btu particulate matter emissions
> 90 percent mercury removal;

Comment: These specifications are over prescriptive for a commercial project. What if the commercial project planned to capture 50% of the CO2? Why a 300 MW train?

- Help establish standardized technologies and protocols for deployment of IGCC –CCS, including CO_2 monitoring, mitigation and verification;

Comment: Why select winning technology as IGCC, other technologies such as supercritical coal with post-combustion capture may be more likely to be commercial?

- Demonstrate the practical reality of IGCC with CCS coal-based electric power plants operated with different coal types and at different U.S. locations; and

Comment: Again why select winning technology as IGCC, other technologies such as supercritical coal with post-combustion capture may be more likely to be commercial?

- Other information or concerns that would assist DOE in implementing the revised FutureGen.

Several projects under consideration in Texas do not meet the DOE requirement for Revised FutureGen but could achieve the objective of demonstrating commercially viable carbon capture and storage.

Mr. Miles - My comments are specific to the objective stated in DOE's announcement that units meet the following emission limits:

> 99 percent sulfur removal

< 0 05 lb/million Btu NOx emissions

< 0.005 lb/million Btu particulate matter emissions

> 90 percent mercury removal;

One of the purposes of the FutureGen project was to utilize new technologies, including those that are not proven in operation, to meet the original FutureGen emission rates. The IGCC units under development at this time cannot take the chance of having emission control systems, or other parts of the IGCC plant, that are for "testing" or "R&D" purposes. They must work. Therefore, the IGCC units going forward at this time plan to use what is referred to as Best Available Control Technology (BACT)

Please see the attached table, which shows the emission limits listed either in final permits or in permit applications for IGCC units in development at this time. All emission limits are on the basis of heat input to the gasifier, so that they can be compared to the stated FutureGen emission rates. While DOE's notice refers to "over 30 IGCC power plants" in development, the fact remains that the most likely projects to go forward at this time are those that have completed sufficient engineering to meet the detailed requirements for an air permit application. This requires preliminary engineering, site layouts, major gasification and combined cycle equipment selection, development of start-up and shut down procedures and detailed emission inventories The table shows the units in the U.S. that are at this level Note that several of these units have already been cancelled, leaving only a handful of IGCC units going forward, but certainly not "over 30 IGCC power plants"

I have highlighted in RED the emission rates in the table that do not meet the FutureGen objectives As the table shows, <u>none</u> of the proposed IGCC plants would be able to meet all of the FutureGen emission rates and requirements, even when using BACT. Therefore, none of the plants would meet the emission control objectives specified in DOE's announcement for the "Revised FutureGen" This seems counter-productive to DOE's intent for this program

I would suggest that DOE revise the emission rate requirements for the purposes of the "Revised FutureGen", so that the IGCC plants in development would be eligible for this program I would be pleased to work with DOE in developing a revised set of emission rates

Thank you,

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IGCC Project Developer	IGCC Project	Sulfur Removal, %	NOx Emissions, lb/MMBtu	Particulate Matter Emissions, lb/MMBtu	Mercury Removal, %
FutureGen Requirement	-	>99	<0.05	<0.005	>90
American Electric Power	Great Bend	>99	0.057	0.006 (Filterable)	>90
American Electric Power	Mountaineer	>99	0.057	0.006 (Filterable)	>90
Duke Energy Indiana	Edwardsport	>99	0.055	0.0117 (Total)	N/A
Energy Northwest	Pacific Mountain Energy Center *(IGCC portion cancelled)*	>99	0.0116	0.009 (Total)	≥90
Excelsior Energy	Mesaba	>99	0.055	0.009 (Total)	≥90
Southern Company and Orlando Utilities Commission	Orlando Gasification *(cancelled)*	>99	0.08	Opacity limit only	Value not provided
Tampa Electric Company	Polk #6 *(cancelled)*	>99	0.032	0.019 (Total)	≥90
Tenaska/ERORA	Christian County Generation (aka Taylorville Energy Center)	>99	0.0246	0.0065 (Filterable) and 0.016 (Total)	95
Tenaska/ERORA	Cash Creek Generation	>99	0.024	0.0062 (Filterable) and 0.0157 (Total)	95
Tondu Corp.	Nueces *(cancelled)*	>99	0.018	0.0062 (Total)	90

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Keith R Miles,
U S. Department of Energy,
National Energy Technology Laboratory,
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March 3, 2008

Re: Comments on Revised FutureGen

Dear Mr. Miles,

This letter constitutes the response of Christian County Generation, L.L.C. to the Request for Information on the Department of Energy's Plan to Restructure FutureGen (the RFI).

Responses to the information requests will be in the order that such information is listed in the RFI.

1. Name, Point of Contact, Telephone Number, Mailing Address, E-Mail Address:

Barton D. Ford
Vice President, Business Development
Tenaska, Inc.
1701 E. Lamar Blvd., Suite 100
Arlington, Texas 76006
(817) 462 1033
bford@tnsk.com

2. Location of Project:

Christian County, Illinois, slightly to the north and east of the City of Taylorville

3. Narrative description of project that includes the status of project development and the technical and financial qualifications of the project team to conduct the project

A. Description of Project

The Taylorville Energy Center (the TEC or the Project) is comprised of a bituminous coal-fueled Integrated Gasification Combined Cycle (IGCC) facility with a maximum continuous rating of 773 MW gross/630 MW net This Project is located on a 328.36 acre site in Christian County, IL adjacent to mines being developed and permitted by CAM-Illinois (CAM, a wholly-owned subsidiary of Central Appalachian Mining which is owned by Wexford Capital L.L.C.) and Peabody Energy (Peabody). The TEC is scheduled to enter commercial operation in 2013

More specifically, the TEC is comprised of:

- an Air Separation Unit ("ASU"),
- two (2) GE radiant gasifiers,
- two (2) gas cooling and Selexol® acid gas removal trains,
- carbon beds for mercury removal, and
- a GE 7FB combined-cycle power block.

The power block includes two (2) GE 7FB (MS7001FB) combustion turbines, two (2) Heat Recovery Steam Generators (HRSG), two (2) Selective Catalytic Reduction ("SCR") installations and a GE D-11 steam turbine

Significant ancillary IGCC systems include material handling/storage systems (coal, sulfur, slag, and consumables), a cooling tower, electric switchyard, natural gas metering/regulation station, water receipt and treatment facilities, a thermal oxidizer, a flare, an auxiliary boiler, fire protection equipment and control room/warehouse facilities.

B. Financing and Ownership Structure

The TEC is owned by Christian County Generation, L.L.C (CCG). The membership interests of CCG are currently owned 50% by MDL Holding Company, L.L.C., a Louisville, KY-based, privately-owned company focused on greenfield generation development and 50% by Tenaska Taylorville, LLC (together with its affiliates, "Tenaska") an Omaha, NE-based international power development company and energy marketer with expertise in power plant development, ownership and operation; natural gas and electric power marketing; and fuel procurement (*See*, Figure 1, below). Tenaska holds an option to acquire from MDL at financial closing the remaining 50% membership interests currently held by MDL

Financing and Ownership Structure

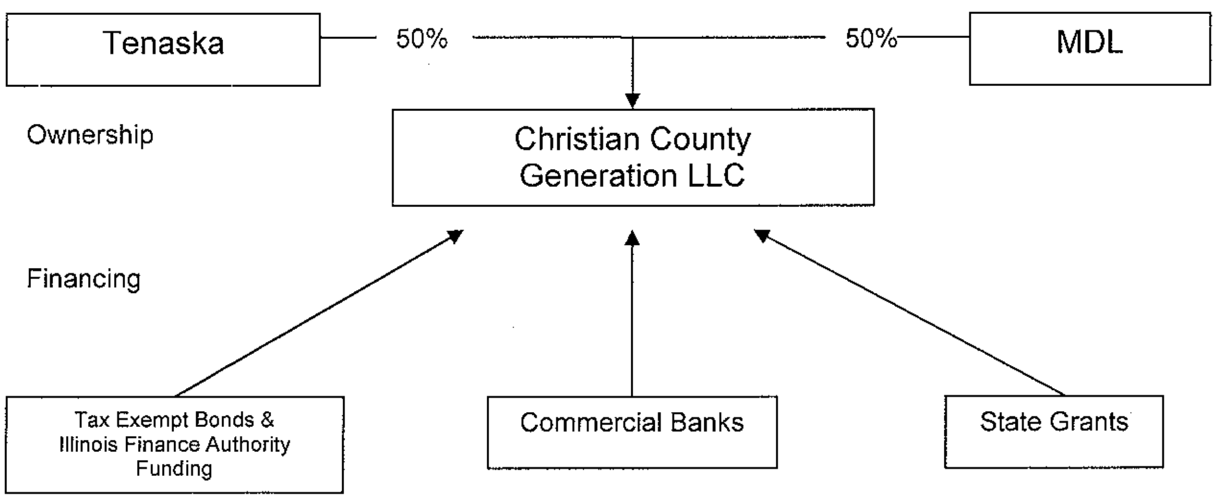

Figure 1: **Financing and Ownership Structure**

The funds necessary to construct the TEC will come from four sources.

- The equity participants, Tenaska, MDL, and potentially others, who will fund a significant portion of the total required funds (up to 45%)
- The State of Illinois, through the proceeds of moral obligation bonds issued under the "Illinois Resource Development and Energy Security Act."
- Financial institutions, either in the form of loans from commercial banks or from the proceeds of a capital markets debt issuance.
- Various state (and potentially federal) governmental grants in aid of construction and incentives

C. Describe the main parties to the project, including background, ownership and related experience

Christian County Generation, L.L.C.
CCG is a sole purpose entity that was formed to own the TEC.

Tenaska
Tenaska is a group of privately held companies with over 20 years of power plant development and energy marketing experience. In 2006, Forbes magazine ranked the company 26th among the top 100 privately held companies in the United States

Tenaska has developed and constructed approximately 9,000 megawatts (MW) of generation representing more than $7.7 billion in financing and capital investment

Unlike most other independent power developers, Tenaska has maintained a strict discipline of incurring debt only through non-recourse debt at the project level. Accordingly, Tenaska is debt free This strong financial position provides assurance to Tenaska's counterparties that the organization will remain financially stable and strong

Figure 2 is a map representing the breadth of Tenaska's development efforts and ownership interests.

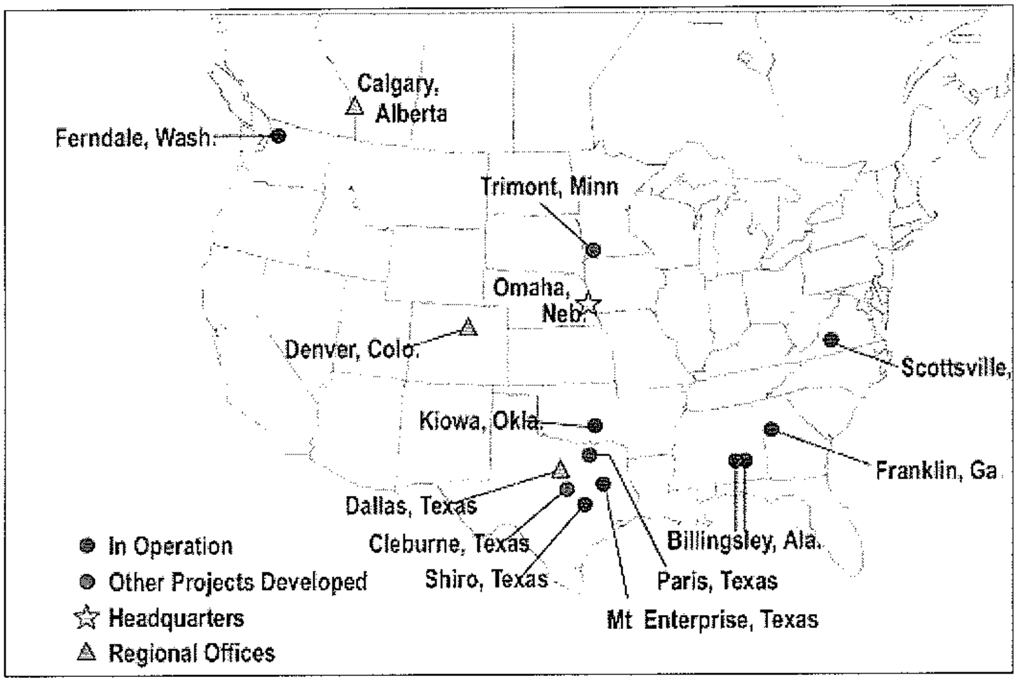

Figure 2: **Tenaska Developments and Offices**

Tenaska employees have experience in all aspects of large-scale generating project development, including combined and simple cycle natural gas facilities, pulverized coal, fluidized-bed, waste coal and lignite facilities. Tenaska employees have experience in gas and coal plant siting and permitting; engineering design and optimization; financing; construction contracting and management; fuel procurement and handling; commissioning; and operations and maintenance.

Tenaska Marketing Ventures, a Tenaska affiliate is among the top 10 daily marketers in the North American natural gas market, selling or managing more than 1.86 trillion cubic feet of natural gas in 2007. This volume is equivalent to approximately eight percent (8%) of total U.S. natural gas consumption. Tenaska also has a power marketing affiliate, Tenaska Power Services, that develops custom power supply solutions. It operates a 24-hour trading floor dealing primarily with sales of physical electric power, totaling more than 15,615 gigawatt-hours of electricity sales in 2007.

Tenaska is headquartered in Omaha, Nebraska. Regional offices are in Arlington, Texas; Denver, Colorado; and Calgary, Alberta, Canada

MDL Holding Company, L.L.C.

MDL Holding Company, L.L.C. (MDL) is a Louisville, KY-based, privately-owned company focused on greenfield generation development

MDL's principals have been active in the electric generation sector since 1975 and have worked together since 1990. The principals have significant experience in both the electric generation and finance (project and corporate) sectors. They have successfully developed or sold electric generation projects totaling 6,100 MW and representing in excess of $5.0 billion in investment including:

- 10 coal plants (6 totaling 900 MW in operation and 4 totaling 2,200 MW in development) located in Alabama, Illinois, Kentucky, North Carolina, Tennessee and Virginia.
- 13 natural gas plants (4 totaling 1,200 MW in operation; 2 totaling 1,100 MW in development; and 8 totaling 3,900 sold).

- 4 wind plants (120 MW operating)

Tenaska and MDL, through CCG, have assembled a world-class Project team comprised of the leading IGCC technology provider (GE Energy), the most experienced gasification operator (Eastman Chemical) and a leading engineering firm (Burns & McDonnell) to design and operate the TEC

CCG has executed agreements with Eastman Gasification Services Company (EGSC) that provide for EGSC participation in design review and operations/maintenance activities

CCG has retained Burns & McDonnell to perform balance-of-plant engineering and provide other owner's engineer services

State of Illinois
The Illinois Department of Commerce and Economic Opportunity is a strong advocate of the TEC, providing $2.50 million in grant funding to support the development and commercialization of the TEC.

The Illinois Clean Coal Review Board is also a strong advocate of the TEC granting $3.25 million in funding to support the development and commercialization of the TEC.

D. Current Project Status and Schedule to Beginning of Construction

The Project is being developed and is scheduled to enter commercial operation during the first half of 2013. Status of critical project development milestones is as follows:

Technology:	Christian County Generation acquired a license for the G.E gasification technology in 2005
Air Permit:	The final PSD Air Permit was issued by the Illinois EPA in June of 2007 The Environmental Appeals Board dismissed the only petition for review of the air permit during January 2008.
Land	CCG holds options on the Project site, which will continue to be used for agriculture until onsite construction work begins.
Interconnections:	Interconnection requests were filed with both MISO and PJM in 2006. Both MISO and PJM completed feasibility studies in the first half of 2007. System Impact Study Agreements with MISO and PJM were signed in March and April, respectively, of 2007.
Water Supply:	The Project has a Memorandum of Understanding for the supply of grey water and the treatment of wastewater with the Sanitary District of Decatur (SDD) which has a treatment facility located 28 miles to the north and east of the Project site. In November of 2006, SDD secured Illinois legislation to confirm its right to serve customers outside of its territory
Coal:	The Project will procure coal competitively, either from one of two development phase mines located adjacent to the project site or from other coal mines within economic transport distance

Power Offtake:	The Project's supporters are working on legislation (the Clean Coal Portfolio Requirement) that will require retail electric suppliers in Illinois to purchase clean coal energy from the plant under long-term contracts. A version of this legislation passed the Illinois Senate unanimously last year but did not reach the floor of the House for a vote. Tenaska is now working with the House leadership and expects that such legislation will pass during the current session, which ends in May.
FEED Study:	G.E. and Burns & McDonnell have completed a pre-FEED study and certain discrete parts of the FEED study, particularly with respect to fuel characteristics. The balance of the FEED will be completed once the Clean Coal Portfolio Requirement above is passed.
EPC Agreement:	We have had detailed discussions with an EPC contractor regarding commercial terms, but will not execute an EPC Agreement until the passage of the Clean Coal Portfolio Requirement and the conclusion of the FEED study.
Financing:	CCG has secured preliminary approval from the Illinois Finance Authority for $325 Million of tax exempt bond financing for solid waste disposal facilities and $150 million of other state financing. The remainder of the financing will be obtained in the commercial bank market, with the active financing phase beginning once the Clean Coal Portfolio Requirement becomes law.

4. Discussion of CCG's ability to meet or exceed the DOE's schedule for Restructured FutureGen.

CCG is currently ahead of the DOE's schedule, which would be a concern for our Project in participating in the revised FutureGen funding as currently envisioned. We hope to begin our detailed FEED study within a few months, after the Clean Coal Portfolio Requirement is enacted. If we will not learn until year-end whether the Taylorville Energy Center is selected for funding under the new FutureGen program, we will not know whether the FEED should design for 90% capture on one gasification train in accordance with the DOE's requirement for this program. We would need to undertake additional review to determine the feasibility of changing the FEED scope to incorporate 90% capture on a single train once it has been under way for several months. Assuming that CCG is selected, the National Environmental Policy Act (NEPA) review process may also result in a delay in our schedule unless we are able to take advantage to some extent of the environmental review for the Mattoon site and/or the Tuscola site, which are 50 to 60 miles to the east of the Taylorville Project site. In addition, perhaps only an Environmental Assessment and not an EIS would be required for DOE funding of CCS for the Taylorville Project, based on the view that the base project is going forward without DOE funding and the incremental CCS project would have no significant impact.

5. Estimated amount of DOE contribution (in percentage and/or dollars) that would be required for CCG to pursue the project with IGCC-CCS technology.

Our current high level estimate of capital costs for 90% single train capture and deep well aquifer injection at the site is $265 million to $425 million. This estimate includes interest during construction and other "soft costs". There would also be significant additional operating or performance costs in the form of lost output, reduced efficiency and increased operations and maintenance costs.

Under the Clean Coal Portfolio Requirement, the cost of capturing carbon will be absorbed by Illinois electric consumers, so ultimately it is a question for Illinois' elected leaders to determine as a policy matter how much of a rate increase Illinois electric consumers should absorb in order to provide for carbon capture. We anticipate that prior to applying for funding under the Revised FutureGen program, we would solicit input from Illinois' leaders on the amount of the grant that would be necessary in order for CCG to participate.

6. Any technological, financial, or legal issues or barriers that DOE should be made aware of that limit the effectiveness or feasibility of DOE's restructured approach to FutureGen.

In the absence of a specific statutory exception, DOE grants constitute taxable income to the recipient This was not an issue when the recipient of DOE funding was to have been a not for profit corporation, but it will be an issue in the funding of commercial projects. In order to preserve the full amount of any potential funding to pay for the capital cost of capture and sequestration, it would be desirable for DOE to pursue a legislative exemption with Congress

Another possibility for avoiding the imposition of taxes on the grant amount would be to create a project structure in which an entity other than the commercial IGCC project would own the equipment paid for with the grant and simply use this equipment to separate out the CO2 for capture as a public service Further study would be necessary to evaluate this approach since the equipment would be an integral part of the facility, but based on limited discussion with our tax advisors we believe it should be achievable

7. Other information or concerns that would assist DOE in implementing the revised FutureGen.

1. The estimated capital cost of capturing and sequestering approximately 20% of total plant (not just one gasification train) CO2 through second stage Selexol without a water shift are $150 million to $250 million, with significantly lower operating costs than for 90% capture on a single train approach. Also, a significant advantage of this capture option is that the capture equipment can be bypassed with no significant loss of efficiency at the plant in the event that the sequestration equipment is not in operation. That is not the case for capture at higher levels. The plant's efficiency would be permanently degraded with the design and installation of equipment for 90% capture on a single train, regardless of whether the plant is actually capturing and sequestering 20% capture would provide a substantial stream of CO2 (0.88 million tons per year at 85% plant availability) for injection testing DOE funding for the 20% capture option would be highly attractive if the program could be flexible enough to accommodate this option.

Also, we could begin our FEED study with this option incorporated and drop it if CCG is not selected at the end of the year, with much less disruption to the FEED study process than if we were to add 90% capture on one train after the FEED study had started. We ask that DOE consider funding 20% capture for at least one project that is ready to move forward into its FEED study during 2008, and that the selection of this project be accelerated rather than waiting until the end of this year.

2 We believe there may be opportunities in the future to sell CO2 to operators of a CO2 pipeline that would be built to transport CO2 from the Midwest south to the Gulf Coast states for use in enhanced oil recovery. In order to maximize the potential for such sales, it would be optimal to limit the required demonstration period during which at least one million tons must be sequestered to the shortest period of time that is necessary to demonstrate geologic sequestration.

Please feel free to contact me if you have questions or would like to discuss any of the information provided.

Very truly yours,

CHRISTIAN COUNTY GENERATION, L.L.C.
By: Tenaska Taylorville, LLC, Managing Member
By Tenaska, Inc., Its Manager

By: Barton D. Ford
Vice President, Business Development

Dear Mr. Miles:

I am a 59 year old economic development consultant and government project manager. I have been involved in the implementation of the "new energy economy" since 1979. In 1980-1983 I was a financial consultant associated with a major wall street underwriter closing "deals" as large as $100 Million In 1984, I was licensed in Calif. as a general building contractor and I have been involved in large RE projects (300 + acres) and numerous EIS processes. In 1987-1989 I was the Project Manager for over 100 school districts in L.A. & Orange Counties, Ca. for AHERA (The EPA Asbestos-in-Schools Program). I have also co-managed major retail construction projects (3-acre buildings) for "big-box-retailers.

In November 2007, I proposed to Colorado Governor Bill Ritter, the construction of a 3,000 MW (Three-Thousand MW) "GREEN-COAL" power plant on the Western Slope of Colorado. [Note: Five 600 MW-power trains in one facility]. On January 23, 2008 I received a letter form Governor Ritter in which the Governor agreed with the concept of constructing a 3-gigawatt IGCC-CCS power plant on the Western Slope. Be cognizant, the Governor of Colorado is amiable to building a 3 gigawatt IGCC-CCS power plant in Colorado.

After reading Secretary Bodman's surprise announcement of the restructured FutureGen Project, (multiple-sites) I made a "Time is of the Essence" proposal to four Western Slope-Colorado Local Governments. I proposed to the cities of Grand Junction, Fruita and Palisade and the County of Mesa they organize into a Colorado state authorized "Electric Power Authority" I proposed their non-profit corporation set-up for economic development; Grand Junction Economic Partnership, Inc. submit a response to the FutureGen March 3, 2008 RFI. I proposed that these four local Colorado governments place their name into competition for a FutureGen "Host-Community" with funding for CCS in 2010.

Because of the March 3, 2008 time frame, I am not sure if I was able to lobby political support in time for the four local Colorado governments to act on the RFI.

All that said, the following recommendations are made most respectively to President George W. Bush and Secretary Samuel W. Bodman and to you:

(1) To expedite the economics necessary for a cost-effective implementation of the President's Clean Coal Power Program, I suggest Secretary Bodman ask the President to introduce federal legislation whereby all "Clean-Coal Electricity" is classified as "GREEN-POWER". Here is where I coined the phrase: "GREEN-COAL". "What is good for the goose............" When all of the greenhouse gas emissions are sequestered it is only equitable, "Clean-Coal" is able to compete in the market place on an equal footing with the renewable energy as found in the Green Power legislation Therefore, this legislation, once the law of the land, will greatly expedite the new electric energy sources this country needs. To reiterate, I politely suggest to the President he personally introduce legislation that will give "Clean-Coal Electricity" the exact same market

advantages as "Green Power" : AKA "GREEN-COAL"

(2) I also suggest to Secretary Bodman that the FutureGen Project requirements for CCS be expanded to also include sequestering of CO2 in depleted natural gas wells. A major reason I am attempting to build the 3-gigawatt "GREEN-COAL" power plant on the Western Slope of Colorado is because the area is abundant in depleted natural gas wells Therefore, in funding beginning 2010, please consider me out here on the Western Slope of Colorado and allow for other sequestering methods instead of requiring saline geological formations

(3) I also suggest to the President and Secretary that we remember a man named Henry J Kaiser: Based upon the exorbitant costs estimates for the construction of the IGCC power plants, and; to make "GREEN-COAL" affordable for the American consumer, the price to construct an IGCC power plant must be significantly reduced. As you know, the American steel industry has evolved and is now quite capable of constructing, on a limited production run basis, most of the major components is an IGCC power plant. Especially when each steel plant would specialize in one-to-three components of an IGCC facility. These individual components could be manufactured at these new small steel manufacturing plants in America and transported and assembled at the "GREEN-COAL" site.

With Henry J Kaiser and his "Liberty Ships" in mind; I suggest CCPI money be used to commission the development of detailed engineering plans for a "state-of-the-art" "boiler plate" 300 MW IGCC (air&oxygen) & a 600 MW IGCC (air&oxygen) power train(s). <u>These plans would be the industry standard.</u> The use of the "Boiler Plate" detailed engineering plans, could then be granted to new 'GREEN-COAL' power developers and the "boiler plate" plans could be "cookie-cutter" throughout the United States.

Furthermore, the "boiler plate" plans could be made readily available by the DoE for a minimal charge, to the small steel plant operators. These steel mills could then set-up their production runs for manufacturing individual components of the IGCC power plants.

These American steel mills could eventually sell their IGCC components to overseas electric power developers and thus create American jobs that pay a livable-wage.

Thank you for your work, God Bless America.

Signed:

Carl L. Mc Williams, Project Manager
Colorado Secretary of State # 20081091925
65120 Old Chipeta Trail
Montrose, Colorado 81401

Monday, March 3, 2008

Comments submitted to the Department of Energy by the Coal Utilization Research Council (CURC) in response to a Request for Information (RFI) issued by the DOE

Comments submitted by:
Ben Yamagata
Executive Director
Coal Utilization Research Council (CURC)
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Washington, D C.
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bny@vnf.com

INTRODUCTION:

These comments are submitted on behalf of the membership of the Coal Utilization Research Council (CURC) in response to the Department of Energy's request for information related to the Department's intent to restructure the FutureGen project. A list of CURC's membership is attached. These comments address the proposed structure and content of the Department's revised FutureGen program but should not be interpreted, by this submission, as supporting the intention to terminate the government's participation in the FutureGen project

The CURC opposes the proposed action to terminate DOE support of the current FutureGen project. A copy of our letter to various Members of Congress in which we urge reconsideration of the proposed action is attached for your information. In this same communication CURC also noted its support of the Department's initiative to undertake a solicitation in which the DOE would provide funding for the incremental costs associated with installing and operating carbon capture and storage systems (CCS) on commercial-scale electric power generation facilities.

SUMMARY OF CURC'S CONCERNS ABOUT THE PROPOSED CCS PROGRAM:

(1) The amount of funding, $1.3 billion (in as-spent dollars), over a 14 year period (the scope and duration of the proposed program) is not adequate to support "multiple" CCS projects;4
(2) The program should not be limited to the installation and operation of CCS on commercial-scale IGCC projects; rather, a separate but parallel program for commercial-scale combustion-based projects, including both advanced pulverized coal with carbon capture and oxycombustion technologies, should be established, as well;

(3) The requirement to capture 90% of CO_2 and store at least one million tons per year of CO_2 into deep saline structures is overly restrictive; industry needs to obtain baseline data, demonstrated reliability and widespread confidence in CCS systems and these goals can be achieved more cost-effectively by requiring less aggressive percentages of capture;[1] and

(4) The lack of a regulatory structure to address the transport and storage (during the life of the project as well as longer term) of captured CO_2 along with a resolution to long term liability issues for selected power generation projects must be addressed, otherwise industry involvement is not likely to occur.

DISCUSSION OF SPECIFIC CONCERNS AND RECOMMENDATIONS:

1 FUNDING LEVEL AND DURATION OF PROPOSED PROGRAM

a. DESCRIPTION OF PROBLEM

On an annualized basis the level of funding proposed by the Department for this initiative is both inadequate and uncertain. Assuming an incremental capture and storage cost of \$50/ton CO_2[2], the \$156 million in funding requested for FY 2009 is sufficient to support no more than one to three projects for one year.[3] This assumes that the 300 MW project which would likely emit at least two million tons of CO_2 annually and be required to capture 90% of those emissions would choose to permanently store only one half of the CO_2 captured and "sell" the remainder to another entity for a beneficial use (e.g. enhanced oil recovery) or "release" such CO_2. If the project could sell the entire amount of captured CO_2 would it not do so? In which case, it would not be eligible for the program; alternatively if there were no opportunity to sell the CO_2 but the CO_2 must be captured, then the per ton of CO_2 benefit is even less given the fact that the government might compensate the project for only one half of the CO_2 captured

[1] The 90% capture requirement of total CO_2 emissions is more appropriately applied to the FutureGen project where technology demonstration is a principal goal rather than the type of commercial-scale projects contemplated by this proposed program Furthermore, even after detailed characterization of a sequestration site, there is no certainty that it will be suitable for long term sequestration. Certainty only comes after injection of significant amounts of CO_2 and thus confirmation of predictions about the storage site Projects need design flexibility to recover non-CCS operation if initial sequestration fails; thus, it is strongly encouraged that the program specifically recognize the possibility that long term sequestration may not be possible and specific allowance should be made for this contingency by insuring that a selected project sponsor will not be penalized and forfeit the DOE's financial support if long term storage proves unsuccessful

[2] DOE (see: Jared Ciferno, National energy Technology Laboratory "Existing Coal Power Plants and Climate Change: CO2 Retrofit Possibilities and Implications" January 24, 2008) and other studies have projected the incremental cost of CCS to be between \$40 and \$90 per ton

[3] As an example, a large-scale commercial power project with CCS will need to proceed through a sequence of stages Those and estimated costs (associated only with CCS) for a 300MW demonstration at ~2MM tons CO2/yr (90% capture) are:

Phase 1: Initial plant, pipeline feasibility study and preliminary sequestration site screening: \$2-3MM
Phase 2 Plant Front End Engineering Design (FEED) pipeline design and sequestration site detailed characterization: \$40-\$50MM
Phase 3: Detailed engineering and construction – plant pipeline, sequestration site facility and wells: \$250-\$350MM
Phase 4: CCS Commissioning, operation, monitoring for three (3) years: \$300MM
Total Cost/project: \$600MM-\$700MM

Thus the program funding of \$1 3B is adequate to support only 2 projects

Even if subsequent year appropriations were assured (a highly unlikely event given that appropriation requests are determined annually by Congress and also given the uncertainty beyond 2008 when a new President is in office and support of the program may be terminated) the amount of funding to be acquired annually, in our judgment, is totally inadequate The CURC has recommended a near term CO_2 program, one element of which is to support the installation and operation of carbon capture and storage on up to 9,000 megawatts of electric generation. The CURC program would provide a 30% investment tax credit for CCS equipment and a limited duration – up to ten years per project – production tax credit for CO_2 actually stored or otherwise used for beneficial purposes. The total estimated cost of the CURC program is $8.9 billion. This funding would support five to ten commercial scale projects which we judge to be the minimum number required to provide industry a degree of confidence that CCS is both feasible, reliable and can be made cost acceptable

b. RECOMMENDATION TO MODIFY THE PROPOSED PROGRAM

Assurances that the contemplated multi-year program will be funded at even the suggested $1.3 billion level are absolutely essential. And, unfortunately, the action taken by the DOE with respect to the FutureGen project is primary evidence of this real concern. In addition, the total amount of funding, as explained above, is not adequate. The DOE is encouraged to modify the program and propose a greatly expanded program, like that already proposed by CURC, which would grant tax incentives to qualifying CCS projects. At a minimum, the Department is encouraged to plan for and commit to a much larger initiative so that there is a program legacy tied to a much more robust industry and government partnership thereby giving both the Department of Energy and industry a basis for encouraging the next Administration to continue a large-scale, industry supported CCS implementation partnership

The RFI suggests that the DOE may provide support "up to" the incremental cost of a CCS project. The Department is encouraged to clarify the level of support that might be provided. Specifically, a final solicitation should clearly describe what portions of a CCS project (e.g. equipment associated with the capture of CO_2, pipeline transportation infrastructure, acquisition of storage rights, etc) are eligible for assistance. It is also assumed that the program is intended to cover the **entire** cost of the CCS portion of the project given the fact that the industry participant is willing to add the CCS component to its commercial-scale power generation facility If this understanding is not correct then the Department needs to explain what is intended. Finally, are annual operating costs of CCS operation for a minimum period of time included in a covered project?

2. ELIGIBILITY OF POWER GENERATION PROJECTS TO PARTICIPATE IN THE CCS PROGRAM:

a DESCRIPTION OF PROBLEM

The proposed program would be limited to the installation of CCS technology on IGCC units. The goal of the program should be to encourage the application of carbon capture and storage to electricity generation units and not to a single form of electricity generation.

The CURC strongly encourages the Department to expand eligibility to include combustion based systems. This should include post-combustion CCS systems that utilize flue gas cleanup technologies as well as more advanced concepts like oxycombustion. It is imperative that any program like the one being proposed by the Department seek to insure that all power generation options be incentivized. In this way, the electric utility sector will continue to have a number of options available for the generation of electricity and the capture and storage of CO_2

Should eligibility be expanded to include combustion-based units then it is also important that the unit size and percent capture criteria be modified, as well. The 300 gross megawatt per unit plant power train is not appropriate for a combustion-based unit.[4] The unit size of pulverized coal units vary widely and if the goal of the proposed program is to provide incentives for commercial scale projects then some other indicia besides megawatts per unit plant power train needs to be employed. In addition, CO_2 capture at this early stage of CCS development will involve capturing the CO_2 from a slipstream of the flue gases and the criteria that 90% of total CO_2 emissions from the unit be captured is also not appropriate.

b. RECOMMENDATION TO MODIFY THE PROPOSED PROGRAM

CCS projects utilizing combustion technology (i.e. flue gas scrubbing or oxygen-fired combustion technology) should be made specifically eligible for the proposed program. It is recommended, however, that there be a separate, parallel program established for CCS projects utilizing combustion technology. The criteria for CCS projects on gasification-based systems versus combustion-based systems are significantly different and trying to integrate into one program eligibility for two different technology paths is likely to cause confusion and controversy.

Second, the megawatt size criteria and the percent of CO_2 capture criteria must be modified to account for the varying unit sizes of commercially-installed coal combustion systems. In addition, early CO_2 capture systems installed on combustionbased units will be applied to portions of the flue gas stream and the 90% capture requirement on the entire flue gas stream is not appropriate. Combustion systems utilizing CO_2 capture systems (oxycombustion or scrubbers), should be validated at 75% to 90% capture efficiency and approximately one million metric tons per year of CO_2 captured. This goal would be realized at a single plant (oxycombustion) or a

[4] It is assumed that the reference to 300 MW with respect to an IGCC is gross, not net, capacity. The program should clearly state that parasitic power used for CO_2 compression, etc., impacts on the gasifier or gasification train due to elevation or rank of coal used in the project are factors that will not negatively impact the calculation of the 300 MW size

single commercial scale train (i.e scrubber) operating on a slipstream of the total flue gas

3. REQUIREMENT TO CAPTURE 90% OF CO_2 AND STORE 1 MILLION TONS ANNUALLY

a DESCRIPTION OF THE PROBLEM

Recent studies[5] have concluded that the costs to capture 90% of CO_2 from an IGCC rise dramatically once more than 65% is captured On combustion systems, capture (oxycombustion or scrubbers), costs appear to be minimized near 85% capture, either from the entire plant (oxycombustion) or a single train (scrubbers).[6 7]

Requiring 90% capture will dramatically increase the costs to the government (if the DOE provides financing for the incremental cost of the CCS system) and could dissuade participation by industry where the risk – and costs – will be judged too great. While the 90% requirement is an appropriate goal for the FutureGen project given the emphasis upon technology demonstration and maturation, nothing is gained by requiring a generating unit that is planned and constructed to provide competitive electric power to meet a 90% criterion when the goal should be to gain commercial experience by capturing some portion of the CO_2 At this stage of CCS technology development there is no compelling reason to require a commercial-sized power plant to assume any added risk, let alone increased costs, of a 90% capture system.

The RFI specifically states: " .the revised approach will place emphasis on gaining early commercial experience validating clean coal technologies through multiple demonstrations of CCS technology in commercially-operated ... electric power plants." Given the immature state of experience in using capture technology integrated with an IGCC, for example, CURC believes it is much more prudent to simply encourage the installation of CCS technology on a unit that will be commercially-operated rather than dictate the level of capture. Industry should be free to determine what level of capture of CO_2 makes the greatest sense from both a cost and acceptable risk exposure perspective. Ultimately, as experience is gained and cost and reliability are demonstrated, it is assumed that the marketplace will demand and technology providers will supply the most cost effective and efficient

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[5] See: S Gadde, J White of WorleyParsons and R Herbanek, J Shah of ConocoPhillips: ' CO2 Capture: Impacts on IGCC Plant Performance in a High Elevation Application using Western Sub-Bituminous Coal" at Gasification Technologies Conference San Francisco October 15 – 17 2007

[6] See: Rao and Rubin, 2006 and DOE-NETL 401/120106

[7] Two issues drive concerns regarding 90% capture on the combustion based plant First pulverized coal power plants are built to customer needs and one size does not fit all such needs Economies of scale for pulverized coal units has led to units well over 500 MW in the US and globally. Therefore, to build 90% first of kind CO2 capture into a new PC would require multiple modules of a post combustion capture technology essentially having to duplicate a demonstration multiple times on the same new power plant.. clearly an inefficient use of incentives Second, the quantity of CO2 produced by high capture on full plant output results in quantities of CO2 which will likely exceed the scale of first of kind sequestration demonstrations, making siting and integration of sequestration a much larger problem Oxyfiring does not face the same CO2 percent capture issues

For large generating units, e g over 400 MW capacity, 65% capture even if judged technically feasible, will recover well over 1 million tons per year of CO2 (a 1000 MW unit would capture 6-7 million TPY) The state of knowledge of storage technology in geologic formations is not sufficient at this point to address this volume of gas in a storage project The purpose of advancing storage technology would be better served by having more locations evaluated with less CO2 injection, as long as the injection quantity is substantial (e g, 500,000 TPY) systems. This demand likely will result in technology offerings capable of providing greater and greater percentages of CO_2 capture over time. At a minimum, if a level of capture is imposed in order to qualify for the program, then it is strongly urged that some minimum level of capture (not the maximum level of capture) be set against which the DOE might judge the best project(s) to be selected.

b RECOMMENDATION TO MODIFY THE PROPOSED PROGRAM

The owner/operators of commercial scale electric generation projects who are willing to install CCS systems onto their projects that will cost hundreds of millions, if not billions, of dollars, should not be restricted to the 90% capture requirement that is otherwise germane only to a technology demonstration project (i.e. FutureGen). The goal is the installation of CCS technology at commercial scale. The CURC recommends that no percentage requirement be prescribed in order to qualify for the program but if the DOE determines that a percent requirement is desirable then such requirement should constitute a minimum and be expressed in terms of a "goal" with an expressed statement that the Department will give added weight or preference if a proposer intends to achieve a greater percentage.

4. THE NEED FOR CERTAINTY WITH RESPECT TO LONG-TERM LIABILITY

a. DESCRIPTION OF THE PROBLEM

The Department makes no mention in describing the proposed program of the current lack of a regulatory structure that is required to transport, inject and permanently store the captured CO_2. This is a vitally important element of any forthcoming CCS project. The experience of the FutureGen project as well as the on-going projects within the regional sequestration partnerships is ample evidence of the complexity surrounding particularly the matters of injection, pore space ownership and short term and long term liability associated with CO_2 storage. These matters are being addressed through federal, state and local government's affirmative intervention. First-of-a-kind commercial-scale CCS projects, like those anticipated by the proposed program, will require similar assistance.

The establishment of a permanent regulatory regime has yet to be addressed. The absence of such a regulatory structure creates an unacceptable degree of risk and uncertainty which means that no action to undertake CCS projects will likely take place. In the interim, CCS projects implemented on commercial-scale power generation projects cannot await the years necessary to consider, debate and structure a permanent set of regulations and practices to address the storage of CO_2. Answers to questions about transporting CO_2, ownership of the storage reservoirs, injection of the CO_2 and liability issues attendant to the near term and then long term storage of the CO_2 must be addressed at the outset of the process when a CCS project is planned. The DOE, and various agencies of the federal government, have major roles to play in this process. More importantly, with respect to those projects that may participate in the program now under consideration, the DOE, and the federal government in general, must recognize that these early projects will require separate attention and unique consideration.

b RECOMMENDATION TO MODIFY THE PROPOSED PROGRAM

The FutureGen project is clear evidence of the enormous complexity facing any project seeking to install CCS technology and store CO_2 in a deep saline reservoir. It cannot be assumed, as the RFI suggests, that potential project sponsors will chose to site commercial-scale electric generation plants within reasonable proximity of the four sites considered by the FutureGen Industrial Alliance just to participate in this program. If as DOE suggests this program is being initiated to support industry activity now underway then the prospect of financial incentives alone will not be sufficient. To reduce the time required to identify potential storage sites, characterize such sites, obtain federal and state and local government commitments related to long-term liability issues, conduct the necessary NEPA reviews and environmental impact statements, etc. all of which has been accomplished by the FutureGen project and requiring five and more years to complete will require a substantial commitment by government. The DOE must acknowledge this challenge in the final solicitation for projects and define specifically how the government intends to assist in addressing these various issues.

With respect to projects that are selected to participate in this program it is strongly recommended that the federal government commit to assume long-term liability for monitoring, safety, etc of the stored CO_2. Without an assurance of this nature and in the absence of an existing regulatory regime that specifically addresses this issue it is not likely that owners/operators of commercial scale electricity projects will get involved. The CURC will be pleased to work with the DOE to suggest other specific actions that the Department or other federal agencies will need to take in order to address the challenges identified herein.

CONCLUSIONS:

In order to initiate the proposed program and insure industry participation it is strongly recommended that the DOE incorporate the recommendations made in this submittal. The need to develop carbon capture and storage technology if greenhouse gas regulation is enacted is not disputed. It will require the combined resources of industry and governments at all levels working in partnerships to accomplish rapid introduction of CCS technology. The CURC will be pleased to work with the Department in structuring this important program.

Duke Energy.
Generation Services

March 3, 2008

Department of Energy
RE: Restructured FutureGen Program, Request for Information
ATTN: Mr. Keith Miles

Dear Sir:

The Department of Energy has asked prospective participants to provide comments to the recently announced restructured FutureGen program. In conjunction with the Pennsylvania Department of Environmental Protection (PA DEP) and the Department of Conservation and Natural Resources (PA DCNR), Duke Energy Generation Services (DEGS), a wholly owned subsidiary of Duke Energy, is working to develop a sequestration network to permanently contain carbon dioxide in appropriate geologic formations such as deep saline aquifers underneath Pennsylvania Commonwealth property. DEGS agrees with the goal of supporting the development of carbon sequestration demonstrations at multiple sites and would like to provide an overview of an important new IGCC facility (the Fayette Gasification Project, hereinafter the "Project") which we are seeking to develop in Masontown, Pa. We believe that this Project should be considered a strong candidate for Department of Energy support under the proposed carbon sequestration program.

DEGS is a wholly owned subsidiary of Duke Energy, one of the nation's largest electric power companies in the United States which supplies and delivers energy to approximately 4 million U.S. customers. Duke Energy has nearly 37,000 megawatts of electric generating capacity in the Midwest and the Carolinas, of which DEGS operates and manages over 4,000 megawatts. Duke Energy has invested billions of dollars in emission reduction projects, and plans to invest approximately $4 billion in advanced coal generation over the next five years. Duke Energy has been involved in the successfully development, construction and operation of advanced energy projects including Integrated Gasification Combined Cycle (IGCC) since 1995.

Over the past several years there have been a large number of announcements of gasification projects proposed to produce electric power as well as SNG under both regulated and unregulated commercial constructs. Many IGCC projects have been materially delayed or otherwise canceled due to rising construction costs, inability to recovery capital through long term contracts and in many cases opposition to any coal fired generation that does not significantly reduce carbon dioxide emissions.

Another set of issues for development of IGCC with carbon sequestration is managing third party risks such as liability associated with an accidental release of carbon dioxide or impairment of adjacent property, and mineral rights when injecting and subsequently storing carbon dioxide underground. Typical risk management tools such as insurance coverage, indemnity protection or even legal precedence are not available to commercial scale projects utilizing carbon sequestration. To address these risks DEGS is working closely with the PA DEP and PA DCNR to introduce new legislation that would allow carbon dioxide to be captured, compressed and delivered to a carbon sequestration network owned by the Commonwealth of Pennsylvania. Attached please find a letter of support for the Project from Governor Rendell's office addressed directly to the Department of Energy

We believe that it is critical that a number of significant carbon capture and storage projects be developed and placed into operation on an accelerated schedule. This will establish the technical and commercial foundation for wider scale application in the future. Given the diversity of potential applications, which can include miscible and non-miscible carbon dioxide floods for enhanced oil recovery as well as geological sequestration, a wide range of applications are required. Further, geographic diversity is extremely important. For example, western Pennsylvania has the strategic potential to provide "de-carbonized" energy to eastern markets which have limited resources of conventional renewable energy and which do not have the suitable sub-surface geology to support carbon capture and storage. Further, Pennsylvania is endowed with significant coal resources and has access to these eastern energy markets through the established infrastructure of high-voltage electric transmission lines as well as high-pressure natural gas pipelines. Therefore, the development of commercial carbon capture and storage in western Pennsylvania is of strategic importance not only to the Commonwealth and its citizens and industry but to the United States

Given the need to accelerate commercial applications we believe that funding should be made available in a manner that does not trigger the National Environmental Policy Act. DEGS advocates the use of a carbon incentive payment per ton over a period of 20 years. Alternatively, providing a grant in aid of development and construction is possible. Finally, we believe that preference in the selection of projects be afforded to those initiatives that include a "public-private" partnership of the type described here, including State assumption of the liability associated with injected carbon.

DEGS applauds the Department of Energy for taking these steps to support a number of carbon sequestration initiatives at a time when the development of new coal fired generation, which is so critical to our nation's economy, is in jeopardy. We hope you will find our comments and facility description to be useful as you finalize your restructured FutureGen program. DEGS would welcome the opportunity to meet with Department of Energy and other FutureGen participants to exchange ideas on advanced coal generation and carbon sequestration technology and their importance to our economy. We look forward to participating in your program as it advances

Sincerely,

F. Reed Wills
Vice President, Business Development
Duke Energy Generation Services
225 Wilmington West Chester Pike
Chadds Ford, PA 19317
Office: 610.358.4790

cc: Wouter van Kempen, Michael Schwartz, Joseph Kelly

Response to DOE FutureGen Request for Information: Alternative Opportunity to Achieve FutureGen Project Objectives At Commercial Scale

Submitted by: Eastman Chemical Company
March 3, 2008

Contact Information: [redacted]

[redacted]

[redacted]

Location of Project: [redacted]

Narrative Description of Project:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

DOE should consider whether an IG project has to immediately or directly produce electric power from hydrogen. [redacted]

[redacted]

[redacted]

[redacted]

Technical and Financial Qualifications of the Project Team:

[redacted]

[redacted]

[redacted]

[redacted]

Ability to Meet or Exceed Restructured FutureGen Time Frame:

[redacted]

DOE Funding Required (very preliminary estimate):

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Technological, Financial, or Legal Issues or Barriers:

[redacted]

Hydrogen turbines of F-frame size or larger are not yet fully commercial and are not offered competitively at this time, although both GE Energy and Siemens claim they will offer them soon. [redacted]

[redacted]

Property rights, regulatory/permitting, and liability issues related to long-term CO2 storage in deep saline reservoirs from the proposed demonstration project must be clearly identified so that the associated financial risks can be assessed. Some of these issues are currently in the process of being addressed by federal agencies and/or the State of Texas.

Other Information or Concerns:

We firmly believe that industrial gasification (IG) projects offer the fastest and lowest-cost route for demonstrating commercial-scale carbon capture and storage and near zero-emission power generation. IG projects, by their inherent nature, require deep removal of contaminants such as sulfur and mercury because they tend to be poisons for chemical conversion catalysts used in such projects. IG projects also inherently require that almost any carbon dioxide formed during the process be separated out and captured as a concentrated stream (using well-proven technologies), and the cost of such carbon capture is built into the economics of the products being produced by the project. If hydrogen or ammonia are products of the IG project, full syngas shift capability will also have been built into the project design. Thus, the additional costs to capture and sequester carbon dioxide from such projects are the lowest of any coal or petcoke-based projects. [redacted]

Because IG projects, in general, provide products with higher value than electric power, they are more likely to be financed and built in today's challenging economic environment. We have seen numerous gasification and coal-based combustion projects deferred or cancelled in the past year due to the challenging economic environment and uncertain environmental regulation environment, but the gasification projects that have continued to move forward on a global basis are predominantly IG projects.

IG projects also provide opportunity for higher overall reliabilities and shared risks. [redacted]

Another advantage of IG projects is that they can use opportunistic domestic feedstocks, such as coal, petcoke, biomass, and secondary recycled materials. We believe that the DOE should not limit the restructured FutureGen project to just coal feedstocks, but should embrace a spectrum of domestically available feedstocks. The objective should be to reduce our dependence on imported feedstocks such as oil and natural gas and to utilize our abundance of a spectrum of domestic feedstocks, including utilizing byproducts of oil refining that reduce the need for further importing additional crude oil.

In this same context, the use of EOR applications for sequestration of CO_2 should also be encouraged by the restructured FutureGen project, because in addition to providing geologic storage opportunities for the CO_2, the additional enhanced oil production further reduces our need for imported oil and for new drilling (with its associated environmental concerns). [redacted]

[redacted]

[redacted]

[redacted]

DOE should also consider whether an IG project has to immediately or directly produce electric power from hydrogen. [redacted] The electric power generation from hydrogen can be decoupled and done as a subsequent or separate bolt-on test phase (Phase II), allowing the technologies of carbon sequestration and hydrogen turbines to each advance on their own pace. Another potential option would be to utilize substitute natural gas (SNG) production, coupled with carbon sequestration, and utilization of existing NGCC facilities (either attached directly or remotely via pipeline) as an allowable FutureGen-type project.

Summary of Opportunity to Accomplish FutureGen Objectives:

[redacted]

[redacted]

Given the importance of sequestration solutions to the future use of America's inexpensive and abundant coal and other feedstock reserves, Eastman believes that DOE's plans for FutureGen-type projects have merit. Openness to considering utilization of IG projects, and their associated feedstocks, for FutureGen-type projects could accelerate the overall demonstration timeline and reduce overall demonstration costs while improving the overall probability of success. That provides a win-win-win for American energy independence and also provides new opportunities for American jobs.

Response to DOE FutureGen Request for Information: Alternative Opportunity to Achieve FutureGen "Living Laboratory" RD&D Objectives

Submitted by: Eastman Chemical Company
March 3, 2008

Contact Information: [redacted]

[redacted]

Location of Project: [redacted]

Narrative Description of Project:

One of the objectives of the original FutureGen proposal that had great merit was the establishment of a "living laboratory" RD&D center for advanced gasification technologies. As the costs for the original FutureGen program skyrocketed, DOE was driven to consider a restructured FutureGen program that focused on multiple early commercial technology demonstrations and excluded the advanced RD&D Center concept. Although this approach should help accelerate current-generation advanced technologies for near zero-emission power generation and for carbon capture and sequestration (CCS), it does little to accelerate development and demonstration of next-generation advanced technologies One of the major concerns with current-generation gasification technologies are their high capital costs. RDD&D

of advanced next-generation technologies may help to significantly reduce capital and operating costs, improve overall efficiencies, and improve overall reliabilities. While it is extremely important to focus on successful near-term commercial demonstrations of clean energy production and CCS, the "living laboratory" aspect of the original FutureGen program should not be abandoned.

Eastman Chemical Company pioneered the first commercial application of coal gasification for production of chemicals in the U.S. in 1983 at our Kingsport, TN site. We will achieve 25 years of successful operation in June of this year. Eastman's operational performance during that 25-year time span has been exceptional, averaging over 98% on-stream availability since 1984. But Eastman has done more than pioneer coal gasification in the U.S. We have partnered with the DOE and others, and innovated on our own, to develop and demonstrate a number of advanced technologies and capabilities related to gasification [redacted]

[redacted]

[redacted]

Time Frame:

[redacted]

DOE Funding Required (very preliminary estimate):

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Technological, Financial or Legal Issues:

[redacted]

[redacted]

[redacted]

Other Information or Concerns:

[redacted]

[redacted]
Lindell Blair
949-798-7903
[redacted]
Irvine, CA 92612
[redacted]

Location: Illinois

Project Description

The IGCC project is in the early development phase, with potential sites in Southern, Illinois with access to water, coal, transmission and natural gas The goal of is to develop, own and operate a commercial scale IGCC that can demonstrate carbon capture and sequestration using Illinois Basin coal has evaluated IGCC with the following capture rates: 20-30 % , 50%, and 90% Estimated cost for 90 % capture is estimated to be 30-40 % of the total project cost Sequestration would be in-situ at the plant facility if geologic formations below the plant allow for the sequestration of CO_2 If not, CO_2 would be piped to the ISGS golden rectangle of the Mt Simon Sandstone formation is currently a partner in the MGCS partnership

has a corporate history in IGCC and understands the complexity of constructing and operating IGCC was a 50 % partner in the [redacted]3 Energy project in Sicily has experience in financing large, complex electric power projects such as [redacted] and the [redacted] portfolio is experienced in working with partners

Project Time Line

Because the project is early development and the time line for completion of Sequestration Partnership Phase III project is in 2016 time frame, it is most likely that the COD time set forth in the RFI will not be met

DOE share

It is estimated that the DOE share for CCS would be in the range of 30-40% of the project cost

Issues

1 *Scope of CCS* - Because of the integrated nature of the IGCC with CCS it may be difficult to separate the CCS portion of the project What is DOE's view of on the boundaries for CCS?

2 *Capture Rate* - Projects that capture less than 90% of CO2 emissions, but still meet the 1,000,000 ton injection rate should be eligible for support in DOE's restructured FutureGen program

3. *Eligible Costs* - DOE should pay for operating cost of capture and compression during the demonstration period, including parasitic load, chemicals and maintenance.

4 *"Single-Train" Funding* - How firm is DOE on single-train funding of CCS? Does single train mean the gas stream from a single gasifer designed to operate a 1 x1 CCGT power block? Given that most or all of the 30 or so IGCC projects mentioned in RIF are 2x1 designs, would DOE fund a lower capture rate system from a combined gas stream necessary to support 2 CCGT operations, if it meets the 1,000,000 million ton criteria?

5 *Liability Issues* - CO2 liability is an issue for project developers What is DOE's position on liability for carbon capture, transport and storage? Would DOE consider providing liability protection for projects selected? Edison Mission believes that the transport and storage functions could be separated from the capture project, but we would have concerns around impacts due to non-performance of those other functions These concerns may/can be addressed by appropriate contract language.

6 *Form of Award* - Will the award for CCS be lump sump or will it paid during the course of construction?

7 *Payback Provisions* - Will the payback provisions for CCS, be similar to those discussed in CCPI Round three public hearing of Nov 07? What will trigger the payback?

8 *Economic Viability* - Economic viability is still questionable even with DOE covering CCS cost What the developer is left with is a CCGT with a rather expensive fuel processing facility on the front end, this presses the issue of economic viability, because most markets do not support a stand-alone gas-fired CCGT

[redacted] appreciates the Department's inquiry here and would be pleased to provide additional information

[redacted]
Fred McCluskey, Kent Wanninger
[redacted]
312 583 6097, 312 583 6077
One Financial Place
440 S LaSalle
Ste 3500
Chicago, Illinois 60605

Location: Pennsylvania

[redacted] appreciates DOE's willingness to fund CCS under a restructured FutureGen. As the operator of a large coal portfolio, [redacted] believes that DOE should consider supporting deployment of post-combustion carbon capture as an integral part of a restructured FutureGen program The opportunity to help demonstrate CO2 capture technology that could be applied to the existing coal fleet is enormously important

Project Description

[redacted] proposes up to a 200 MW slipstream post-combustion carbon capture project at the
(located in Pennsylvania The station burns locally mined Pennsylvania bituminous coal. Several post-combustion technologies are under review. Based on our assessment it appears that ECO2 would be the technology of choice. Storage would be in-situ in the geologic formation below the station or nearby. [redacted] has completed an initial geologic site characterization and the results for in-situ storage looks encouraging

Project Time Line

Meeting the deadline in the RFI is tight but achievable based on our early assessment

DOE share

It is estimated that the DOE share for this post-combustion carbon capture and sequestration project would be in the approximately 200 million dollars

Issues

1 *CO2 Capture rate* - Projects achieving a capture rate of less than 90%, but still capable of meeting the 1,000,000 ton annual injection target should not be penalized in the final evaluation

2. *Eligible Costs* - DOE should be willing to help fund the operating cost of capture and compression during the demonstration period, including parasitic load, chemicals and maintenance

3. CO2 liability is an issue for project developers. Will DOE be providing liability protection with regard to carbon capture, transport and storage for projects accepted under the restructured FutureGen program? Would DOE consider a DOE sponsored CapCo that would stand behind the CO2 liability? Are their lessons that can be drawn from defense plant clean up operations re management of liability? Midwest Generation believes that the carbon transport and storage functions could be separated from the carbon capture project, but would have concerns around impacts due to non-performance of those functions. These concerns may be addressed by appropriate contract language

4. *Form of Award* - Will the award for CCS be lump sump or will it be paid during the course of construction?

5. *Payback* - Will the payback provisions for CCS, be similar to those discussed in CCPI Round three public hearing of Nov 07? What will trigger the payback?

We commend the Department for undertaking this inquiry and would be pleased to provide additional information on this project. If demonstrated at we believe this carbon capture technology could be used at a large number of existing coal plants located in similar geological basins

Eltron Research
& Development

Comments on the Department of Energy's Plan to Restructure FutureGen

March 3, 2008

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I. Recommendations for FutureGen and the proposed funding opportunity

Support slipstream access for developing CCS technologies.
DOE mandates and funding will be required for technology developers to prove their applications and compel industry adoption If all FuturGen plants are single train IGCC-CCS, there will be no opportunity for slip-stream testing. Therefore, funding opportunities need to be provided for testing on DOE funded plants such as Wilsonville or Eastman Chemical.

Support CCS technologies that are already beyond lab scale. Technology developers with solutions at readiness levels close to pilot demonstration require further funding support. Utilities and power providers will not invest in these technologies until the economics are proven on a pilot plant scale.

Include Eltron's Membrane System for Carbon Capture and Hydrogen Separation.
Techno-economic models indicate that Eltron's Membrane System will provide greater carbon capture at a lower cost of energy than conventional technologies for IGCC-CCS.

Include Warm Gas Cleaning.
Techno-economic models indicate warm gas cleaning improves carbon capture (up to 95%) and economics for IGCC-CCS systems using a membrane system for hydrogen separation.

II. Eltron's Membrane System for Carbon Capture & Hydrogen Separation

In partnership with the Department of Energy, Eltron Research & Development Inc. has been conducting a sustained multi-year development program for a membrane system that simultaneously captures carbon dioxide for storage and separates high-purity hydrogen from a water-gas shift feed stream Eltron's Membrane System for Carbon Capture and Hydrogen Separation enables economical and clean power generation from coal by providing improved carbon capture, greater thermal efficiencies and an incremental cost savings over conventional technologies.

Eltron's Membrane System for Carbon Capture and Hydrogen Separation is a critical component of an economically viable IGCC-CCS system.

Eltron's Membrane System for Carbon Capture and Hydrogen Separation enables 90-95% carbon capture and simultaneously produces essentially pure H_2 at a high flux. With or without hydrogen export, the Membrane System is ideal for coal-based IGCC applications requiring CCS. The system and membranes are designed to operate under a variety of conditions to allow flexible process design Specifically, Eltron's membranes have been operated at temperatures and pressures most conducive for integration with water-gas shift (WGS) reactors.

Benefits for IGCC-CCS:

- System enables 90-95% carbon capture.
- Separates and maintains carbon dioxide close to gasification pressure to minimize compression and energy costs for pipeline transportation and sequestration.
- Simultaneously produces a high pressure hydrogen/nitrogen stream for power generation from next-generation turbines.
- Process design is economic in multiple configurations; current models show up to $11/MWh cost of electricity savings over current technology.
- HHV efficiencies up to 6% higher than current technologies.
- Compatible with commercial technology for required levels of sulfur, NOx, mercury, and particulate removal

Other Benefits

- Effective with synthesis gas generated from any source including coal, petroleum coke, natural gas, or biomass.
- High hydrogen recoveries of over 90%.
- High hydrogen permeate pressures
- Essentially 100% pure hydrogen production as the membrane works by transporting dissociated hydrogen across the membrane material.

Process and economic modeling based upon observed membrane performance show that use of Eltron's Membrane System for separation of hydrogen and carbon dioxide in an IGCC-CCS plant provides an incremental improvement over currently available technologies such as solvent systems. The next phase of the development program will further advance our Membrane System performance yielding a stronger position over the alternatives

Further modeling with the integration of warm gas cleaning showed an even greater economic advantage as well as improved carbon capture – more than 95%. While Eltron's Membrane System does not depend upon warm gas cleaning, the combination of the two technologies would provide extremely attractive economic and environmental advantages for IGCC-CCS plants

III. Process and Economics: Eltron's Membrane System for IGCC-CCS

Eltron's high pressure, high temperature tolerant membrane system simultaneously captures carbon dioxide for storage and separates high-purity hydrogen from a water-gas shift feed stream. As described below, current modeling shows that Eltron's system in IGCC power plants has the potential to capture more carbon than current technologies and at a lower cost of electricity.

Process performance and economics have been evaluated in detail for IGCC carbon capture using 1) conventional technology, 2) Eltron's Membrane System, and 3) Eltron's

Membrane System with warm gas desulfurization. The assumptions used in the process modeling were based on the FutureGen targets and are summarized below.

Table 1. Process Modeling Assumptions.*

Plant Capacity	275 MW
Required Carbon Capture	90%
Required Sulfur Removal	99%
Required NOx Removal	≤ 0.05 lb/MMBTU NOx
Cost of Electricity	DOE Financial Model v3.0

**FutureGen: Integrated Hydrogen, Electric Power Production and Carbon Sequestration Research Initiative*, US DOE Office of Fossil Energy, March 2004

The basic configuration and processes of the plant include coal gasification to produce synthesis gas (syngas) followed by gas cleaning at or near-gasifier pressure, water-gas shift reactors to produce additional hydrogen and CO_2, then separation of hydrogen from CO_2. For each case, a flow diagram is presented below summarizing the process and showing where carbon is lost or captured throughout the process. As power-only cases, these flow diagrams assume power production from a 230 MW GE 7251FB turbine for power production

Economics (summary provided in Table 2) were compared against conventional technology, such as the Selexol process, for separating CO_2 from a hydrogen-rich syngas stream. 90% carbon capture was used as a basis Using hydrogen membranes vs. Selexol was not the only change between the comparison plants It was found that for the conventional technology, it was more economical to use the Selexol system for sulfur and CO_2 removal downstream of the water-gas shift reactors. Whereas sulfur removal with a COS hydrolysis reactor, followed by a lower-cost amine absorber upstream of water gas shift reactors, improved CO_2 capture efficiency when using a hydrogen membrane for separation of hydrogen and CO_2. Figure 1 shows IGCC-CCS based on currently available technology

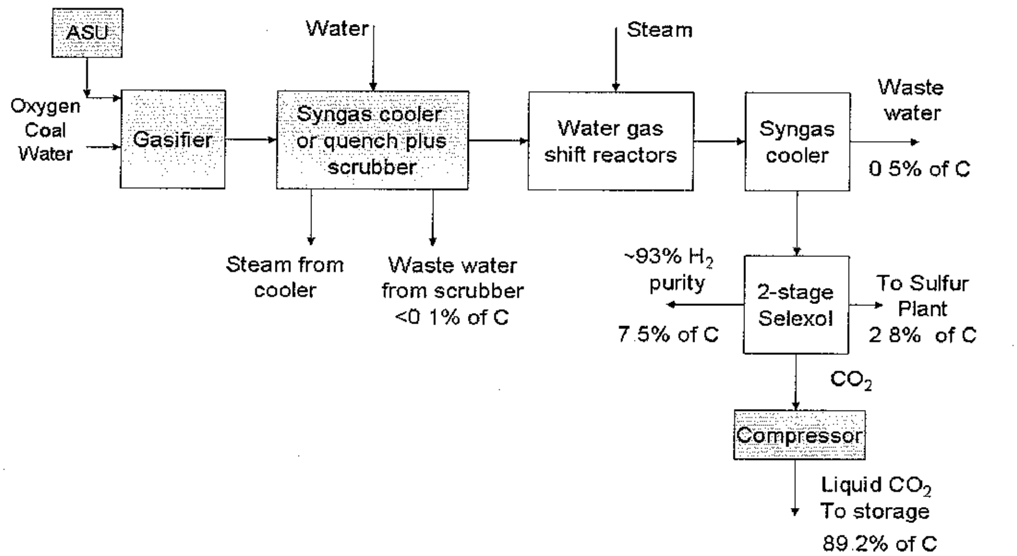

Figure 1. Flow diagram for pre-combustion power only case for CO_2 capture with current technology.

Current technology for pre-combustion carbon dioxide separation is limited by the facts that CO_2 is captured at low pressures and that the maximum carbon capture is only 90% of the total carbon. Eltron's approach to IGCC-CCS is a pre-combustion separation technology designed for integration with multiple gasifier types and hydrogen turbines under development by third parties. Eltron's technology is based on a separation membrane that separates hydrogen out of a high pressure water-gas shift feed stream, as shown in Figure 2.

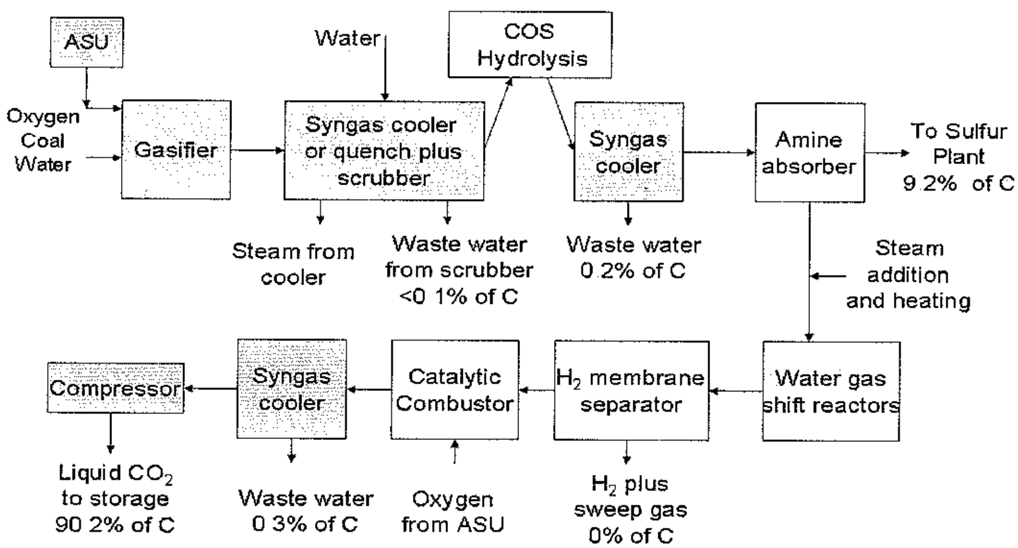

Figure 2. Flow diagram for pre-combustion power only case for CO_2 capture with Eltron membrane technology.

The raffinate steam can be easily knocked out; this stream from the membrane system is >95% pure CO_2 – after any remaining CO and H_2 are removed in a high pressure catalytic combustor (CATOX) unit. Therefore, Eltron's technology essentially takes a high pressure CO_2/H_2 stream and separates it into a high pressure CO_2 stream for sequestration and a high pressure H_2 stream for energy production. Figures 1 and 2 show that in both cases about 90% of the carbon is captured, which is required by DOE guidelines. Results from the process economic analysis show that an IGCC plant that uses an HTM in a power-only scenario is very competitive, on a COE (cost of electricity) basis, with plants that employ more traditional technology. Improvements were achieved over the conventional system by optimizing membrane staging and hydrogen recovery, as well as removing steam from the syngas upstream of the membrane.

The ability to separate and maintain CO_2 at high pressure will significantly reduce compression and energy costs for transportation and enable decoupling of power generation and carbon transport and storage.

Further improvement in thermal efficiency, economics, and percent carbon removal can be achieved by combining Eltron's membrane system with warm-gas desulfurization (rather than an amine absorber) for sulfur removal. Eltron is actively developing warm gas cleaning technology. Other approaches are also being developed at RTI. Figure 3 shows one possible flow diagram for integrating warm gas cleaning with Eltron's membrane for carbon capture.

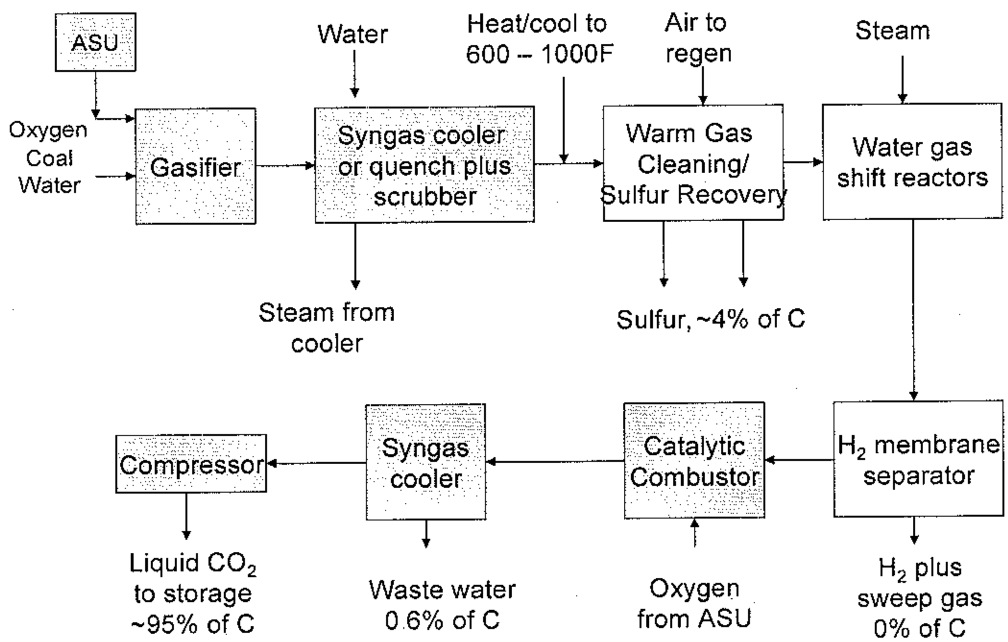

Figure 3. Flow diagram for pre-combustion power only case for CO_2 capture with warm gas desulfurization and Eltron membrane technology.

In this scenario Eltron found a further increase in HHV efficiency, a further decrease in COE, and a higher percent carbon capture

Table 2. IGCC-CCS Performance and Cost Comparisons

CO_2 Capture Method	None	Pre-combustion Selexol	Eltron WGCU & Membrane	Δ Selexol vs Eltron WGCU & Membrane
Coal Feed (tpd)	2,853	3,258	3,526	+268
Net Power (MW)	291	239	318	+79
HHV Efficiency	39 3%	27.4%	33.6%	+6.2%
% CO_2 Captured	0%	91.30%	95.30%	+4 00%
Cost of Electricity ($/MWh)	83.4	115.5	106	78.1*
Plant Cost ($/kW)	1,733	2,434	2,292	1,863*

*Cost applicable only to the incremental net power produced.

Eltron's Membrane System shows a clear advantage over conventional solvent systems.

Eltron has systematically improved our membrane system performance throughout the development program And we expect to continue making improvements. Multiple variables remain to be optimized that have the potential to improve system performance and lower costs. Variables such as membrane thickness and composition, membrane lifetime, gasifier choice, percent carbon capture, and process design are a few examples of system parameters that will be developed and tested in the first part of the proposed program.

IV. Technical and Financial Qualifications

Eltron is well positioned to advance the Membrane System to commercial readiness. Eltron has the required facilities, equipment, team members, and commercialization resources including relationships for collaboration and funding.

<u>Reactors and Other Equipment</u>
Eltron has five high pressure reactor systems dedicated to carbon dioxide, hydrogen membrane development Many of these reactors have unique capabilities that allow Eltron to test membranes under conditions that cannot be simulated anywhere else All five reactors are capable of testing membranes at temperatures up to 750°C and pressures

up to 1000 psig. Two reactors are designed for screening experiments. These reactors are capable of a hydrogen / helium mixed gas feed stream at pressures up to 750 psig. The third reactor allows Eltron to test multiple membrane configurations under a simulated water-gas shift feed stream (H_2, CO_2, CO, and H_2O). This scale-up reactor is capable of high flow rates at pressures up to 1000 psig. Membranes can be tested in a planar or tubular configuration. In addition, multiple membranes can be tested in series or in parallel. Finally, Eltron has two reactors that are used for lifetime testing under a full simulated water-gas shift feed stream. These reactors are intended to provide long-term membrane stability data by exposing membranes to expected IGCC operating conditions for up to 9000 hours

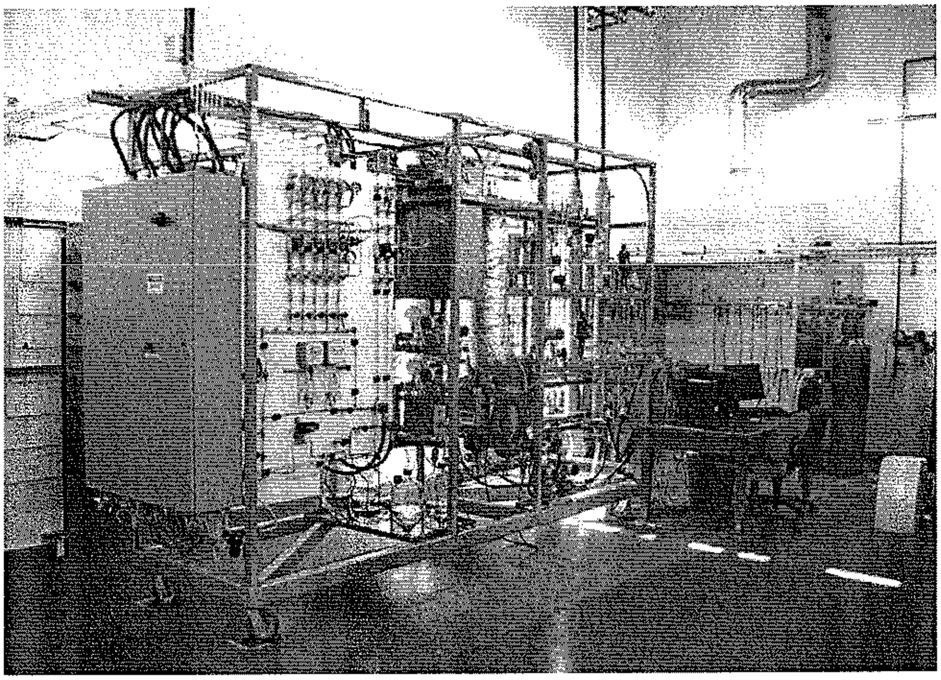

Figure 4. Eltron's lifetime reactor test skid.

In addition to Eltron's unique membrane testing reactors Eltron has extensive analytical capabilities for characterizing membranes before and after testing. Eltron has in-house X-ray diffraction, Scanning Electron Microscopy, and thermal analysis equipment.

<u>Team</u>

Mr. Douglas Jack, Vice President-Technology, is responsible for program management. Mr. Jack brings over 28 years of experience in technology development and commercial application of technology in the petroleum and chemical industries. Most recently he worked at ConocoPhillips as Manager of Major Program Development where he was responsible for identification and commercialization of new business opportunities for internal applications leveraging existing ConocoPhillips technologies or by adding new technologies to their portfolio by purchase, development or license.

Damon Waters, Business Development Manager, will develop the relationships necessary for commercial development and application. Damon has nine years of experience commercializing early stage technology though product development, intellectual property licensing and new venture creation. Prior to joining Eltron, Damon worked with universities in technology commercialization through seven new start-up companies and over 20 license agreements. In 1999 he co-founded a software company that raised $12 million in angel and venture capital and was acquired by a public company in 2002. Mr. Waters holds bachelor's degrees in environmental engineering and economics from Duke University, as well as a master's degree in engineering management from Duke.

Dr. Carl Evenson, Chief Scientist, will be responsible for supervising the technical development of Eltron's Membrane System. Dr. Evenson's responsibilities at Eltron include development of hydrogen membrane separation technology, synthesis of new lithium-ion battery cathode and anode materials, and development of coating technologies such as anodization and chemical vapor deposition. Dr. Evenson received a B.A. in Chemistry from Gustavus Adolphus College, and a Ph.D. in Inorganic Chemistry from Colorado State University.

Dr. David Anderson, Chief Engineer, will be responsible for supervising process engineering and modeling of Eltron's Membrane System. Dr. Anderson's responsibilities at Eltron include process engineering, integration, and economic evaluations for various technologies under development. Prior to joining Eltron, he worked in process research and development in the petroleum industry. He received a B.S. from the University of Colorado and a Ph.D. from the University of Houston in Chemical Engineering, and is a member of AIChE.

Dr. Richard Mackay, Research Fellow, will provide technical support to the project. Dr. Mackay's current responsibilities include the development of mixed ion and electron conducting ceramic materials used in oxygen separation processes, and research into the physical and chemical properties of these materials. His recent work has emphasized the optimization of reactors incorporating membranes made from these mixed conducting materials. Development of improved catalysts for these systems is pursued concurrently with the development of improved materials.

Dr. Michael Mundschau, Senior Principal Scientist, will provide technical support to the project. Dr. Mundschau studied chemistry at the University of Wisconsin-Milwaukee. His Ph.D. work at the Laboratory for Surface Studies was in catalysis and surface science. His work at Eltron has focused on developing catalysts for oxygen and hydrogen transport membranes. Dr. Mundschau is the author of over 65 scientific papers, and has presented his work as invited speaker at over 60 conferences and seminars around the world.

<u>Commercialization Resources</u>
Eltron intends to fund the next development phase with support from the Department of Energy and a strategic industry partner. Eltron is carefully yet aggressively establishing the appropriate industry relationship(s) to provide the following:

- Access to the entire marketplace and an interest to provide Eltron's Membrane System to all domestic projects.
- Resources to advance the technology through the pilot plant demonstration stage and to the marketplace.
- Complementary skills such as process engineering, sales and marketing.

Eltron has existing relationships with most of the top candidates for this role and is actively discussing potential deals with select parties.

V. Proposed Timeframe and DOE Contribution

Eltron has put together a plan for demonstration of this technology with a work plan to be implemented over the course of five years at a cost of $46 million. Table 3 summarizes the yearly project costs and expected cost-sharing between DOE and private industry.

Table 3. Budget Summary for the Proposed Expanded Work Plan

	FY 2009	FY 2010	FY 2011	FY2012	FY2013	TOTAL
DOE Contribution $	5 202,800	7,091,800	8 644,400	10,030,125	5,142,105	36 111,230
Industry Contribution $	1 300,700	1,772,950	2 161,100	3 343,375	1,714,035	10,292,160
Total Budget, $	6 503 500	8 864,750	10,805,500	13,373,500	6 856,140	46 403,390

Notes:

1) Stage Gate 1 prior to construction of PDU is scheduled to be evaluated at end 2Q FY10; total expenditure to that point will be $10 6 MM
2) Stage Gate 2 prior to construction of SEP (4 TPD) is scheduled to be evaluated at end 4Q FY11; total expenditure to that point will be $26.2 MM

The project will be managed using a stage gate process to ensure proper decisions are made at two key points in the program. Stage Gate 1 can only be passed if the membrane demonstrates performance that provides a clear economic advantage over alternative technologies when integrated into an IGCC plant. Flux and lifetime are the key parameters that must be met A second criterion for passing this first stage gate is that membrane manufacturability must be clearly outlined.

Stage Gate 2 occurs at the point where sufficient data has been collected in the Process Development Unit (PDU) to enable a paper design of the Sub-scale Engineering Prototype (SEP) Assuming that the economics and manufacturability of the membrane system still meet targets, the SEP will be constructed and operated to obtain the final engineering data needed for a commercial unit.

A full scale system will be ready for early-commercial demonstration in 2015

1. Name:

Energy Industries of Ohio
Point of Contact: Robert M. Purgert
216.533.1309
6100 Oak Tree Boulevard, Suite 200
Independence, OH 44131
purgert@energyinohio.org

Industry Consortium:

Alstom Power, Inc
Babcock & Wilcox Company
Riley Power, Inc.
Foster Wheeler Development Corporation
General Electric
Siemens Westinghouse
Alstom Power Turbines
Electric Power Research Institute

2. Location of Project: Ohio, Massachusetts, New Jersey, Connecticut, California, New York, Florida, Tennessee

3. Narrative:

COMPLETION OF PRE-COMPETITIVE TECHNICAL DEVELOPMENT OF ADVANCED ULTRA SUPERCRITICAL (A-USC) COAL-FIRED POWER PLANTS

The recent results from a highly successful DOE sponsored project to develop the materials technology needed for operation under advanced steam cycles have paved the way for building future combustion based pulverized coal power plants with higher efficiency and substantially reduced emission levels of greenhouse gases In an ongoing project, candidate alloys with the necessary high strength and corrosion resistance capable of operation at temperatures approaching 1400°F (Advanced UltraSuperCritical or A-USC) have been identified and techniques for welding and fabricating components of these alloys have been developed. Development of this technology is a major first step in the efficient utilization of coal as a fuel source and has rendered combustion based use of coal as an attractive option for power generation.

The use of coal for electrical generation poses a unique set of challenges however. On the one hand it is plentiful and available at low cost in much of the world, most notably in the United States, China, and India. Coal constitutes the source of fuel for a significant portion of the energy produced in these and other countries and offers relief from the stranglehold of foreign supplied fuels, especially oil and gas. On the other hand, traditional methods of coal combustion emit pollutants and CO_2 at high levels relative to other electric energy generation options. Improving the efficiency of the coal fired plants offers a significant path for using coal as the fuel and, at the same time, considerably reduces the amount of all effluents including CO_2.

In the long run, it is not logical to collect CO_2 emissions from anything other than the most efficient energy conversion plants available. Capturing and storing byproducts from unnecessary consumption of fuel is a very expensive exercise that only consumes more resources and power, and releases more heat into the environment (an often overlooked effect on the heating of our surroundings). In a recent study sponsored by DOE and Ohio Coal Development Office or OCDO, it has been estimated that the specific coal consumption and CO_2 generation can be reduced by 25 to 30% from the typical subcritical steam plant operating in the USA by utilizing higher steam conditions. Such a plant has also been found to be economical due to the fuel savings and the reduction of balance-of-plant requirements. Further, the 25-30% smaller CO_2 capture system, transport infrastructure, and storage requirements result directly from the more efficient use of fuel resources.

This position paper builds upon the materials technology that has been developed in the course of the highly successful DOE/OCDO project to enable construction of Advanced Ultrasupercritical plants (A-USC) and outlines further tasks needed to carry the technology to a "near commercialization" stage. The consortium of all the U.S. boiler and turbine manufacturers are of the opinion that the technology can be carried to a "Near Commercial " stage with a final phase or last lap to the current project.

The U.S. project consortium is comprised of all the U S. boiler and turbine manufacturers working under the technical direction of the Electric Power Research Institute (EPRI) and with assistance of the Oak Ridge National Laboratories (ORNL) and other laboratories and Universities. Overall Program Management and Administration has been the responsibility of the prime contractor, Energy Industries of Ohio (EIO), with major funding coming from the Department of Energy, the State of Ohio, and cost share contributions from the industrial participants. The research being conducted is defined as pre-competitive as it adds to the general knowledge of the strength properties, resistance to oxidation and corrosion, fabricability and weldability, availability of protective coatings, and development of appropriate general design information and procedures for a select number of best candidate alloys.

While a range of post-combustion capture technologies under development could be applied to an A-USC plant, the continuing project is also focused on developing the materials expertise to permit integration of oxy-combustion process in the boiler. As planned in most IGCC applications, oxy-combustion means the separation of nitrogen from the combustion air, so that nearly pure oxygen is used for combustion, and so that the otherwise and more expensive process of separating nitrogen from CO_2 in the flue gas is avoided. When integrated into the boiler and overall plant design, oxy-combustion is considered to result in a much simpler CO_2 purification process compared to other approaches, including those proposed for IGCC application, and other current emissions control systems may be rendered unnecessary. Oxy-combustion presents some special challenges to the boiler materials technology, and in this carbon capture solution, the boiler and materials design are integral parts of the overall CO_2 capture system.

The efficiency of conventional fossil powered plants is a strong function of the steam temperature and pressure. Research aimed at increasing these conditions to as high as 1400°F (760°C) and 5000 psi (35 Mpa) has been pursued worldwide. The U.S program has resulted in significant advances in the main enabling technology needed to achieve these goals which is the development of high temperature alloys and fabrication practices that will be necessary to withstand the conditions presented by the higher temperature boiler and turbine environment for these Advanced Ultra Supercritical (A-USC) plants.

The current program entering its Phase II will leave only a limited number of additional tasks that would complete the efforts that may be undertaken as a consortium. This final phase or last lap (and subject of this paper) would result in the project being completed by the end of 2014. The collaborative and public funded effort will have thus been completed providing U.S. industry with the ability to demonstrate a 760°C plant by the late 20 "teens".

This is very important as Europe is acknowledged as having a lead in advancing the technology of A-USC and has active plans for commercialization of a full-size utility power plant by approximately the year 2015, though it will be a 700°C whereas the U.S project is aimed at 760°C. Though the European Union (EU) initiated a comprehensive program several years prior to the U S effort, and, has maintained the lead, the U.S. consortium has considerably closed the gap and with a "last lap" effort, could conceivably leap frog the Europeans to a higher efficiency type system in a relatively short time.

The Europeans have employed a systematic plan to commercialization, which is classic in approach and consistent with the U S program to date and recommended in the follow-on work described below. In parallel with the DOE/OCDO study, EPRI has also taken the initiative to recommend to their member public utilities a plan for deployment of A-USC plant technology that is a phased approach known as UltraGen. The work recommended here is consistent with the EPRI objectives within the pre-competitive development phase, and dovetails well into the longer range plans that the UltraGen initiative recommends.

These "final lap" activities necessary to lead to U.S. commercialization are briefly described below

DESCRIPTION OF APPROACH: The path to technological development consists of three remaining general task areas. The first consists of continuing research in various fields of metallurgical, fabrication, and design technology, building on the knowledge gained in the earlier phases of research for both the boiler and turbine programs. Research tasks will be distributed between the industrial consortium members, as well as ORNL, EPRI, and supporting laboratories and Universities. This task is being undertaken now as the Phase II of the current project.

The second main task involves the design, fabrication, and operation of a component test facility within an existing, operating coal-fired boiler that will allow testing of candidate boiler materials under prototypic A-USC boiler conditions for a period of approximately three years. This component test module (CTM) will involve boiler segments representing various portions of the boiler, including the lower furnace and superheat circuitry, including collecting steam headers, associated piping, and valves. As an offshoot of this work, building the module will allow exploration of the ability of the existing world-wide material suppliers to satisfy the needs of this emerging technology. Components of the module will be instrumented to obtain data that can be compared to design predictive models and thus verify accuracy of these analytical tools. After a suitable period of time in test, the module components will be removed and examined using both non-destructive and destructive methods. In this manner, it will be possible to directly assess the effects of long time exposure on these advanced engineered components to typical A-USC environments and conditions. This will provide an important benchmark for the laboratory based testing to be conducted over the course of the program.

The third task involves the design and procurement of prototypically sized turbine parts from the advanced material candidates. Turbine blades, rotors, and casings will need to be made of materials new to that industry, as well as to the supplying material melters, forgers, and heat treaters.

KEY GOALS: The envisioned research and development activities will validate the technical and economic feasibility of the A-USC power plant, complete pre-competitive data generation, and lay the groundwork for activity to commercialize this technology. The objectives are:

- Select best candidate alloys needed for the A-USC plant. Supply critical information regarding each material's mechanical strength including long-term stability, physical properties, resistance to oxidation and corrosion effects and thermal fatigue, fabricability and weldability, as well as canvas the best candidate protective coatings available, and determine appropriate generalized design procedures and strategies to assure best long term service life

- Consider effects of increased amounts of CO_2 in the boiler operating environment, that will result from accomplishment of CO_2 capture and storage, on materials of construction.

- Determine the ability of the world-wide material supply network to supply forgings, piping, and casting, of the necessary composition, quality, size, quantity, and cost to support A-USC plant needs for both the boiler and turbine islands.

- Demonstrate successful, long-term operation of prototypically sized boiler components in an operating coal-fired boiler modified to develop A-USC operating conditions of temperature and operating stress.

- Demonstrate the practical reality of Advanced Ultra Supercritical coal-based electric power plants, with carbon capture, that can be operated with different coal types.

- Produce the technical and economic data needed for these types of plants to gain acceptance by the coal, electricity, and banking industries, and the public at large, as a cost-effective means for producing electric power in a carbon constrained world.

4. Company Ability

Each of the consortium members are proven industrial organizations providing power generation systems currently from either the boiler or turbine perspective. The include:

Alstom Power
Foster Wheeler
Babcock Riley Power
Babcock & Wilcox
General Electric
Siemens Westinghouse

Electric Power Research Institute
Energy Industries of Ohio

5. DOE contribution. DOE's cost share has not be established for this final phase or last lap of the program. Currently DOE is providing approximately 65% of the project costs. The remaining portion has been provided from the industry consortium and the State of Ohio

PROJECT COSTS: Costs for the "final lap" tasks are estimated as $40 M. This amount is for covering general Tasks 2 and 3 outlined above as the Component Test Module (CTM) design, material procurement, fabrication, erection, and other cooperative efforts with the hosting public utility, instrumentation and data gathering, operating for a period of three years, metallurgical analysis and assessment of the components and materials, and design verification versus the actual data and performance measured and observed covering both boiler and turbine components, and also addressing forging and casting operations, and extensive quality control parameters.

SCHEDULE: The program is designed to support a competitive commercialization of the A-USC technology by 2015. In order to achieve this, the earliest phases of CTM design needs to be started by CY2009 in order to allow for detailed design and material procurement (1 1/2 year span), fabrication and erection in an operating boiler (one year span), and a three year operating window. Material procurement is planned to begin no later than CY2010.

6. Issues

An industry consortium, particularly one comprised of competitors, has a number of issues that require careful and deliberate acknowledgement. First, and probably most important, are anti-trust considerations and the need to insure that all applicable state and federal "restraint of trade" issues are adequately addressed.

This issue was confronted through the development of a working "Memorandum of Understanding" amongst the team members. Lines of demarcation and limits of information sharing, Intellectual Property protection, and patent rights issues had to be drawn. One area of potential conflict was the provision in federal contracting where the non-profit organizations (EPRI) had different patent rights than those afforded to the for profit organizations by the Department of Energy.

Besides addressing anti-trust and intellectual property issues, a means of governance for the project was required to be put into place. This was accomplished by the formation of Technical Steering Committee (TSC) charged with technical aspects of the project and a Project Management Oversight Committee (PMOC) comprised of senior level managers from each of the consortium members.

The duties of the TSC were limited to overseeing technical aspects of the project and conduct monthly teleconferences and quarterly meetings. The PMOC has needed to meet only rarely to resolve managerial issues that were outside the scope of the TSC charter such as developing communication strategies for working with organizations such as the Coal Utilization Research Consortium (CURC) and only a few other issues.

Other issues that required to be resolved were that for a multi-task project, the Team Leaders in many cases were from one organization requiring other consortium members to be in a somewhat subservient role Given that all team members assumed Leadership for at least one Task, there has not been any difficulty with this issue.

Another issue was funding. The Federal budget runs from October 1 through September 30 whereas the State of Ohio's is from July 1 through June 30 and many of the consortium members operate on a calendar year. This meant developing budgets for each of the funding sources and then because of legislative issues precluding passing the budgets in a timely fashion, often times having a considerable time lag of funding actually being released to the project, careful attention to allocations and spending rates has permitted EIO to manage through these situations.

Finally, a defined communication protocol aided the project immensely. Given that the consortium consist of 6 different industrial members, the Electric Power Research Institute and collaboration with Oak Ridge and Albany National Laboratories, Energy Industries of Ohio was required to maintain close monitoring of technical and business progress of each of the members.

7. Other information

This working consortium of the power generation industry is the first time the power generation industry has worked together on pre-competitive technology. The only other consortium of this magnitude has been the US Car program where Detroit's Big Three have joined for other pre-competitive technologies The model undertaken for the USC project has proven to be very successful and has worked very well. The possibility for seeing the program through the pre-competitive stages and regaining international leadership for Advanced UltraSuperCrititcal systems by U S. industrial firms is an opportunity that should be considered very heavily by the reviewers given the cost and need for strategies to address CO2 constraints.

COMMENTS ON REVISED FUTUREGEN

Bryan Hannegan, Vice President, Environment and Generation
The Electric Power Research Institute (EPRI)
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The Electric Power Research Institute, Inc , a tax exempt, non-profit, 501(c)(3) collaborative research and development organization with principal locations in Palo Alto, California, Charlotte, North Carolina, and Knoxville, Tennessee ("EPRI") appreciates the opportunity to provide input and comments on the Department of Energy's plan to restructure FutureGen.

EPRI's comments address the following:

- Clarifying questions on the restructured FutureGen plan.
- Design changes and cost estimates for the addition of CO_2 Capture and Storage (CCS) to a single train of a two-train Integrated Gasification Combined Cycle (IGCC) plant not previously designed for CCS.
- Accelerating Research Development and Demonstration (RD&D) on Advanced Coal Technologies with CO_2 Capture and Storage—Investment and Time Requirements.
- Comments on whether the revised FutureGen approach should allow for advanced coal technology systems, other than IGCC, which also would meet the performance requirements.

Clarifying Questions on the DOE RFI

According to the RFI, DOE will contribute not more than the incremental cost associated with CCS technology for the single power train.

The additional costs for adding CCS to an IGCC plant include:

- Capital costs to cover the process modifications necessary for 90% CO_2 capture
- Operations and maintenance (O&M) costs for the additional units
- Lost revenue from power sales due to the additional auxiliary power use for capture and CO_2 compression
- Capital costs for CO_2 pipeline and CO_2 injection for sequestration
- Possible capital and O&M if pipeline length requires recompression
- O&M costs for pipeline transportation, sequestration and monitoring.

Clarifying Questions:

1. Is it the intent of DOE to cover a) the extra capital costs b) the extra O&M costs c) the lost power cost d) the pipeline, monitoring and sequestration costs (including pipeline compression power costs)?
2. Over what period of operation (how many years) will DOE cover the CCS costs?
3. Some IGCC projects are under consideration for the co-production of other chemicals or fuels (Synthetic Natural Gas, Methanol, Coal to Liquids, etc – often referred to as polygeneration). Will DOE consider the support of CCS at such polygeneration projects under this restructured initiative?

Design Changes for the Addition of CCS to a single train of a two-train IGCC plant not previously designed for CCS.

IGCC Design changes for 90% CO_2 Capture. The main changes in design for capture are the addition of shift reactors and a CO_2 removal process.

The shift reaction $CO + H_2O = CO_2 + H_2$ is exothermic. This results in a reduction in the chemical energy in the syngas so that it now is insufficient to fully load the gas turbine. Additional coal would need to be processed to provide enough syngas to fully load the gas turbine The percentage increase will depend on the gasification process. Dry coal-fed processes will require a somewhat greater increase than slurry-fed processes because the CO content of the syngas is higher. (The estimated increased coal feed in the referenced papers are in the range 2-9%) The following changes would be required if the plant is to be able to fully load the gas turbine:

- More coal handling and feed system capacity
- A larger Air Separation Unit (ASU) to provide the additional oxygen (perhaps an additional Main Air Compressor (MAC)) See Note 1.
- A larger gasifier to handle more coal and oxygen
- Larger gas cleanup and piping to handle the increased syngas flow

An alternative is to accept the lower output from the originally sized plant This would mean an additional loss of net power of approximately the same 2-9%, depending on the technology.

The addition of the shift reactor increases the volume of the dry gas flow to the Acid Gas Removal (AGR) H_2S removal system by 40-60%, depending on the gasification process. If the original design used a physical solvent (e.g. Selexol) for H_2S removal, then either a new parallel absorber column will be needed to accommodate the additional flow of syngas from the shift reactors or a completely new absorber designed for the full flow must be added In all cases a new CO_2 absorber/stripper system must be added.

The addition of 90% capture to a train will require the following changes:

- Replacement of COS/HCN hydrolysis reactor with 2 stages of sour shift reaction
- Additions to syngas cooling train for the shift reactors
- Additions to, or replacements of, the AGR used for H_2S removal to accommodate the increased dry syngas flow
- Addition of a new absorber/stripper system to recover CO_2 as a separate by-product
- Upgrade of the demineralizer water treatment and storage system
- Addition of intermediate pressure steam for water-gas shift reaction (in some cases)
- Modifications to the gas turbine combustion system to accommodate the combustion of hydrogen-rich gas, possibly including more addition of diluent nitrogen or moisture (steam)
- Heat Recovery Steam Generator Low Pressure superheater modifications
- Addition of CO_2 drying and compression to 2000 psig (138 barg)
- Possible adjustments to the CO_2 composition (e.g. H_2S content) depending on the pipeline quality requirements.

Note 1 For many of the designs without capture, ~30-40% of the air supply for the ASU is extracted from the gas turbine compressor. If the turbine supplier indicates no air can be extracted when firing hydrogen in the gas turbine, another air compressor would be needed to fully supply the ASU when capture is added.

Additional Costs for adding CCS to IGCC. The additional costs for adding CCS to an IGCC plant include:

- Capital costs to cover the process modifications listed above necessary for 90% CO_2 capture
- Operations and maintenance (O&M) costs for the additional listed units
- Lost revenue from power sales due to the additional auxiliary power usage for capture and CO_2 compression
- Capital costs for CO_2 pipeline and CO_2 injection for sequestration
- Possible capital and O&M if pipeline length requires recompression
- O&M costs for pipeline transportation, sequestration and monitoring

References: The following publicly available references can be used to obtain more information describing the processes and design changes involved in the addition of CCS to IGCC designs and estimates of the additional costs:

DOE/NETL- 2007/1281 "Cost and Performance Baseline for Fossil Energy Plants" Revision 1, August 2007.

"Preliminary Economics of SCPC & IGCC with CO_2 Capture & Storage." N. Holt (EPRI) presented at the 2nd IGCC & XtL Conference, Freiberg, Saxony, Germany May 9 -10, 2007.

"Phased Construction of IGCC Plants for CO_2 Capture- Effect of Pre-Investment" December 2003. EPRI Report # 1004537. Available from EPRI public domain website and DOE/NETL Fossil Energy website.

"Potential for Improvement in Gasification Combined Cycle Power Generation with CO_2 Capture" by Foster Wheeler for the IEA GHG program April 2003. Available from the IEA GHG website.

Cost estimates for the Addition of CCS to a single train of a two-train IGCC plant

Duke Energy's Edwardsport IGCC Plant will be about 750 MW *gross* or 375 *gross* MW/train 90% capture on one train yields approximately1.6 million tons per year CO_2 for sequestration and reduces *net* MW output by about 40 MW from 630 to 590 MW.

The extra capital for capture on one train is an estimated $80-100 million but may be more if it is a retrofit.

Extra O&M is estimated at approximately $1.5/MWh or $6.3 million/year. For 10 years the additional O&M would be an estimated $63 million.

Replacing the 40 MW lost power at $65/MWh equals $18.2 million per year. For 10 years the power replacement cost would be $182 million

Pipeline costs obviously depend on location. If 100 miles of pipeline are required to get the CO_2 to the storage site, at a cost of $1 million/mile the pipeline cost would be $100 million. Actual pipeline costs will vary with terrain, throughput, etc

Both DOE NETL and EPRI have estimated the incremental cost of adding CCS to an IGCC plant at about 30 $/MWh. These estimates are based on 20- and 30-year plant lives, respectively. If the capital is to be paid off in a shorter time, these estimates will rise. The Department of Energy is interested in funding multiple demonstrations of CCS technology at a commercial scale of at least 300 gross MW per unit plant power train. 300 MW at $30/MWh at 80% CF for 10 years results in a cost of $630 million. If it is the intent to pay for one project for its life of 20 years, the cost would be $1.26 billion and DOE's $1.3 billion would fund only one project. Therefore, the intended funding period for DOE support is a key consideration

Accelerating RD&D on Advanced Coal Technologies with CO_2 Capture and Storage

Through the development and deployment of advanced coal plants with integrated CO_2 capture and storage (CCS) technologies, coal power can become part of the solution to satisfying both our energy needs and our global climate change concerns. However, a sustained RD&D program at heightened levels of investment and the resolution of legal and regulatory unknowns for long-term geologic CO_2 storage will be required to achieve the promise of advanced coal with CCS technologies. Through research obtained in EPRI's *CoalFleet for Tomorrow®* program—a research collaborative comprising more than 60 organizations from five continents representing U.S. utilities, international power generators, equipment suppliers, government research organizations, coal and oil companies, and a railroad—EPRI sees crucial roles for both industry and governments worldwide in aggressively pursuing collaborative RD&D over the next 20-plus years to create a full portfolio of commercially self-sustaining, competitive advanced coal power generation and CCS technologies

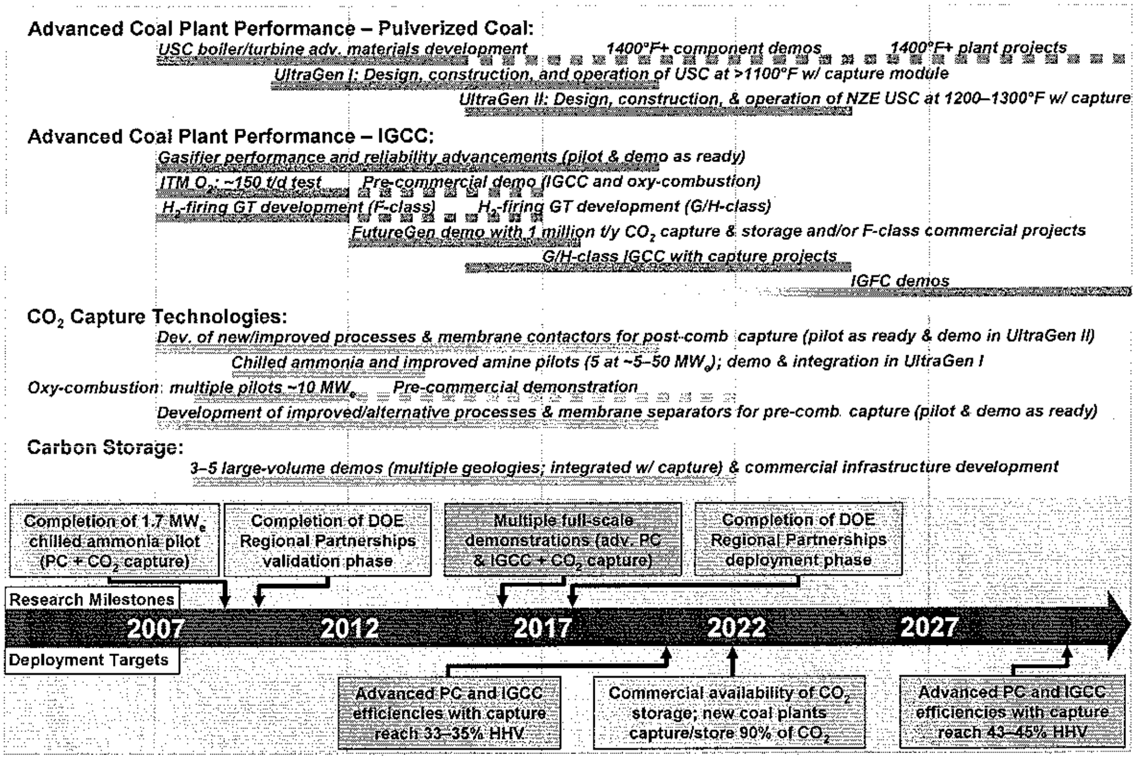
The portfolio aspect of advanced coal with integrated CCS technologies must be emphasized because no single advanced coal technology (or any generating technology) has clear-cut economic advantages across the range of U.S. applications. The best strategy for meeting future electricity needs while addressing climate change concerns and minimizing economic disruption lies in developing a *full portfolio* of technologies from which power producers (and their regulators) can choose the option best suited to local conditions and preferences, and provide power at the lowest cost to the customer. Toward this end, four major technology efforts related to CO_2 emissions reduction from coal-based power systems must be undertaken:

1. Increased efficiency and reliability of integrated gasification combined cycle (IGCC) power plants
2. Increased thermodynamic efficiency of pulverized-coal (PC) power plants
3. Improved technologies for capture of CO_2 from coal combustion- and gasification-based power plants
4. Reliable, acceptable technologies for long-term storage of captured CO_2.

Identification of mechanisms to share RD&D financial and technical risks and to address legal and regulatory uncertainties must take place as well

In short, a comprehensive recognition of all the factors needed to hasten deployment of competitive, commercial advanced coal and integrated CO_2 capture and storage technologies—and implementation of realistic, pragmatic plans to overcome barriers—is the key to supplying affordable, environmentally responsible energy in a carbon-constrained world.

Figure 1 is an illustration from EPRI's report entitled, "The Power to Reduce CO_2 Emissions – the Full Portfolio"(available at www.epri.com), which depicts the major activities in each of the four technology areas which must take place to achieve a robust set of integral advanced coal/CCS solutions. Important but not shown in the figure are the interactions between RD&D activities. For example, the ion transport membrane (ITM) oxygen supply technology shown under IGCC also can be applied to oxy-combustion PC units. Further, while the individual goals related to efficiency, CO_2 capture, and CO_2 storage present major challenges, significant challenges also arise from complex interactions that occur when CO_2 capture processes are integrated with gasification- and combustion-based power plant processes.



Source "The Power to Reduce CO2 Emissions – the Full Portfolio," http //epri-reports org/DiscussionPaper2007 pdf

Figure 1 – Timing of advanced coal power system and CO_2 capture and storage RD&D activities and milestones

RD&D Investment for Advanced Coal and CCS Technologies

Developing the suite of technologies needed to achieve competitive advanced coal and CCS technologies will require a sustained major investment in RD&D. As shown in Table 1, EPRI estimates an expenditure of approximately $8 billion will be required in the 10-year period from 2008–17. The MIT *Future of Coal* report estimates the funding need at up to $800–850 million per year, which approaches the EPRI value. Further, EPRI expects that an RD&D investment of roughly $17 Billion will be required over the next 25 years.

Investment in earlier years may be weighted toward IGCC, as this technology is less developed and will require more RD&D investment to reach the desired level of commercial viability. As interim progress and future needs cannot be adequately forecast at this time, the years after 2023 do not distinguish between IGCC and PC.

Table 1 – RD&D Funding Needs for Advanced Coal Power Generation Technologies with CO_2 Capture

	2008–12	2013–17	2018–22	2023–27	2028–32
Total Estimated RD&D Funding Needs *(Public + Private Sectors)*	$830M/yr	$800M/yr	$800M/yr	$620M/yr	$400M/yr
Advanced Combustion, CO_2 Capture	25%	25%	40%	80%	80%
Integrated Gasification Combined Cycle (IGCC), CO_2 Capture	50%	50%	40%		
CO_2 Storage	25%	25%	20%	20%	20%

By any measure, these estimated RD&D investments are substantial. EPRI believes that by promoting collaborative ventures among industry stakeholders and governments, the costs of developing critical-path technologies for advanced coal and CCS can be shouldered by multiple participants. EPRI also believes government policy and incentives also will play a key role in fostering CCS technologies through early RD&D stages to achieve widespread, economically feasible deployment capable of achieving major reductions in U.S. CO_2 emissions.

<u>Comments on whether the revised FutureGen approach should allow for advanced coal technology systems, other than IGCC, which also would meet the performance requirements</u>

As stated previously, the portfolio aspect of advanced coal with integrated CCS technologies must be emphasized because no single advanced coal technology (or any generating technology) has clear-cut economic advantages across the range of U.S. applications EPRI and industry representatives have proposed a program to support commercial projects which demonstrate advanced PC and CCS technologies. The vision entails construction of two (or more) commercially operated USC PC power plants which combine state-of-the-art pollution controls, ultra-supercritical steam power cycles, and innovative CO_2 capture technologies. The projects described below would meet the restructured FutureGen performance requirements:

UltraGen UltraSupercritical (USC) Pulverized Coal (PC) Commercial Projects.
The UltraGen I plant will use the best of today's proven ferritic steels in high-temperature boiler and steam turbine components, while UltraGen II will be the first plant in the United States to feature nickel-based alloys able to withstand the higher temperatures of advanced ultra-supercritical steam conditions.

UltraGen I will demonstrate CO_2 capture modules which separate about 1 million tons CO_2/yr using the best established technology. This system will be about 6 times the size of the largest CO_2 capture system operating today (and that unit does not process flue gas from a coal-fired boiler). UltraGen II will treble the size of the UltraGen I CO_2

capture system, and may demonstrate a new class of chemical solvent if one of the emerging low-regeneration-energy processes has reached a sufficient stage of development. Equally, provided the technology is available, UltraGen II could be an oxy-combustion boiler. Both plants will demonstrate ultra-low emissions and will utilize control technologies identified by the DOE emission control programs. Both UltraGen demonstration plants will dry and compress the captured CO_2 for long-term geologic storage and/or use in enhanced oil or gas recovery operations

Figure 2 depicts the proposed key features of UltraGen I and II.

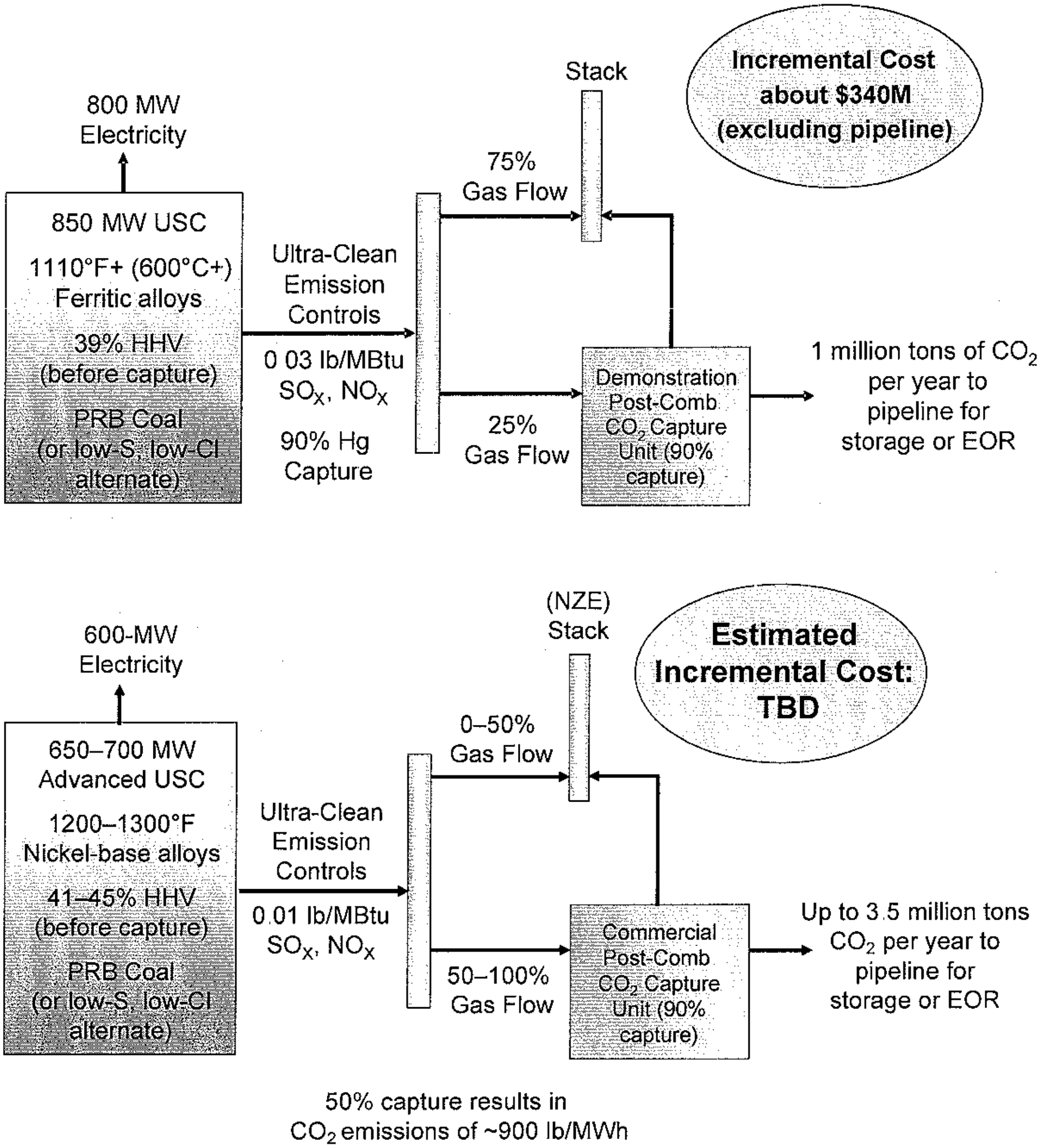


Figure 2 – Key parameters for UltraGen I (upper schematic) and UltraGen II (lower schematic), assuming a subbituminous feed coal such as Powder River Basin

The final project in the series is UltraGen III, which will operate with main steam temperatures up to 1400°F and, with boiler system design improvements, has the potential to achieve generating efficiencies of up to 50 percent This project will use materials qualified in the DOE's current boiler and steam turbine materials program. The UltraGen Initiative identifies the need for a test facility, ComTes-1400, to test materials and components in support of UltraGen III. Such a test facility is proposed within the DOE materials program and EPRI encourages its implementation

To provide a platform for testing and developing emerging PC and CCS technologies, the UltraGen program will allow for technology trials at existing sites as well as at the sites of new projects. Like the plan for the restructured FutureGen, EPRI expects the UltraGen projects will be commercially dispatched by electricity grid operators. The differential cost to the host company for demonstrating these improved features are envisioned to be offset by any available DOE demonstration funds, tax credits (or other incentives) and by funds raised through an industry-led consortium formed by EPRI

The UltraGen projects represent the type of "giant step" collaborative efforts that need to be taken to advance integrated PC/CCS technology to the next phase of evolution and assure competitiveness in a carbon-constrained world. Because of the time and expense for each "design and build" iteration for coal power plants (3 to 5 years, not counting the permitting process, and ~$2 billion), there is no room for hesitation in terms of commitment to advanced technology validation and demonstration projects.

The UltraGen projects will resolve technical and economic barriers to the deployment of USC PC and CCS technology by providing a shared-risk vehicle for testing and validating high-temperature materials, components, and designs in plants also providing superior environmental performance.

EXCELSIOR ENERGY

Response to the Request for Information on the Department of Energy's Plan to Restructure FutureGen

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INTRODUCTION

Excelsior Energy, Inc., ("Excelsior") is a current partner with the Department of Energy ("DOE") in the Mesaba Energy Project (the "Mesaba Project" or the "Project"), having been selected in 2004 for an award under Round II of the DOE Clean Coal Power Initiative and again in 2007 as one of sixteen Pre-Applicants to begin negotiations with DOE for a loan guarantee as authorized under Title XVII of the Energy Policy Act of 2005. Excelsior understands that DOE's intention, as expressed in its Request for Information ("RFI") is to restructure the FutureGen project "to ensure that it more closely reflects the immediate and future needs of the Nation, its power sector, and the taxpaying public." Excelsior offers these comments to assist the DOE in structuring a future solicitation that will ensure the immediate and future needs referenced in the RFI are met in the most timely, cost-effective, and realistic way possible.

We strongly agree that there is a "need for demonstrating the commercial viability of a new generation of advanced coal-based power systems that can cost effectively be coupled with" carbon capture and storage subsystems ("CCS"). We believe, however, that some adjustments should be made to the revised approach to FutureGen described in the RFI in order to ensure that real progress is made as soon as possible given the current status of IGCC technology to, as the RFI notes, "produce electricity from coal . . . in ways that mitigate the atmospheric emissions of carbon dioxide (CO2)."

Excelsior recommends three changes to the proposed project requirements, described below, to best achieve FutureGen's primary goals: (1) modify the requirement for approximately 90% CO2 CCS on one nominal 300 MW train, (2) expand the annual CCS requirement of one million metric tons in a saline aquifer to include enhanced oil recovery ("EOR") on at least an equal footing, and (3) remove unnecessary constraints on eligible projects with regard to sulfur and nitrogen oxides removal

These three changes will broaden the eligibility of projects that may be considered for awards under a restructured FutureGen to include commercial (in contrast to research and development) IGCC projects currently in the advanced stages of development, thereby better reflecting actual

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conditions in the marketplace and ensuring that taxpayer investment results in the earliest possible sequestration of CO2 emissions at the lowest possible cost

CONCERNS WITH THE PROPOSED APPROACH

While we applaud DOE's desire to emphasize early-commercial technology demonstrations and to eliminate the "living laboratory" aspect of the original FutureGen, we do not share DOE's view of the current marketplace with respect to the progress of previously planned integrated gasification combined cycle ("IGCC") coal-fired power plants. Nor do we believe that the revised approach described in the RFI either truly eliminates the living laboratory or realistically "build[s] on current power market trends"

At one time, as DOE notes, there were indeed more than 30 IGCC projects in various proposal stages. Today, however, just a handful are progressing forward. While DOE identifies "uncertainties regarding future CO2 emissions regulations" and the "actual costs of constructing and operating IGCC-CCS power plants" as major barriers to IGCC deployment, it is the perceived technology risk of these "first mover" facilities *without CCS* and the need for a competitive cost of electricity ("COE") for IGCC *without CCS* that present the highest barriers to commercial deployment in today's marketplace. Excelsior's proposed modifications to the RFI requirements address these major barriers to IGCC deployment while substantially moving forward on the path to achieving FutureGen's primary goal: mitigating the atmospheric emissions of CO2 while maintaining the Nation's ability to utilize its lowest cost and most abundant domestic energy resource.

ALLOW LOWER LEVELS OF CAPTURE AND STORAGE (30% SUBBITUMINOUS COAL) IN A STAGED APPROACH

A 90% capture level was appropriate for a "living laboratory" like the originally proposed FutureGen project, but a 30% CCS level is most suitable for a commercial IGCC facility using subbituminous coal as a feedstock.[1] The 90% capture level introduces unacceptably high levels of cost, technology, operations and maintenance, financial, and environmental risk to a commercial facility—as well as presuming the availability of a hydrogen-based combustion turbine. Excelsior believes that a 30% capture level is a more reasonable goal for a first-of-a-kind commercial-sized IGCC project. Our belief is that once capture and sequestration is "proven up" at the 30% level, DOE can then move on to fund "phase 2" CCS plans at the 50-60 % level, followed by 90% thereafter. This staged approach is key to any successful demonstration and commercialization effort, especially one so critical to our country's efforts to stabilize atmospheric concentrations of CO2.

When utilizing subbituminous fuel, more than 30% of total carbon from the feedstock is present in the undiluted and pressurized pre-combustion syngas stream as CO2 and 85% of this CO2 can be separated with existing commercial technologies, resulting in a 30% reduction in overall CO2

[1] Lower levels of capture from an IGCC plant using bituminous coal feedstocks would likely be in the range of 15–20% of the carbon present in the feedstock due to the higher energy output of bituminous feedstocks. The main point in response to the RFI is that lower levels of carbon capture that do not require a water gas shift reactor are the most economic and commercially viable means to obtain "real-world" data as soon as possible relating to material volumes of captured CO2 from the first fleet of ICGG-CCS power plants.

emissions from the IGCC plant. This can be done without the need for a water gas shift reactor, making it the most efficient and economic means of capture The CO2 removal system can be included in the initial IGCC plant or easily added later as a retrofit since no other plant modifications would be required. This low-cost 30% capture option will produce a CO2 stream of more than 1 million tons per year when applied to both trains of the Mesaba Project, facilitating a demonstration of CCS that is critical to the DOE's research, development, and commercialization path for IGCC with CCS. The Mesaba Project, designed to use subbituminous coal as its reference fuel, has a base case design that provides sufficient plot space to accommodate the addition of CO2 capture facilities, which will be included in the initial plant design during FEED.

However, because no IGCC plant has ever been operated with one or more shift reactors, each stage of shift reaction introduces additional first-of-a-kind technological challenges that could undermine and delay the goal of rapidly deploying and demonstrating IGCC with CCS. In addition, each stage of shift reactor will decrease the overall efficiency and output of an IGCC plant, thereby imposing additional material increases in the COE from an IGCC plant that again will likely undermine and delay the goal of rapidly deploying and demonstrating IGCC with CCS.

As indicated above, in addition to supporting a 30% CCS level for the FutureGen RFP, Excelsior urges DOE to employ a staged, modular approach to implementing CCS on the first generation of commercial IGCC plants A staged approach to CCS will allow projects to first demonstrate the technical and economic feasibility of a multiple-train, utility-scale IGCC plant. Following commercial operation, projects with base case designs to accommodate CCS equipment can commence capture. This staged approach allows projects already in progress to move forward with their current plant designs while the environmental and regulatory approvals of a CO2 pipeline and sequestration site progresses.

This "multitasking" concept is the most timely and cost efficient way to accelerate CCS by avoiding a necessary increase in the size and complexity of the first-mover IGCC projects beyond what a single project can support at inception. Advancing the CCS project separately from the power plant enhances project feasibility from both the permitting and financing perspectives for both the initial IGCC plant and the CCS Plan. This modular approach requires both allowing projects to pursue commercial 30% CCS technology and allowing simultaneous construction of the facility and EIS/permitting work on the pipeline and sequestration site.

Promote Capture and Storage Combined With EOR

In order both to minimize costs to ratepayers and taxpayers of CCS demonstration and to enhance our Nation's energy security, it is logical that projects take advantage of opportunities to combine CCS with EOR whenever possible. Rather than requiring every project receiving an award under a restructured FutureGen to sequester one million metric tons annually in a saline storage formation, and permitting only tonnage above that amount to be used for EOR, projects designed to demonstrate the economics of power plant CO2 emissions capture and transport for EOR should also be eligible

The interplay between anticipated CCS costs (capital, transport, operating and maintenance, monitoring, etc.) and revenues from EOR could provide an opportunity to explore a creative financing package with DOE and the financial community. The possibility of EOR revenues could impact the amount of DOE's cost share, potentially reducing the amount of funding required from DOE or perhaps allowing for repayment of amounts funded by DOE, either as a percentage or in absolute terms.

CONFORM TO EMISSIONS STANDARDS SET FORTH IN THE ENERGY POLICY ACT OF 2005

In its RFI, DOE maintains that one of its objectives is to, "Demonstrate the practical reality of IGCC with CCS coal-based electric power plants operated with different coal types." It appears that the 99% sulfur removal requirement—as with the other requirements, a carry-over from the original conception of FutureGen—has been written from the perspective of using only bituminous coal as a feedstock. Projects using subbituminous coal should not be disadvantaged by being held to a standard appropriate for bituminous, and we recommend that this requirement be revised to conform to similar requirements found in the Energy Policy Act of 2005.

Specifically, where subbituminous coal is 80% or more of fuel input, then the SO2 requirement should be phrased as a requirement to achieve an emissions rate of not more than 0.04 lbs/MMBTU. Also, other criteria pollutant emission levels beyond BACT should not be imposed. For example, the NOx emission level in the RFI would require selective catalytic reduction ("SCR"), which has never been demonstrated on any IGCC project. The Mesaba Project is being permitted with nitrogen diluent which we believe is BACT for IGCC NOx control at this time.

Overlaying the additional cost, technology, performance, and liability risks associated with CCS at the 90% scale onto an existing IGCC project envisioned in the RFI is, we believe, unlikely to result in a successful project that can achieve commercial operation. Further, the RFI imposes a counter-productive restriction on CO2 sequestration for enhanced oil recovery ("EOR") and an unnecessary constraint on eligible projects with regard to sulfur and nitrogen oxides removal. Changes in those three areas are likely to attract more competitive projects that can actually be constructed in the time-line DOE envisions, and at a cost that delivers the best value per ton of CO2 sequestered. These modifications will ensure that DOE can invest taxpayer funding in a variety of projects and can be confident that CO2 emissions will be sequestered at commercial scale. Indeed, with these revisions—along with appropriate sequestration monitoring and liability sharing provisions—Excelsior would be very interested in adapting the Mesaba Project to participate in the restructured FutureGen program.

PROJECT DESCRIPTION

The Mesaba Energy Project is an IGCC electric power generating station using subbituminous coal as its reference fuel, with nameplate capacity of 770 MW, a gross output of 740 MW, and nominally rated to deliver 606 MW (net) of electricity. Excelsior, an energy development company based in Minnetonka, Minnesota, is developing the Project on behalf of its affiliate, MEP-I LLC ("MEP-I"). Excelsior initiated development of the Mesaba Project in 2001, has achieved numerous significant milestones, and is on schedule to begin construction in 2009 and commence operations in 2013

The Mesaba Project is one of the most advanced IGCC projects in the country and has received significant public support, both financial and otherwise, at the local, regional, state, and national levels. The Project sponsors, supporters, and partners have spearheaded state and federal efforts to encourage both the deployment of IGCC and the development of carbon capture options.

The Project was selected to receive $36 million of funding in Round II of the DOE Clean Coal Power Initiative The Mesaba Project was selected based on its contribution to the DOE priority of commercializing gasification-based electricity production.

In the last twelve months, significant progress has been made on environmental permitting, transmission siting, and required Midwest Independent Transmission System Operator ("MISO") transmission network upgrades, regulatory approvals, and the Process Design Package ("PDP") related to the Project In late 2007, the Project was selected as one of sixteen Pre-Applicants invited to submit a full Application for a Federal loan guarantee authorized under the Energy Policy Act of 2005 Excelsior has also applied for Federal tax credits, which if awarded will further strengthen the Project's leading capability to demonstrate the commercial viability of IGCC.

In 2007, the Electric Power Research Institute ("EPRI") used the design of Excelsior's Mesaba Energy Project as the basis for its first pre-design specification for an IGCC plant using subbituminous coal feedstock. The pre-design IGCC plant specification summarizes technical information in the permit application for the plant The data is critical for regulators in determining whether to grant approvals to utilities to build these new state-of-the-art generation plants. EPRI analyzed data that was available in the permit application filing and condensed thousands of pages into a 183-page document. This work is being performed as part of EPRI's CoalFleet for Tomorrow Program, a collaborative involving more than 50 power industry companies to encourage the early deployment of advanced coal power generation technology. A key aspect of the CoalFleet program is to promote standardization of design, which lowers initial capital cost, supports repeatable, reliable performance, and reduces the time to develop an IGCC plant.

The Project is expected to be one of the first multi-train IGCC facilities and is being implemented with a commercial structure to provide power at a competitive price. In doing so, it will demonstrate that IGCC is a commercially viable power generation option, thereby directly addressing one of the remaining obstacles to widespread market penetration of this critical component of the nation's energy and environmental strategy.

Excelsior has proposed a plan for CCS to the Minnesota Public Utilities Commission ("MPUC") and expects that the Project will be the first demonstration of significant CCS from a fossil fueled power generation plant. It will utilize commercially available carbon capture technology to capture up to 30% of the CO2 from the plant, commencing when the MPUC approves the plan to do so.

MESABA ENERGY PROJECT: PLAN FOR 30% CARBON CAPTURE AND STORAGE

Excelsior has identified the opportunities for capture and sequestration of CO2 emissions from the Mesaba Project based on work conducted by the Energy and Environmental Research Center ("EERC") at the University of North Dakota (DOE's program manager for the Plains CO2 Reduction Partnership ("PCOR")) Excelsior has undertaken significant CCS planning as an active member of the PCOR, one of the regional DOE-sponsored partnerships. The activities conducted under this partnership initiative are divided into the three following phases: (1) characterizing carbon sequestration opportunities (such Phase I activities conducted 2003–2005), (2) conducting small scale field tests to validate such opportunities (Phase II conducted 2005–2009), and (3) conducting commercial-scale, long term carbon sequestration projects (Phase III conducted 2008–2017). As part of the Phase II efforts of the PCOR initiative, Excelsior contracted with the EERC to assess CO2 pipeline routes and sequestration options that would be important components of a future carbon management program for the Project. In its characterization of such options, PCOR identified and generally prioritized carbon sinks that are compatible with the composition of the CO2 gas streams that can be removed from the syngas produced by the Project.

This CCS plan was prepared to provide a concrete option for the State of Minnesota to meet its obligations under future CO2 regulations that will affect coal-fired power plants, including the Mesaba Energy Project. Excelsior undertook the plan with the goal of providing the MPUC with information about all options available now and in the future with respect to carbon management through capture and geological sequestration from the Mesaba Project. This plan would form the basis of another partnership with DOE under a restructured FutureGen approach, and could result in a commercially viable CCS demonstration from the Project at least one year earlier than the schedule envisioned by DOE in its RFI

Through DOE funding, the additional capital and operating costs to ratepayers of implementing CCS would be reduced. The benefits would include revenues from EOR and the ability to cost-effectively comply with legislation limiting or regulating carbon dioxide emissions, whether in the form of avoiding carbon taxes or the purchase of allowance credits, or the ability to reduce carbon emissions to levels specified on a fleetwide or statewide basis.

The least-cost option for CCS presented by the Mesaba Project entails capture and sequestration carbon dioxide present in the syngas, which represents greater than 30% of the total carbon dioxide emissions from the plant. Technologically, this option would entail the installation of amine scrubbers downstream of the acid gas removal system in the IGCC power stations to remove up to 85% of the CO2 in the synthesis gas that fuels the plants, resulting in an overall CO2 capture rate of 30% for the plant. This technology is available now to achieve 30% capture at a relatively low cost. This option could be implemented as early as 2015, following the commercial operation date for the first unit of the Mesaba Energy Project. Implementation of CCS prior to the availability of credits or carbon avoidance benefits would rely exclusively on DOE funding and revenues that may be available from EOR. Sequestration at EOR sites would have higher costs, due to the longer distances to the candidate oil fields, than would sequestration in saline formations closer to the plant site. Those additional costs would be weighed against the revenues that would accompany the supply of CO2 for EOR.

In an EOR scenario, the captured CO_2 would be transported via pipeline to oil fields in the Williston Basin in North Dakota, southwestern Manitoba, and/or southeastern Saskatchewan. Once the CO_2 arrives at its destination, it would be sequestered underground in connection with EOR operations. Alternatively (or perhaps in addition to the EOR scenario), the saline formation scenario would entail transporting the CO_2 to a saline formation located in North Dakota but much closer to the plant site, thereby reducing pipeline costs but eliminating (or reducing) the revenues associated with the sale and beneficial use of the CO_2.

CONCLUSION

Excelsior appreciates the opportunity to comment on the proposed restructuring of the FutureGen approach. We applaud DOE for making the determination that a number of different, commercial-oriented sequestration projects will provide greater validation of combining advanced coal-fired electricity generation with CCS technology than one large, primarily government-funded project. By adopting the changes we recommend, DOE can ensure that it will receive the widest possible range of competitive bids and thereby secure the earliest possible and most meaningful demonstration of sequestration at the lowest net cost.

Thank you again for the opportunity to offer our views on these important issues.

Sincerely,

Thomas Micheletti

Thomas Micheletti, Co-Chief Executive Officer

Julie Jorgensen

Julie Jorgensen, Co-Chief Executive Officer

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FutureGen™ ALLIANCE

Clean Energy for a Secure Future

FutureGen Alliance
Response to DOE's Request for Information

March 3, 2008

Climate change is one of the most pressing environmental concerns, and it is clear that Congress intends to develop policies to address the concern. Irrespective of which specific climate policy is ultimately adopted by the U.S., the success of that policy and our economic future, will hinge on the availability of affordable low-carbon technology Nuclear, renewables, biomass, and efficiency will all be part of the low-carbon technology solution However, given that coal is used to generate over 50% of the electricity in the U.S and is projected to remain the backbone of the U.S. electricity system for most of this century, the availability of affordable, near-zero emission coal technology, incorporating carbon capture and sequestration (CCS), is essential to our future

The Federal government has a pivotal role to play in fostering the development and deployment of near-zero emission coal technology. It is important that, as a nation, we invest at the scale required to develop, prove, and deploy CCS technologies to the marketplace While estimates vary, the required investment is certainly in excess of $10B over the coming decade. This investment in our nation's future must be supported by the development and demonstration of near-zero emission coal technologies and CCS in a variety of applications

The U.S. Department of Energy is to be commended for its vocal support of near-zero emission coal technology, including CCS. Its support of this technology was recognized in its initial support of the FutureGen project as originally envisioned, but the Department's proposal to restructure FutureGen fails to recognize the scale of the challenge that this nation, and indeed the world, is facing. It delays technology development and integrated demonstration of commercial scale CCS by five years or more. It backs away from a non-profit partnership that has been created to act in the public benefit and broadly share its technical results throughout the world. It rebuffs the participation of international companies (and countries) that are critical to the ultimate deployment of clean coal technology around the world; and it undermines the reliability of the U.S. Department of Energy as a partner.

Therefore, regardless of what other projects that the DOE proposes, it is essential that the Department reaffirms the agency's position as a global leader in near-zero emission coal technology and CCS development by maintaining its historical position that FutureGen at Mattoon is the top priority project in advancing CCS technologies.

FutureGen at Mattoon

The FutureGen Industrial Alliance has pledged approximately $400 million dollars under its current cooperative agreement with DOE. This level of non-profit financial donation, by the coal and coal-fueled utility industry, to a DOE program, and without any opportunity for financial return on its donation, is unprecedented. We hope that the administration and the Congress will view this fact as proof of the importance of FutureGen at Mattoon. The Alliance urges the Department to continue the FutureGen at Mattoon project with the non-profit Alliance.

- FutureGen at Mattoon offers DOE an opportunity to beat its proposed timeline. DOE's Request for Information (RFI) suggests an on line date of 2015. The FutureGen Alliance has delivered five years of progress, including contract negotiations, an enthusiastic and committed local community, a site that is technically and legally ready to go, a design and cost estimate, a final environmental impact statement, vendor relationships, and a team of fifty engineers and scientists. No fully integrated, near-zero emission power-plant project in the world can compete with FutureGen in terms of its ability to move forward with urgency on the required technology development and demonstration.

- FutureGen at Mattoon will meet or exceed all DOE emissions and CO_2 capture goals. All emissions and CO_2 capture criteria included in the FutureGen Report to Congress and DOE's current Request for Information (RFI) will be met by FutureGen at Mattoon, ***including 90% CO_2 capture***.

- FutureGen at Mattoon is fully integrated and commercial scale. FutureGen at Mattoon incorporates a commercial-scale gasifier and commercial-scale "Frame 7" turbine. As configured, and with the commitment to share lessons learned widely, it gives industry a chance to learn about the cost, performance, and operating strategies for an integrated system with CCS.

- Public benefit and information sharing is a hallmark of FutureGen at Mattoon. As a nonprofit enterprise, the FutureGen Alliance will broadly share information from the project, facilitating the deployment of commercial, near-zero emission power plants throughout the world. Alternative for-profit approaches may be complements, but they will feature protection of technological know-how and IP within individual companies rather than sharing it for broad benefit.

- International involvement is essential to success and FutureGen at Mattoon includes it at an unprecedented level. Thirteen companies with operations on six continents are participating. Climate technologies must be globally acceptable and globally deployed, or they will not be effective. International participation has been exceptionally well-managed and has added to the performance of the project. No other project can replicate FutureGen at Mattoon's level of international involvement

- FutureGen at Mattoon provides a platform for testing advanced technologies, which accelerates technology development and saves the taxpayer money. Once built, and power generation, carbon capture, and sequestration operations are underway, FutureGen at Mattoon can serve as a test bed for advanced technologies emerging from DOE's Fossil Energy R&D program and industry R&D efforts. Such testing will not interfere with the primary mission of the facility and provides a cost-effective approach to advance technology. Alternative testing approaches will be far more expensive Areas where DOE expects advancements to occur include oxygen production, gasifier improvements, gas clean-up, H_2 and CO_2 separation, H_2 turbine advancements and fuel cells. By proposing to end its support of FutureGen at Mattoon, DOE will be increasing the cost and difficulty of testing the very advanced technologies that its program managers seek to develop and deploy.

- FutureGen at Mattoon's costs are manageable. As with all global energy infrastructure projects, costs have increased since 2003. However, between the approximately $400 million in cash the Alliance is contributing and plant revenue that is being returned to DOE, the costs are manageable and a good national investment. Alternative projects that truly deliver the same results will not be cheaper Further, the Alliance's offer to sit down with DOE and discuss cost containment strategies remains an open offer

Additional Projects and DOE's Proposed Restructuring

The Alliance believes that it is in the national interest to complement FutureGen at Mattoon with additional projects in a variety of engineered applications and a variety of geologies. However, complementary projects must not come at the expense or delay of the #1 priority, FutureGen at Mattoon. Currently, DOE's proposed restructuring leaves many unanswered programmatic questions. Further, a number of technical issues associated with the restructuring are of concern Specific concerns about the DOE proposed restructuring include:

- DOE's schedule under the restructuring proposal is unrealistic. DOE has an important obligation to the taxpayer to follow comprehensive contracting processes, conduct technology reviews, and prepare an environmental impact statement on any new project. The schedule in the RFI (i.e., a proposed on-line date of 2015) is not realistic for a project that meets 100% of the stated goals. Many potential industrial partners are unfamiliar with DOE's required practices, and it is important that the DOE inform them of a reasonable schedule so that they can properly conduct the project and deal with their third-party investors. Overly optimistic schedules are a disservice to Congress, industry, and the public.

For DOE to identify an alternative, fully integrated project that meets all the performance goals DOE has stated are critical, the following schedule would be more realistic:

- 2009+: project selection and cooperative agreement negotiation
- 2012: completion of preliminary design, environmental impact assessment and record of decision
- 2013: completion of detailed design and procurement of major technology components
- 2017: completion of construction
- 2018: initial operation
- 2022: completion of test period

- DOE's restructured approach has problematic business parameters. DOE's proposal implies that 90% capture simply involves the addition of new technology to an existing IGCC. It does not. The complex integration of CCS into a commercial IGCC plant will entail significant modifications to many other systems, including commercial systems inside the base plant. It would also largely require a restart of design work done to date on the base commercial plant. Thus, the government, its procurement rules, and its oversight practices could easily extend into the commercial, for-profit power plant. Further, applying FutureGen funds to a project with anything appreciably less than capturing 90% of the ***total*** CO2 emissions from the ***entire*** plant would fall short of what is needed to rapidly develop near-zero coal plants.

- DOE's restructured approach does not address the increased marginal cost of electricity. The modified plant that DOE proposes that industry build *will cost substantially more to operate* than a traditional plant. DOE's RFI is largely silent on operating costs. Because power plants dispatch electricity to the grid based on their marginal operating cost, the approach DOE proposes could result in a plant that is too expensive for industry to operate

  For example, a Midwest utility commission which recently evaluated an IGCC project concluded it needed to approve more than a 15% increase in the cost of electricity to ratepayers in order for the project to move forward. DOE's proposal to add 90% capture to any commercial IGCC project, would increase the cost of electricity further, likely by another 20% or more. Who will pay this added incremental cost in the restructuring proposal? DOE? The industrial partner? The ratepayers?

- Increased appropriations will be required to offset Federal taxation. DOE is proposing moving away from its non-profit partnership with the Alliance. While it is appropriate for DOE to work with for-profit and non-profit entities, the precedent in the clean coal power initiative is that DOE grants awarded to for-profit entities can be subject to taxation by the IRS, if determined to be income. Thus, whereas 100% of the funding going to FutureGen at Mattoon goes to on-the-ground technology and operations, under DOE's new program, DOE will need increased appropriations if it intends to make the same ultimate on-the-ground investment in technology and operations. This could result in either: 1) hundreds of millions of dollars of additional appropriations to offset taxes or 2) a major dilution of DOE's program investment through taxation.

- Uncertainties created by the annual appropriations process must be mitigated. DOE is seeking new commercial projects. Commercial projects cannot easily proceed with certainty and garner commercial financing if DOE is going to make its project funding subject to annual appropriations. If DOE wants its new approach to succeed, it must have 100% advance appropriations for each project or find some other mechanism to guarantee funding

- DOE's restructured proposal must include some guaranteed mechanism for reliable DOE participation. By restructuring FutureGen and ceasing to cooperate on FutureGen at Mattoon, DOE has indicated that it is willing to walkaway from public-private partnerships and international participation even though DOE has signed an agreement with the private partner. New industry partners must receive assurance that the same thing will not happen on future projects, which would make the industry investment a stranded asset.

- DOE needs to clarify the rules for information sharing in any solicitation. Sharing technology performance and operating strategies is important to replicate the technology worldwide and at lower costs. DOE's plan limits information sharing as the proposal is designed to entice for-profit participation in commercial projects, which is not conducive to sharing IP and other information with non-participants.

- DOE needs to clarify how 90% capture will be measured. DOE's proposal is not specific about how the 90 percent CO_2 capture rate is measured within the plant. *It must be measured as the percentage of the total CO_2 that could be generated by the entire plant, not just a portion of the total CO_2 or 90% of a slipstream.* It would be a serious mistake if this target level is relaxed. Ninety percent is a technical goal designed to ensure a sustainable future for coal. Today's commercial projects cannot technically or economically handle this goal.

- DOE should clarify how liability protection be handled for injected CO_2 and trace constituents. DOE has provided no mechanism to protect companies from the liability associated with injected CO_2. It took the states of Texas and Illinois several years to address these issues through legislation specifically for the project developed by the FutureGen Alliance. Without this protection, projects will face delays making it difficult for companies to take on these liabilities

- Third-party financing is essential to projects and DOE must allow it. DOE rejected minimal third-party financing (e.g., <20% of the total project cost) for FutureGen at Mattoon. Many, if not all projects that come forward in response to

DOE's RFI and subsequent solicitations will require third-party financing. It is common for commercial projects to be 50-80% financed. DOE must allow for this flexibility if it wants its restructured approach to be successful.

- Title transfer to industry is a prerequisite. DOE originally intended to provide industry with the title for the FutureGen at Mattoon project; however, it changed its position part of the way through the project, instead electing for federal ownership. Under the restructured effort, DOE must provide 100% title for the entire project to industry as commercial projects typically require title rights to secure third-party financing. Further, because capture is intertwined with the base plant, the industrial partner cannot accept government ownership of part of its commercial enterprise.

- 100% of revenue must go to the industry partner. Unlike FutureGen at Mattoon, in which DOE shared in the project revenues substantially offsetting Federal investment, for projects conducted under DOE's new approach, DOE would need to agree that the plant revenues go 100% to the industrial partner so that participants can generate a commercial return on a commercial project.

- Contractual streamlining is a prerequisite for project success. Incorporating CCS technology into a power plant will require significant changes in the design and operation of the base commercial plant. DOE cost sharing must not lead to a requirement that government accounting practices and procurement rules apply to the base plant, even though it is being modified to suit the government's purposes. Attaching such strings to a commercial project would have significant cost and schedule impacts on a commercial project.

In its 2004 report "FutureGen Integrated Hydrogen and Electric Power Production and Carbon Sequestration Research Initiative", DOE acknowledged the necessity for the type and level of risk sharing associated with FutureGen at Mattoon, if technology is to advance at the required pace. In its report, DOE said:

"FutureGen's integration of concepts and components is key to providing technical and operational viability to the generally conservative, risk-adverse coal and utility industries. Integration issues such as the dynamics between upstream and downstream subsystems (e.g., between interdependent subsystems such as the coal conversion and power and hydrogen production systems and carbon separation and sequestration systems) can only be addressed by a large-scale integrated facility operation. Unless the production of hydrogen and electricity from coal integrated with sequestrating carbon dioxide can be shown to be feasible and cost competitive, the coal industry will not make the investments necessary to fully realize the potential energy security and economic benefits of this plentiful domestic energy resource."

Technology advancements and market changes in the last five years have not changed this need for a full scale demonstration envisioned in DOE's report and FutureGen at Mattoon.

There is no project in the world that can move near-zero emission power and CCS further or faster than FutureGen at Mattoon. It is non-profit, includes unprecedented international involvement and information sharing, and has a site that is technically and legally ready-to-go. Alternatives will cost the country five years or more of delay and/or deliver less in terms of results. As Congress and the administration debate the appropriate structure for the FutureGen program, we urge that: these factors be taken into account; FutureGen at Mattoon be maintained as a global flagship project that is the nation's top priority for advancing near-zero emission coal technology; and complementary projects be added to the program as the budget allows.

GE RESPONSE TO DOE REQUEST FOR INFORMATION (RFI) ON THE DEPARTMENT OF ENERGY'S PLAN TO RESTRUCTURE FUTUREGEN (DOE-SNOTE-080130-001)

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DOE's decision to restructure FutureGen makes a lot of sense. It recognizes that IGCC with carbon capture can be commercially supplied today -- for example, GE's commercial 630MW IGCC plant is already carbon capture ready. However, FutureGen's restructuring must satisfy two critical and urgent needs:

- Validation of CO2 sequestration at large scale and
- Demonstration that utility powerplants with carbon capture can be successfully integrated with sequestration.

DOE's proposed restructuring can provide the platform to satisfy these needs and move coal forward. Implementation of carbon capture and sequestration (CCS) at a national scale will be confronted by a broad diversity of geological settings for sequestration sinks. This will be the case even with a focus limited to saline aquifers. The needs in greater detail are:

- Proving that an operating utility plant can be integrated with a CO2 storage facility.

  We agree that large scale commercial operation is an important criterion to gain credibility and relevant operating experience with CCS. Successful integration requires that both facilities – power and sequestration – are able to operate in a long-term, real-world utility context of load following, turndowns, shutdowns and upsets.

- Performing large-scale sequestration in multiple geologic settings sufficient to provide design and application experience for CCS to proceed commercially and on a large scale.

  Only multiple sites can prove critical design data for sequestration such as capacity, injectivity, and permanence of storage that is needed to provide a robust basis for future projects.

GE is not proposing specific projects in this response. As a provider of IGCC technology to the utility power industry, GE looks to its customers to define those projects that satisfy their requirements for new coal power. We are however, cognizant of, and highly sensitive to, utility requirements for committing to the significant investment – typically $2 Billion or more – required for large commercial coal power projects. That commitment can only be made when risks and costs are understood and quantified. The current environment and level of understanding of CCS does not provide the basis to make these large commitments. DOE's stated goal is to gain early commercial experience validating cleaner coal technologies through multiple demonstrations of CCS technology in commercially operated IGCC-CCS electric power plants. We believe that a properly crafted program structured by DOE can allow utilities and project developers to move forward to participate in support of DOE's goals and concurrently move coal forward despite today's uncertainty.

THE CHALLENGES

There are currently several barriers to achieving DOE's stated objectives that must be met as a part of any future program. These are:

1. The lack of a clear regulatory framework for CO2 storage facilities that addresses issues associated with the definition of property rights, liability, site licensing and monitoring, ownership, compensation arrangements and other institutional and legal considerations.
2. An absence of regulatory protocols for sequestration projects including site selection, injection operation, and eventual transfer of custody to authority.
3. The lack of either a regulatory constraint or a market value for CO2 set by either price, or avoided tax.

All will take time to resolve – and more time than DOE can wait. In order for commercial entities to step forward to participate, all of these barriers need to be addressed in the program structure. The original FutureGen Alliance was able to obtain State assumption of title to, and liability for, the CO2 produced. With respect to a commercial utility project, obtaining such assumption of liability may be more difficult. Solutions for transporting CO2, ownership of the storage reservoirs, injection of the CO2 and liability issues attendant to the near term and then long term storage of the CO2 must be addressed at the outset of the program. The DOE, and other agencies of the federal government such as the DOT and the EPA, have major roles to play in this process. In its program FOA, the DOE should provide explicit solutions and provisions of exceptions and relief for these issues such as Federal assumption of CO2 ownership after a set time period

Capture Level: The FutureGen RFI has set a carbon capture level of 90%. We think this is the wrong target. Requiring a more stringent standard for coal than natural gas places an unnecessary and unwarranted burden on coal. It should be recognized that 90% capture will result in net CO2 lb/MWh that is approximately 1/3 of that from a natural gas combined cycle plant. While 90% carbon capture is technically feasible with IGCC, it incurs higher capital expense and operating costs than lower levels of capture. We are also in a period when capital costs have and are continuing to rise substantially for all power plants so that the cost issue is even more acute. While the 90% requirement is appropriate for a development platform such as the original FutureGen, there is little gain from requiring a generating unit that is required to provide competitive electric power to meet this criterion even to qualify for the proposed DOE incentives. We therefore believe that 65% capture is the right target and consistent with what would be the outcome of a CO2 BACT analysis.

Controlling Program Costs: This program will likely be executed before a market value for carbon develops sufficient to offset the added cost of CCS. Program funding therefore needs to be adequate to cover the total cost that a utility will face in implementing IGCC with carbon capture. These include 1) a baseline capital cost premium for IGCC, 2) the incremental capital costs of carbon-capture equipment plus 3) cost of day-in/day–out capture, purification, compression, transport, sequestration and monitoring of CO2. While the initial cost of IGCC is higher, the net cost including CCS will be lower than with combustion technologies and, on this basis, the premium for IGCC is warranted.

Costs can be significantly reduced, and the number of projects increased, by requiring initial capture levels that are only sufficient to achieve validation of large-scale integrated capture and sequestration.

AN ALTERNATIVE APROACH

Siting and permitting of a commercial coal utility plant – even IGCC -- is already difficult and complex. The addition of storage will add yet another level of complexity, difficulty and schedule impact to the permitting process. Given the lack of experience in 1) sequestration, 2) its coupling to a utility power plant, and 3) new and yet-to-be-defined public, regulatory and legal challenges to be overcome, this is essentially a learn-as-you-go program. We therefore recommend a phased approach having distinct funding tranches resulting in retirement of the above risks synchronized with increased investment and growing level and certainty of required Federal appropriation. Those phases are:

Phase 1 CCS Feasibility & Project Qualification: Candidate new IGCC projects are funded by DOE for a feasibility assessment. This assessment will consist of candidate CO2 storage facility identification, preliminary geologic characterization and IGCC plant feasibility study. A key criterion for the design is a 500MW minimum scale -- not a slipstream -- so that integration experience between an operating commercial IGCC plant and a storage facility is obtained. The plant feasibility study would be based on an initial carbon capture level suitable to achieve sequestration validation. If not initially chosen as the capture level, the plant feasibility study would also include features for later retrofit capability to achieve CO2 performance equivalent to that of NGCC. Each site might need evaluation and testing of multiple sequestration sites. The estimated cost would be ~$1-$2MM per project and a target of 20 projects. DOE funding would both catalyze and formalize the program to develop an inventory of candidate projects.

Phase 2 Front End Engineering Design: Those IGCC projects passing Phase 1 criteria for an acceptable CCS demonstration would be entitled to enter into a preliminary engineering phase. This phase includes an IGCC plant Front End Engineering Design (FEED) study and detailed characterization and FEED of a primary CO2 storage site. The plant would be designed with specific features to accommodate a future retrofit to 65% capture. The FEED would incorporate provision for initial configuration with partial capture sufficient to achieve sequestration validation. For example, 15%-20% capture would produce 600K-800K tons CO2/year for a 600MW plant. While this is less than the 1MM tons/yr initially envisaged by DOE, it can be sufficient to support several injection wells while stressing a storage facility to validate capacity for potential future increases in CO2 capture. IGCC and storage facility site permitting applications would be completed. The study would determine a trigger cost of CO2 CCS for comparison to a market signal or credit price for CO2 (when and if it develops). The estimated cost per Phase 2 project would be ~$50MM ($20MM Plant FEED + $20MM detailed sequestration site characterization + $10MM storage facility FEED) and a target down-select from Phase 1 of 15 highest scored projects.

Phase 3 Construction and Commissioning: Based on a scored outcome of Phase 2, twelve (12) proposed projects would be entitled to go forward with detailed engineering and project execution. Key scoring criteria for funding award would be based on progress towards permitting, variety of coal source, and the diversity of sequestration resource (i.e. – avoidance of multiple plants reporting their CO2 to the same geologic structure). These plants are initially equipped with partial capture to serve as the CO2 source for sequestration validation. DOE funding would be needed to offset the initial cost premium for IGCC plus the incremental costs for capture equipment, storage facility development (indexed for inflation) and commissioning of the IGCC plant with capture and CO2 storage facility. The estimated cost per project would be $400MM.

Phase 4 Operational Validation: This phase would cover a three (3) year period of capture and sequestration. Monitoring and testing of the

CO2 reservoir would be carried out to validate storage capacity, model predictions of plume extent and geological response. DOE would provide a subsidy for incremental CCS operating costs until there is 1) a market signal (price, credit value or tax equivalent) for carbon that is greater than the capture and sequestration cost or 2) no more than three years of design rate sequestration or five total years of operation at which point CCS ceases and the plant can be returned to normal operation. As an example - 5 years would achieve the validation of CCS in that plant's particular geologic situation. (5 years = 1 year capture startup and commissioning + 1 year injection facility and well commissioning + 3 years of full capacity operation.) In the case of a market price for CO2 that exceeds the plants cost of CCS, DOE could be entitled to repayment of its costs from revenue in excess of cost and minimum return for the utility. The estimated cost per project for the Validation Phase would be $150MM (3 years $50MM/yr) for a total of 12 projects.

Phase 5 Retrofit to NGCC performance: Participating utilities would make a commitment to retrofit to a minimum 65% capture level (NGCC CO2 equivalency) when proper regulatory framework is set and the CO2 market price hits the trigger price developed in Phase 2. The utility would be required to cover the costs of upgrades to the IGCC plant including shift reactors, shift cooler and low-temperature gas cooling expansion, CO2 separation equipment (or AGR expansion), additional CO2 compression capacity and turbine combustion modifications. Cost per project $0 to the government.

What Constitutes an Eligible Project? The key features of a project that would be eligible for funding are:

- 500MW minimum
- Capable of operation with and without capture
- Pre-combustion capture (i.e. able to generate high purity CO2)
- Commercial operation (no slipstreams)
- Incorporates only commercially available technologies
- Accessible to one or more saline aquifer or EOR sites
- Capture sites have potential 30 year capacity at full-plant 65% capture
- Designed for retrofit to 65% capture including turbine fuel skid, free plot area and plant access for component modifications.
- Retrofit does not require scrapping/decommissioning of major process or power equipment
- Site utilities sufficient for demonstration and retrofit to NGCC (770lb CO2/MWh) equivalency

What can this approach accomplish? Compared to the original concept that requires significant up-front project commitment -- a lot. Specifically:

- A decision path for investment coordinated with a developing understanding of the CCS project and its risks.
- Significantly reduced per-plant investment = more project candidates
- Allows for future retrofit to higher capture levels as CO2 value evolves and as economics recommend
- Shared risk/benefit with participants with a path to cost recovery
- Operating experience on integration of capture and sequestration for a wider range of geographic locations, electric power grids, operating environments and their load profiles

Term of Projects: The DOE needs to address the expected term of the carbon capture demonstration. It is unsaid in the RFI but will need to be defined in the FOA. We believe that it should be limited to the time required to accomplish validation of the capture operation, its integration with the storage facility, and adequate stressing of the sequestration sink. However, after a plant is operating successfully with CCS, there is likely to be extreme public and environmental resistance to discontinuing CCS operation even if it means significant unrecoverable cost.

Integration of Power, Transport and Storage: Successful demonstration of an operating integrated power plant with a CO2 storage facility is an important deliverable of the program. The operation of the storage facility needs to be designed so that it can contend with upsets, load following, turndowns and shutdowns without effecting the operation of the power plant. Otherwise, the facilities may be commercially separate.

IGCC Applicability: Focus should be primarily on sequestration. This requires a high confidence in the carbon capture portion of the project and its ability to provide a consistent CO2 stream with high availability, high quality and consistency. Carbon capture with IGCC can be engineered and supplied today without the need for significant scale-up or development of new technology. Other technologies should be considered only if 1) they are at a similar state of commercial and technology readiness for carbon capture and 2) can provide high purity CO2 that will not add additional uncertainty or risk into the sequestration demonstration.

Clear Linkages Between DOE Programs: We recommend that DOE provide clarification and the methodology for linkages to other funding initiatives that have been authorized and/or appropriated. Combining these could provide a more powerful overall coal program. We do not have a clear understanding of how all these sources can be combined to work together. These other sources include 1) the Regional Sequestration Partnerships and their plans for Phase II and Phase III demonstrations, 2) the Clean Coal Power Initiative (CCPI), 3) the carbon capture and sequestration demonstrations (Sections 402 and 403 of the

2007 EISA), 4) the uncommitted Investment Tax Credits (EPAC 2005 - 48A), 5) Loan Guarantees (EPAC 2005 48A) and 6) the Western Integrated Coal Gasification project (EPAC 2005 Subtitle D Section 413). GE believes that there is a big opportunity for combining and focusing funds into an overall and clearly delineated and broad overarching program.

<u>*Summary:*</u> GE appreciates this opportunity to provide comment on DOE's RFI for FurtureGen's restructuring. It is a big step forward towards a strong future for coal power in the US provided that it avoids burdening seminal large-scale CCS projects with unneeded additional complexity and cost. These have the potential to divert attention from the real goal of proving the most challenging goal – that large-scale sequestration is viable and safe.

US Department of Energy
Request For Information
Plan to Restructure FutureGen

The US Department of Energy (DOE) has announced its intent to restructure the FutureGen program to directly support Carbon Capture and Storage (CCS) initiatives associated with Integrated Gasification Combined Cycle (IGCC) projects. This combination is recognized as IGCC-CCS. Rather than support further development of IGCC, DOE is responding to the increasing interest in capture of carbon dioxide (CO_2) from the combustion turbine exhaust and sequestering it in a suitable geologic location, such as a deep saline aquifer. DOE expressly indicates that this path will be a better use of funds. In this context CCS is considered "Post-Combustion CO_2 Capture" because it denotes removal of CO_2 from the turbine exhaust. DOE is willing to provide funding for CCS demonstrations associated with IGCC projects already being implemented by others. DOE requires capture of one million metric tons of CO_2 at 90% capture efficiency, and its sequestration. DOE is expressly excluding other uses of CO_2 such as for Enhance Oil Recovery (EOR). DOE is, however, seeking comment on whether to fund selected projects that are capturing CO_2 before combustion, such as during the processes associated with manufacture of Synthetic Natural Gas (SNG), which is known as "Pre-Combustion CO_2". While DOE intends to seek approximately $1.3 billion in its congressional budget request, the RFI does not make clear what scope of support it envisions.

Key goals of the Revised FutureGen are that it validate most of the original FutureGen objectives, including for example conforming to the same emission limit expectations as the original program; in addition to proving the technical and economic feasibility of IGCC-CCS as an integrated system.

Global Energy, Inc. – Background

Global Energy, Inc. is an environmentally focused alternative energy company pursuing clean energy solutions based on gasification technologies. Global Energy is using its ownership and operating experience to develop, construct, own and operate gasification facilities in the United States and in the United Kingdom. With three major near-term projects in active development, we believe we have the most advance portfolio of gasification and Integrated Gasification Combined Cycle (IGCC) projects in the U.S. and U.K. energy markets.

Global Energy has been in the gasification technology development business for twenty years. The Wabash gasification facility is currently operated by SG Solutions, which is a 50/50 joint venture between a Global Energy subsidiary and an electric utility cooperative. Global Energy has owned and operated the Wabash facility since late 1999. Since 1992, Global Energy has owned the Westfield Development Center, where a slagging fixed bed gasification technology was developed.

Global Energy has formed an alliance with HTC PurEnergy (HTC), headquartered in Regina, Saskatchewan, Canada where HTC will provide its expertise and proprietary technology in post-combustion carbon capture support our projects. HTC is well regarded internationally, particularly for its association with the Weyburn carbon dioxide based EOR project in Canada. HTC has proven expertise in measurement and monitoring of carbon storage to qualify storage quantities for credits in the international arena. HTC has ongoing projects in Norway, Australia, China, and in the Middle East. HTC will also utilize its extensive expertise in geology and geologic storage to benefit Global Energy projects.

Response to DOE Request for Comment

We believe that sequestration techniques and technologies themselves are probably more challenging than technologies needed for capturing CO_2 from an IGCC. Global Energy therefore recommends that DOE recognize and allow projects that advance sequestration knowledge, even though they may not be pure IGCC in nature. Sequestration can be advanced regardless of the source of CO_2. The gasification process effectively neutralizes the nature of the feedstock while producing synthetic gas. We therefore believe that, in order to gain the most information in the most expeditious manner, DOE should support IGCC capture and sequestration projects that utilize petroleum coke feedstock as well as those that use coal. We believe that DOE, by restructuring FutureGen, will enable deployment of IGCC power generation in a manner that is responsive to the growing national desire for Clean Tech solutions.

DOE is also specifically requesting comments relative to whether DOE should consider non-IGCC projects.

1. Global Energy recommends that DOE support management of carbon dioxide produced during production of synthetic products, such as Synthetic Natural Gas (SNG) or Coal To Liquid products, from oxygen blown slagging gasification processes. DOE can gain significant insight and experience in the geologic storage area, independently from capture technologies.

2. Global Energy opposes consideration of non-IGCC power generation technologies, such as circulating fluidized bed and supercritical boilers. It is very clear that direct combustion of coal for power generation is not an environmentally favored approach.

Global Energy Projects

Global Energy is responding to this Request For Information by describing and discussing three separate projects that we feel are well suited and well timed to benefit DOE's desire to expeditiously advance carbon management technologies via this initiative to restructure the FutureGen program.

In response to the DOE "Key Goals of Revised FututeGen" discussion in the RFI, Global asserts for all three projects – that the ten bulleted objects are reasonable and achievable. In particular, Global believes that the original FutureGen emission limits, noted in the 3rd bullet, are readily achievable.

The three projects, described separately on the following pages, are: **Lima Energy IGCC & SNG**, **SNG Export**, and **Kentucky Pioneer Energy**.

Lima Energy IGCC & SNG

Name and Point of Contact

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Project Location

The City of Lima
Allen County, OH
At former Brownfield Site Known as Lima Locomotive Works

Facility Address

1046 South Main Street
Lima, OH 45804-2044

Narrative Description

Lima Energy Company (Lima) has begun construction and is nearing completion of full financing. This includes provisions for both equity and construction financing. Once construction is completed, the construction facility will be replaced by bonds supported by the Ohio Air Quality Development Authority, which has already provided a resolution to this end. The Lima Energy IGCC is expected to commence operation in 2011, and will include carbon management from its inception.

We believe that the Lima Energy Project will prove to represent the first opportunity for DOE to achieve results in its carbon management (sequestration) objectives. Fortuitously, the City of Lima in Allen County, Ohio rests above a geologic horizon, known as the Mt. Simon Sandstone that is already known to be secure, with a hard cap layer above, which was previously evaluated and shown to have integrity locally.

The Project consists of a 540MW IGCC plus 75 million standard cubic feet per day of SNG into the natural gas pipeline system. Designed to process either petroleum coke or coal, Lima will capture approximately 2 5 metric tons of pre-combustion CO_2 during production of SNG. While the project has plans to develop a CO_2 based enhanced oil recovery solution in Ohio, it will also have a sequestration site suitable for CO_2 storage locally. The Project is also in the process of evaluating post-combustion capture capability for incorporation downstream of the combustion turbine exhaust. This quantity would represent approximately 3 million metric tons of CO_2. Our HTC partner will assist the project in implementing these plans.

Project Timeline

Having already begun construction, the project and its EPC Contractor plan a 3-year construction, from third quarter 2008, such that operation of the facility, including carbon management, should begin in 2011, well ahead of the DOE target of 2015.

Estimated DOE Contribution

The wording of the RFI suggests DOE willingness to fund the entire cost of the carbon management portion of a project, as long as it the associated IGCC project is otherwise completed by the applicant. On this basis, our assumption is that DOE currently anticipates this cost to be 100% of the CCS effort at an IGCC project, and further assume that these costs include any pipeline transportation necessary to achieve sequestration. These costs are projected as follows:

Post combustion capture at 90%, would, if feasible, utilize a proprietary HTC process already developed but adapted from conventional boiler applications, and sequestration of one million metric tons will require approximately $80-100 million, based on scale up of an existing process intended to capture 3-400,000 metric tons. In addition, compression and infrastructure to achieve sequestration may be as little as $25 million and as much as $100 million, depending on how close or far the ultimate sequestration site is to the Facility. Lima Energy expects to be at the lower end of this range, since the sequestration site is expected to be relatively local to the facility.

The Lima Energy Project already plans to capture CO_2 associated with manufacture of SNG. We are exploring Enhanced Oil Recovery (EOR) applications for this CO_2, but will also provide for sequestration locally, as noted above. Should DOE support management of carbon from pre-combustion processes, the following cost assumptions are made. Capture is inherent in production of SNG, and carries no cost for DOE. Compression and infrastructure to achieve sequestration would be comparable to the above case, or $25 to $100 million.

Technical, Financial or Legal Barriers

Lima Energy does **not** foresee insurmountable barriers to carbon sequestration. There is work to do, and permissions to seek, but we believe the project can and will serve as a template for carbon management in Ohio.

The State of Ohio is actively exploring appropriate policy initiatives that may prove helpful to standardizing the handling of legal and regulatory issues associated with carbon management in Ohio.

- The Governor of Ohio has proposed, and the Legislature is drafting language, to enable the Public Utility Commission of Ohio and Ohio EPA and Ohio Department of Natural Resources (PUCO-OEPA-ODNR) to jointly develop processes and procedures to facilitate and enable effective carbon management.

- We believe pipeline routing for handling CO_2 will require state oversight, but do not believe this issue should be seen as a significant barrier. The PUCO has been actively advocating for a CO_2 Pipeline for considerable time.

- Ohio Department of Natural Resources has the existing expertise and authority to oversee issues surrounding secure sequestration in horizons such as saline aquifers, as well as EOR applications.

  ODNR has significant information about the geology of Ohio and has published papers on the feasibility and viability of sequestration in the state. ODNR has indicated support of the Lima Project and its sequestration as well as EOR strategy.

<u>SNG Export at Wabash River Energy Facility</u>

Name and Point of Contact

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Project Location

West Terre Haute, Indiana
SG Solutions Gasification Facility (formerly known as Wabash River Energy)
Hosted at the Duke Energy Wabash River Generating Station

Narrative Description

The SG Solutions (SGS) Facility (formerly known as Wabash River Energy) began operation in 1995 as a DOE demonstration, with two EGAS gasifiers, though only one operates at any time. As part of its joint venture ownership of SGS, Global Energy retains the express right to use the second gasifier for its own purposes.

Development and financing of the SNG Export project is currently in progress, and an EPC contractor has been signed. When activated, the second gasifier will process locally mined coal to manufacture approximately 14 bcf per year of Synthetic Natural Gas (SNG) for commercial delivery into the natural gas pipeline system. An Air Separation Unit (oxygen supply) and complete downstream gas purification and Methanation processes will be added. The SNG Export facility will have certain common facilities with the existing plant.

Illinois basin coal will be supplied to the new facility from a nearby Indiana mine that we own.

We intend to identify a suitable sequestration site, reasonably close to the facility for storage of the Pre-Combustion CO_2 captured during the SNG manufacturing process. This may be an appropriate saline aquifer or coal bed methane site.

There may also be an opportunity to retrofit a post-combustion carbon capture process to the existing combustion turbine unit that is part of the existing IGCC.

Project Timeline

Construction of the SNG Export project will require approximately two years to complete, as much of the infrastructure already exists. Operations are therefore expected to begin by early 2011.

Estimated DOE Contribution

As noted above, the wording of this RFI suggests DOE willingness to fund the entire cost of the carbon management portion of a project, as long as the associated IGCC project is otherwise completed by the applicant. On this basis, our assumption is that DOE currently anticipates this cost to be 100% of the CCS effort at an IGCC project, and further assumes that these costs include any pipeline transportation necessary to achieve sequestration. These costs are projected as follows:

Post combustion capture at 90%, would utilize a proprietary HTC process already developed, but adapted from a conventional boiler application, and sequestration of one million metric tons will require approximately $80-100 million, based on scale up of an existing process intended to capture 3-400,000 metric tons. In addition, compression and infrastructure to achieve sequestration may be as little as $50 million and as much as $100 million, depending on how close or far the ultimate sequestration site is to the Facility.

Technical, Financial or Legal Barriers

SNG Export does **not** foresee insurmountable barriers to carbon sequestration. There is work to do, and permissions to seek, but we believe the project can and will serve as a template for carbon management in Indiana as well as nearby Illinois.

- Both Indiana and Illinois are actively developing programs to promote effective regulation of the carbon management process.

- Both states are believed to be developing strategies for pipeline transportation of CO_2, as well as legislative and regulatory processes and protections.

Kentucky Pioneer Energy

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Project Location - Proposal

JK Smith Site
Trapp, Clark County, Kentucky
Owned by East Kentucky Power Cooperative (EKPC)

Narrative Description

Kentucky Pioneer Energy (KPE) was originally developed as an IGCC demonstration utilizing a fixed bed gasification technology under agreements with EKPC. Though fully permitted, for commercial reasons the project did not advance as intended.

KPE will seek to work with EKPC to recommence development efforts and renew permits. KPE would reconfigure the project to produce approximately 24bcf per year of Synthetic Natural Gas (SNG) from Kentucky Coal and compress it into a natural gas pipeline, several of which cross the JK Smith site. We would also anticipate providing low cost fuel to EKPC for the several combustion turbines (approximately 500MW total) at the site, which would thereby meet the IGCC criteria of DOE. The JK Smith site has considerable existing rail and coal handling infrastructure in place, as it was originally designed by EKPC to support a major coal based generating station.

This facility would have the potential to produce both pre-combustion and post-combustion CO_2 for use in sequestration initiatives in Kentucky. KPE is aware, from communications with the Commonwealth of Kentucky, that there may be existing wells in the area that would be potentially useful for sequestration. We would also explore the potential for a coal bed methane or EOR project in reasonable proximity to Clark County.

Project Timeline

Construction of the Kentucky Pioneer Energy project may require four to five to years to develop, permit and construct, resulting in operations beginning between late 2012 and late 2013. We anticipate that the carbon management infrastructure development will require approximately the same amount of time. However, with considerable information still to be developed in this area, it is possible the CO_2 sequestration portion could perhaps extend into 2014.

Estimated DOE Contribution

As noted above, the wording of this RFI suggests DOE willingness to fund the entire cost of the carbon management portion of a project, as long as the associated IGCC project is otherwise completed by the applicant. On this basis, our assumption is that DOE currently anticipates this cost to be 100% of the CCS effort at an IGCC project, and further assumes that these costs include any pipeline transportation necessary to achieve sequestration. These costs are projected as follows:

Post combustion capture at 90%, would utilize a proprietary HTC process already developed, adapted from a conventional coal boiler application, and sequestration of one million metric tons will require approximately $80-100 million, based on scale up of an existing process intended to capture 3-400,000 metric tons. In addition, compression and infrastructure to achieve sequestration may be as much as $100 million, based on the potential distance from the site and the relatively hilly terrain in the area. Pre-Combustion capture from the SNG production will be a substantial cost due to the planned size of the plant.

Technical, Financial or Legal Barriers

KPE does **not** foresee insurmountable regulatory barriers to carbon sequestration, as the Commonwealth is keenly interested in development of solutions. There is work to do, and permissions to seek, but we believe the KPE project can serve as a template for carbon management in Kentucky.

- The generally hilly terrain in the area may pose added costs compared to other locations.
- Kentucky has begun developing strategies managing carbon sequestration issues and for pipeline transportation of CO_2, but these appear to still be formative.
- We are currently unfamiliar with the geology of Kentucky, but anticipate working closely with Kentucky Geological Survey and the University of Kentucky Center for Applied Energy Research, who are familiar and have specific delegation from the Commonwealth to assist in this area.

General Technical Considerations

Technically, CO_2 is readily absorbed in either common or proprietary solvents, and is processed in a manner very similar to conventional acid gas processing. A number of technical issues will need to be addressed, in relation to IGCC applications, but these are not insurmountable. Two examples of technical considerations are:

1. One challenge, with respect to combustion turbines, is to avoid undesired back-pressure on the turbine exhaust, which operates at very low pressures. Careful design of the flow of the turbine exhaust to the acid gas process will be necessary.

2. Another technical consideration is the need to understand the nature of the exhaust stream and its constituents, after CO_2 is removed, and the effect on exhaust stack design.
   a. Included in this, is the characteristics of post-capture emission and how the exhaust will need to be handled and permitted.

Legal and Regulatory Considerations

1. It is recommended that DOE make clear in the Funding Opportunity Announcement (FOA), what its intentions are with respect to NEPA requirements.
   a. Will an EIS or an EA be required?
   b. Will the EIS or EA be ONLY on the carbon management portion of a project (i.e. the DOE role) or also need to consider the basic IGCC project too, even though the basic project is presumed to already exist and is not part of the DOE funding.

2. It is recommended that DOE attempt to establish reasonable durations for demonstrations it supports.
   a. Assuming DOE prescribes the use of coal project operating economics may be better justified if feedstock switch, perhaps to petcoke, is allowed after an appropriate period of time.
   b. Operating on coal for a period, followed by fuel switch to petcoke, or perhaps biomass and renewable feedstock, could prove helpful to a project, and still provide desirable information and data to DOE.

3. It is recommended that DOE attempt to anticipate how concerns for state and federal regulation consistency and certainty can be handled.
   a. We believe that our Lima Energy Project, for example, will be able to work closely with State officials and successfully craft solutions to issues of concern, but there is uncertainty as to how this effort will mesh with a corresponding federal process.

4. DOE is strongly encouraged to clarify in its pending FOA how NEPA requirements will be handled, especially considering that it expects the IGCC to already be constructed.

Respectfully Submitted,

Dwight N. Lockwood, PE, QEP
Group Vice President
Global Energy, Inc.

COMMONWEALTH OF KENTUCKY
OFFICE OF THE GOVERNOR

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GOVERNOR

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March 3, 2008

VIA E-MAIL: Keith.Miles@NETL.DOE.GOV
Honorable Samuel W. Bodman
United States Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

RE: Response to Request for Information - Restructured FutureGen Project

Dear Secretary Bodman:

I write to provide comments in response to the U.S. Department of Energy's (DOE's) recent Request for Information (RFI) related to the Restructured FutureGen Project. Although Kentucky is disappointed that the FutureGen project in Mattoon, IL is not going forward as planned, we are encouraged by the opportunities afforded under the revised approach. We are grateful for the opportunity to comment.

Kentucky is uniquely positioned to fully participate in the restructured FutureGen program. Kentucky has recently taken a number of actions to reassert its longstanding leadership position in development and demonstration of advanced technology for the clean use of coal and protection of the environment, particularly carbon dioxide emissions control. The efforts of the Commonwealth have been directed both to development of such technologies for the generation of electricity and for production of transportation fuels, chemical feedstocks and substitute natural gas from coal.

If I may, I would like to list some of the reasons why I believe Kentucky is uniquely positioned to contribute to the goals of the restructured FutureGen program.

Location and Geology

- Kentucky's energy resources and geographic location place the Commonwealth at the center of energy production of all types – electricity, transportation fuels, natural gas, renewables – and at the intersection of grids, pipelines, river systems, railroads, and highways vital to energy production and transportation.

- Kentucky's geology offers great opportunity for carbon dioxide utilization in enhanced recovery of oil, natural gas, and coal bed methane and for carbon sequestration in geologic formations including depleted oil and gas reservoirs, unproductive coal seams, various rock strata, and saline aquifers.

Incentives for Energy Independence Act

- A special session of the Kentucky General Assembly in August, 2007, enacted House Bill 1, the Incentives for Energy Independence Act. This omnibus legislation creates substantial financial incentives for coal gasification facilities and renewable energy facilities. It provides funds to the Kentucky Geological Survey to conduct a feasibility study of carbon capture, utilization, and sequestration in Kentucky. The Act also provides increased funds to the Center for Applied Energy Research at the University of Kentucky for applied research, development, and demonstration (RD&D) to assist industry in rapidly incorporating alternative fuel production technologies in plant design and construction, including work on reduction of carbon dioxide from existing coal-fired power plants. The Act also provides continued funding for grants to industry in conducting economic and technical feasibility studies for development and siting of energy projects, including coal gasification facilities in Kentucky.

- Also, we understand that the Kentucky General Assembly will be considering additional incentives, the purpose of which will position Kentucky more favorably for US DOE's restructured FutureGen initiative.

Coal Gasification Research, Development, and Demonstration

- Since its creation in 1974, the Center for Applied Energy Research at the University of Kentucky (CAER) has been a leading center of RD&D relating to advanced coal technologies. CAER's leadership in coal conversion catalysis is known worldwide.

- Several firms are conducting economic and technical feasibility studies for development and siting of coal gasification facilities in Kentucky assisted by the Governor's Office of Energy Policy.

- Since its inception, the Governor's Office of Energy Policy (GOEP) has allocated over $11 million for gasification and carbon management projects.

- GOEP has allocated over $5.5 million in funding for carbon capture and sequestration projects.

- GOEP has allocated approximately $5.6 million for gasification projects.

Carbon Utilization and Sequestration Research

- Regional Carbon Sequestration Partnerships. The Kentucky Geological Survey at the University of Kentucky is a major participant in three of the Department of Energy's Regional Carbon Sequestration Partnerships. These three partnerships reflect Kentucky's unique potential for carbon utilization and sequestration. The partnerships are: Midwest Geologic Sequestration Consortium, Midwest Regional Carbon Sequestration Partnership, and Southeast Regional Carbon Sequestration Partnership.

- Kentucky Consortium for Carbon Storage. The Kentucky Geological Survey and industry have formed the Kentucky Consortium for Carbon Storage to share the cost of carbon utilization and sequestration research and to advance the research through shared facilities, technologies, and knowledge.

Energy Project Facility Site Bank

- The Governor's Office of Energy Policy has identified 19 sites in Eastern and Western Kentucky and characterized these in terms of their suitability for large coal gasification facilities. Identification and characterization of a second set of 20 sites is underway.

I hope that you will agree that Kentucky is uniquely positioned to help the Department of Energy achieve the goals of the restructured FutureGen program. The Commonwealth has a long and proud history of leadership in matters of national energy independence and energy security. We look forward to working with the Department of Energy in the restructured FutureGen program.

Our comments on the restructured approach are spelled out in greater detail in the attached document. Please consider these suggestions in finalizing a restructured approach to FutureGen. I thank you for the opportunity to comment.

Sincerely,

Steven L. Beshear

Attachment

cc: Talina R. Mathews, Ph.D., Executive Director
Governor's Office of Energy Policy

John Hindman, Secretary
Cabinet for Economic Development

Commonwealth of Kentucky
Governor's Office of Energy Policy
Cabinet for Economic Development

Response to Request for Information on the Restructured FutureGen Project

March 3, 2008

Overview:

- Kentucky encourages DOE to expand the scope of eligible projects to include coal gasification projects that convert coal to liquid fuels, substitute natural gas, and chemicals.

- Kentucky also feels that eligible carbon capture projects should include sites at new and existing coal-fired power plants.

- Kentucky commends the DOE on setting a high standard on the requirement to capture 90% of CO_2. However, given the status of this as a demonstration project, to facilitate both IGCC and other technologies (including retrofits of existing facilities), perhaps this number should be determined on a case-by-case basis such that it challenges the limits of the technology under consideration.

- Kentucky encourages DOE to address major issues regarding liability for carbon management, ownership of CO_2 captured/sequestered, and ownership of pore space for sequestration.

- Finally, Kentucky would like to see the restructured FutureGen approach consider other techniques for carbon management (such as algae systems, pipelines, and pre-combustion carbon capture).

Scope of FutureGen Project:

Kentucky encourages the DOE to broaden the focus under the restructured FutureGen approach beyond solely existing (and planned) industries that utilize the Integrated Gasification Combined Cycle (IGCC) process for power generation. Currently, there are very few IGCC projects under development in the United States. For America's energy security and to meet the nation's environmental goals, transportation fuels and pipeline quality synthetic natural gas production that includes sequestration must be developed and demonstrated. Kentucky urges DOE to widen the scope of the restructured FutureGen program to include a broader range of clean coal and power generation technologies. Eligible projects should include sites at existing coal-fired power plants, and coal gasification projects (coal-to-liquids, coal-to-gas, chemicals).

Kentucky recommends that the restructured FutureGen program focus on demonstrating commercial-scale geologic CO_2 storage in several high-capacity basins in the U.S. that are proximal to regions with high concentrations of large stationary sources of CO_2.

Kentucky has identified roughly 40 sites across the Commonwealth that could be suitable for coal gasification facilities. Several are being assessed now. Overall, the Governor's Office of Energy Policy (GOEP) has allocated funding for 20 projects related to coal gasification totaling over $5.2 million.

Consider Different Capture Requirements if Scope is Broadened for Other Technologies:

Kentucky commends the DOE on setting a high standard on the requirement to capture 90% of CO2. While 90% capture would be realistic for a new IGCC plant, if DOE were to widen the scope of the project to include existing conventional coal-fired facilities, 50%-60% may be a more realistic goal.

This is the amount of reduction required from a conventional coal-fired power plant to reduce its emissions to the level of a Natural Gas Combined Cycle (NGCC) power plant (NGCC being the lowest carbon emitting fossil fuel fired plant that's been built). If coal-fired plants are compared to the alternatives that are currently available, NGCC is the best fossil fuel alternative.

Recommend Liability Issues be Addressed Under Restructured Approach:

Kentucky recommends US DOE's restructured FutureGen approach address issues related to liability. There are also significant legal issues related to ownership of the pore space used to sequester CO_2 and the ownership of the CO_2 sequestered. We encourage DOE to address these concerns in the future if this program is to be successful.

Recommend Other Carbon Management Options Be Addressed:

DOE's restructured FutureGen approach focuses on geologic sequestration as the sole means of carbon management. Kentucky suggests that other carbon management options be considered, including methods of conveying CO_2 to market via pipelines and re-use of CO_2.

Geologic storage sites should be chosen with regard to their potential for being scaled up into large storage sites serving multiple facilities; therefore, we recommend that there be no requirement for carbon sequestration to occur at, or adjacent to, the emission sources.

Kentucky also suggests consideration of "pre-combustion" methods of capturing CO_2. One coal-to-gas project under development in Kentucky would do that, using a water-gas shift reaction.

Other Entities Contributing to this Response:

Private Sector:

Kentucky SynGas, LLC

This company is a wholly owned subsidiary of Peabody Energy Corporation, headquartered in St. Louis, Missouri. This company seeks to construct a mine-mouth coal conversion facility to produce substitute natural gas (SNG) in western Kentucky. The project was recently approved for newly-enacted tax incentives (Kentucky Incentives for Energy Independence Act, HB1) by the Kentucky Economic Development Finance Authority (KEDFA). The company lists as partners.

Green River Collieries, LLC

to conduct floodplain and topographical mapping, geotechnical studies, and other assessments to verify that their site is desirable for locating a coal conversion facility. The site under consideration is the

Future Fuels, LLC

This company to develop a project in The company is partnering with to develop a facility to convert coal-derived syngas into electricity and methanol. Future Fuels supports Kentucky's position that the 90% carbon capture requirement maybe not be feasible at this time; Future Fuels recommends that, as a first step, the percentage should be more in the 50%-70% range. There may be an exponential cost relationship as a point of diminishing efficiency returns is reached above 70% carbon capture.

Futhermore, the company advocates including projects with less than 300 MW generation. Future Fuels advocates including any gasification project that produces at least 0.5 to 1.0 million tons of CO_2 per year.

Hitachi Power Systems America, Ltd.

This company has pledged their support for a FutureGen project in Kentucky. They also fully support the Commonwealth's request for the DOE to consider all Clean Coal Technologies, and not just IGCC, in their restructured FutureGen program. The company is a leading technology developer of ultra-efficient coal plants and emissions control equipment. Hitachi Power Systems America, Ltd., have voiced their support for Kentucky's position to expand the scope of the restructured FutureGen project to consider all clean coal technologies that include carbon capture and storage, and not just limit the demonstration to IGCC-CCS.

Global Energy, Inc.

This company, was approved

Though that project was suspended, the company is now considering constructing a coal-to-gas facility at this site to provide SNG to the peaking units at the plant, with the remaining output sold to the natural gas market. This location One unique facet of this project is the company's intention to remove CO_2 "pre-combustion" using a water-gas shift reaction.

Kentucky Gas Recovery Systems, Inc.

This company to study carbon dioxide removal systems. The company recommends a focus on improving power plant efficiencies before considering carbon sequestration. The company advocates using Clean Coal Technology, coupled with improved fixed power plants utilizing more efficient heat engines (Brayton cycle), and altering the traditional engine configurations to achieve much higher thermal efficiencies than traditional Rankine Cycle plants.

Public Sector:

Wayne T. Rutherford, Pike County Judge-Executive

Pike County has pledged to partner with GOEP on any energy project. Given their abundance of coal, natural gas, and biomass, they are well-positioned to contribute to any project that develops Kentucky's energy resources.

Academia:

Kentucky Geological Survey

Dr. James C. Cobb, State Geologist and Director of the KGS, has pledged support for a Kentucky FutureGen project. As a leading participant in the previous FutureGen effort, and a leader in carbon capture and sequestration research via Kentucky Incentives for Energy Independence Act, (HB1), the KGS will be an integral player in any project developed in Kentucky.

Kozo Saito, Ph.D., Univ. of Kentucky, Dept. of Mechanical Engineering

Dr. Saito has been a leading researcher in the areas of emissions control using his patented Vortecone technology. Dr. Saito advocates using abundant, naturally-occurring mineral oxides, such as calcium oxide, to react with CO_2 to produce carbonates and release heat. Theoretically, 56 tons of CaO can absorb 44 tons of CO_2, assuming a reaction efficiency of 80%. By then deploying the Vortecone technology, the carbonates can be captured after they have effectively sequestered the CO_2. Vortecone was developed for the automobile industry to capture paint particulates. It is now commercially deployed in seven (7) Toyota assembly plants. Dr. Saito's research has been supported through grant funding from GOEP.

Wei-Ping Pan, Ph.D., Western Kentucky Univ., Inst. for Combustion Science & Env. Tech.

Dr. Pan, another GOEP grant recipient, has proposed to support a restructured FutureGen project through three research areas: "A Novel Coal-based Chemical Loop Combustion or Gasification for Electricity Generation or Hydrogen (H_2) Generation with Carbon Dioxide (CO_2) Sequestration in the Circulating Fluidized Bed (CFB)"; "Multiple Air Pollutants Emission Control and CO_2 Sequestration in FutureGen Project Using Co-Gasification of Waste Coal and Biomass;" and "Sequestration of CO_2 in FutureGen Project with Simultaneous Production of Green Fertilizer of Ammonia Bicarbonate (NH_4HCO_3)."

Hybrid Power

Technologies

February 29, 2008

Michael F. Keller
Hybrid Power Technologies

United States Department of Energy
c/o Mr. Keith Miles

Subject: Comments on Revised FutureGen

Gentlemen:

We propose altering FutureGens' primary objective (using advanced technology to produce energy from coal) to include achieving dramatic reductions in greenhouse gas emissions using cost effective methods and consistent criteria. We further suggest that FutureGen policies more readily support timely mid-course alterations in response to changing events or new technologies.

Given the uncertain nature of global climate change (the causes of which are not universally accepted) as well as the long timelines associated with such phenomena, we do not believe the US should be rushed into the premature deployment of massive and overly costly greenhouse gas reduction technologies. Specific concerns include:

1. <u>90% CO2 Capture</u>. Greenhouse gas reduction targets should be even-handedly applied to all power plants that use fossil fuels. Modern combined-cycle power plants using fossil natural gas achieve the equivalent of 60 percent reductions in greenhouse gas emissions relative to solid fossil fuel power plants. Such levels are consistent with international goals and aims. To impose more stringent targets (i.e. FutureGen's current 90% reduction target) on coal fired plants is not reasonable and would inflict grossly unnecessary costs on the consumer.

2. <u>Sequestration.</u> Not all regions of the country are amenable to the sequestration of CO2 nor is there a scientific consensus that the technique is a realistic and viable method to permanently capture massive quantities of this greenhouse gas. As currently proposed, the entire success of the restructured FutureGen relies solely on a process that may not be workable.

Prudence and common sense strongly counsel to avoid potentially catastrophic all-or-nothing strategic gambles, particularly given the fluid nature of technology and science.

The ability of alternative technologies to significantly reduce the creation of greenhouse gases should not be discounted. By way of a specific example, the merging of coal and nuclear power (two resources that we posses in abundance) achieves substantial reductions. This hybrid-nuclear technology is briefly described below.

<u>Hybrid-nuclear Power Plant</u>. A high temperature gas reactor (with some 50 years of investment by taxpayers) is married with a coal gasification/combined-cycle plant. Fundamentally, a helium reactor's gas turbine is used to drive the air compressor of the combined-cycle portion of a coal gasification plant while the combustion turbine solely drives a generator. Conventionally, a nuclear turbine drives an electrical generator while a

Hybrid Power Technologies

February 29, 2008

combustion turbine drives a compressor and generator, with the technologies being completely unrelated. This hybrid marriage effectively doubles electrical output, halves the size of the combined-cycle and gasification portions of the facility while nearly halving green-house gas emissions. The net effect is a power plant that is economically competitive with and environmentally superior to new conventional pulverized coal plants. Such an advantage becomes even greater when the hybrid-nuclear plant is compared to supercritical coal as well as integrated gasification combined-cycle power plants that sequester CO2. Enclosure (2) illustrates the hybrid while the Attachment (1) provides an economic and technical summary of the hybrid-nuclear creation.

We suspect other alternative solutions to greenhouse gas emissions also exist or will emerge from industry. The FutureGen program should be sufficiently flexible to quickly capitalize on major breakthroughs when they materialize.

In conclusion, we recommend that (1) greenhouse emission targets be evenhandedly applied to all fossil fired facilities and (2) flexible methods be used to quickly create alternate paths in response to changing events or new technologies

Michael F. Keller

Michael F Keller
President & CEO
Hybrid Power Technologies

Enclosures: (1) DOE Information Request
(2) Hybrid-nuclear Illustration

Attachments: (1) New Beginnings: Hybrid Nuclear Energy, Feb 28, 2008, Michael F. Keller

Hybrid Power Technologies

February 29, 2008

Enclosure (1): DOE Information Request – Comments on Revised FutureGen

Contact Data	Michael F. Keller Hybrid Power Technologies 14713 Woodward Overland Park, Kansas 66223 Phone: 913-681-7687 (home) 913-375-6983 (cell/office) m.keller@hybridpwr.com kellermfk@aol.com
Project: Hybrid-nuclear Power Plant, location open	The hybrid-nuclear technology is in the early stages of development, including formation of consortium members and financial backers. While the underlying technologies exist (e.g. combustion turbines, high temperature gas reactor, coal gasification, combined cycle power plants, etc) adaptations will be required. As such, initial and front end engineering will be required. Discussions with General Atomic in San Diego, Calif and Burns & McDonnell in Kansas City, Mo are in progress and these parties have expressed interest. No major combustion turbine manufacturers have yet been approached. A major heavy vessel manufacturer (Babcock & Wilcox) is aware of the hybrid-nuclear technology. These firms are major and substantial US companies. The inaugural presentation of the technology to the power industry will be at the Electric Power Expo 2008 to be held in Baltimore this May – see www.electricpowerexpo.com, EP08: Track 8 Nuclear Power
Schedule: to be developed	Assistance will be requested from DOE for funding by way of grants or other mechanisms at the appropriate point later this year (2008). Given the national strategic security implications of the hybrid-nuclear technology, an accelerated effort appears in order. With adequate interest and funding, accelerated targets can be met.
DOE Participation: to be developed	Assistance on the level of several million dollars will likely be initially requested, although that is contingent on the degree of support from interested companies and private investors.
Barriers	The hybrid-nuclear technology is patent pending. No real barriers other than those typically encountered upon proposing a major but unconventional breakthrough technology.

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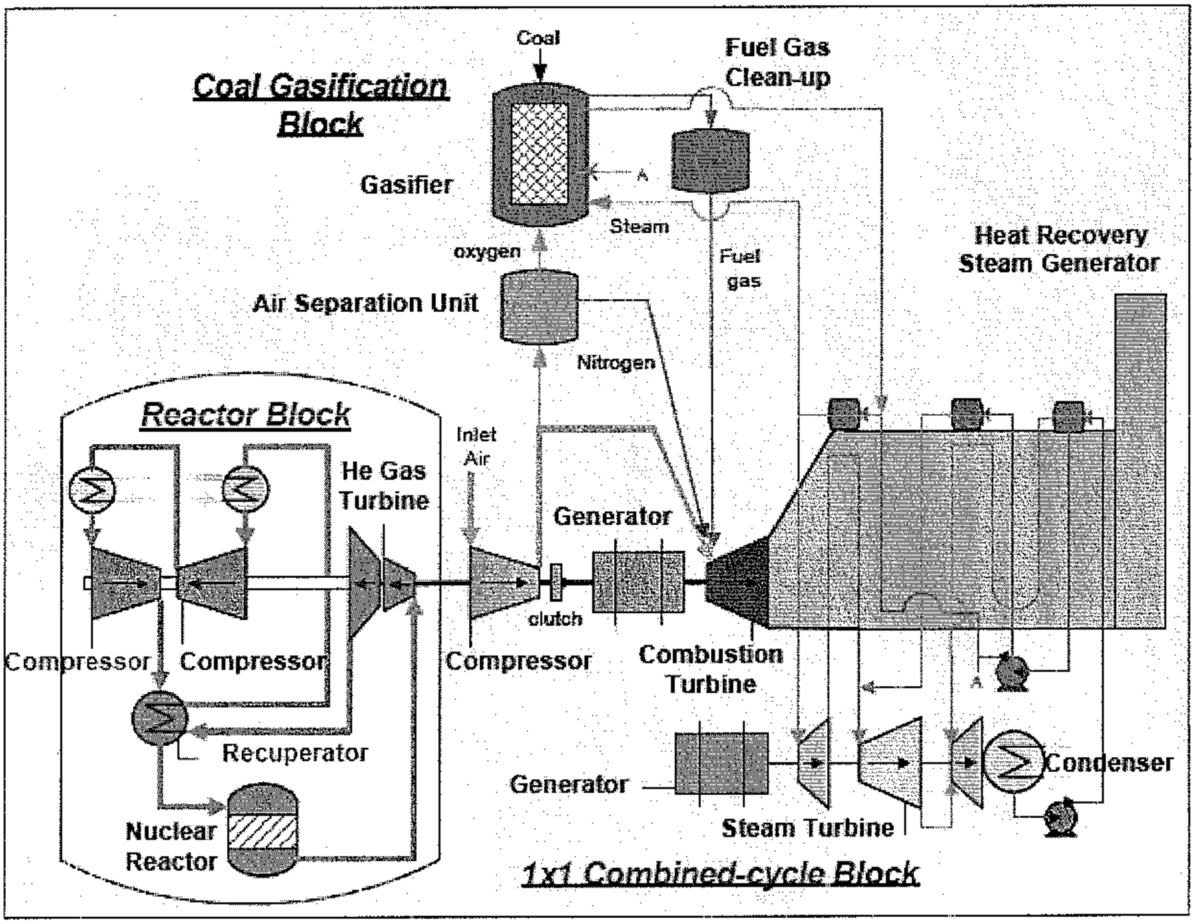
February 29, 2008

Enclosure (2): Hybrid-nuclear/Coal Gasification Power Plant



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NEW BEGINNINGS: HYBRID-NUCLEAR ENERGY

By combining the best of fossil and nuclear energy, this new technology produces low emissions, economical and exceptionally safe power while pointing the way to energy independence.

The world is facing an increasingly vexing problem caused by reality colliding with the desire for environmentally clean, yet inexpensive energy In one corner are coal plants that can generate low-cost power using abundant reserves of coal, but if emissions are unrestrained major health and environmental impacts can occur In another corner are natural gas power plants that can produce energy with relatively low emissions, but the cost to the consumer is becoming increasingly painful Yet another option lies with building nuclear plants that produce emissions-free power, but the capital cost is high and some public unease exists with respect to safety

A major complication is an emerging consensus that burning fossil fuels may be a culprit behind global warming. While intermittent renewable energy supplies (e g wind, solar, etc.) and conservation can help, the undeniable truth is that the vast quantities of power we continuously consume overwhelm the practical capabilities of the "green" sources.

A developing new hybrid technology is aimed directly at using abundant coal supplies to produce reasonably priced and exceptionally safe electrical power, transportation fuels and energy independence with a timely benefit of dramatically reduced emissions, particularly CO_2. These seemingly impossible objectives are met by a unique marriage of nuclear, gas turbine and coal gasification technologies to produce an unexpected result -- the hybrid-nuclear power plant

Several facets of energy production and economics provide keys to understanding the amazing potential of this new family of hybrid energy production plants.

- **Natural Gas.** A modern combustion turbine power plant relies on igniting fuel with compressed air that then spins a turbine attached to an electrical generator. About half the turbine's energy is actually used to compress the air and a steam turbine driven generator is also used to recover energy from the gas turbine's hot exhaust. The "combined-cycle" power plant uses about 50% of the fuel's energy but the high demand for a dwindling domestic supply of natural gas has caused the price of this fuel to nearly triple, with little prospect for reduction. The plants, however, are not particularly expensive and can be rapidly constructed.
- **Coal.** About half of the electrical energy used in the US is produced from coal for which hundreds of years of reserves apparently exist. The power generation process is straightforward (heat from burning coal creates steam that spins a turbine/generator) but generally not particularly efficient. Coal is inexpensive (being a fraction of cost of natural gas) but this comes at the price of emissions, particularly CO_2. While most of these emissions can be sharply reduced, major CO_2 reduction efforts dramatically increase the cost to build and operate the facilities and cause the plant's efficiency to plummet.
- **Coal Gasification.** Major efforts and expenditures are occurring to re-introduce a rather old technology involving turning coal into a gas. Coal gasification involves heating but not actually burning coal, with the synthetic gas produced then used in a combined-cycle power plant. The cost to build such a plant is somewhat higher than a coal plant and emissions are somewhat lower. As with the coal plant, technology can reduce CO_2 emissions but at much increased costs, although not to the level that would occur with a coal plant

Large-scale CO_2 reductions introduce large-scale complications for all fossil fuel based facilities, including troubling issues as to "sequestered" CO_2 removed from the plants. Increasingly strident political opposition is casting doubt on the practical ability to construct new coal and gasification plants that burn an abundant but environmentally challenged fuel

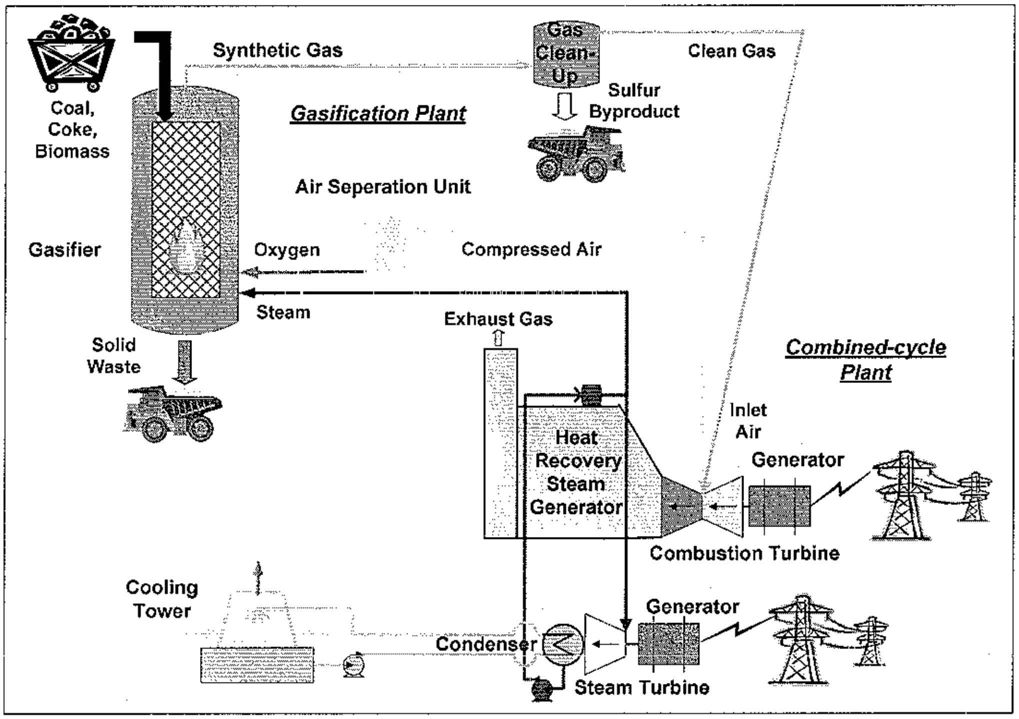


Figure 1: Overview of Coal Gasification

Nuclear Power Conventional nuclear plants are expensive, being perhaps two to three times the cost of comparable coal or gasification plants, with much of this expenditure required to insure the safety of the public. The production process is relatively simple and involves using nuclear heat to create steam that subsequently drives a turbine generator. However, the high cost of the plants (billions of dollars) can introduce potentially high financial risks to owners and investors alike, as history has demonstrated. While the plants are relatively inefficient (~33%), the price of nuclear fuel, as with coal, is a fraction of the cost of natural gas. Nuclear plants normally operate at full power and avoid the daily routine large load swings of the electrical grid. Fossil plants are normally used for such purposes.

For the most part, efforts to construct new nuclear facilities face competitive challenges in most markets.

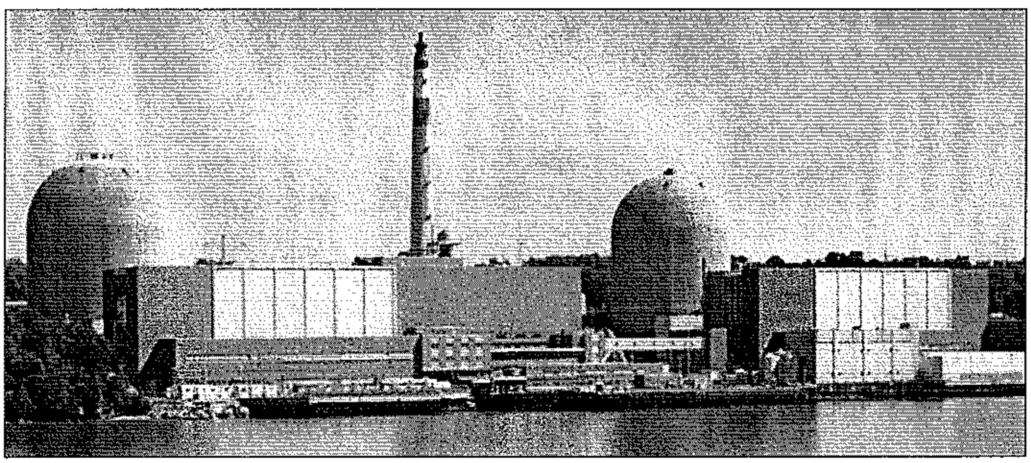


Figure 2: Indian Point Nuclear Power Plant – *courtesy Entergy*

In an effort to reduce the perceived risks associated with nuclear energy, a promising but not new technology relies on using a nuclear reactor to heat helium gas that subsequently drives a turbine generator, with the helium then recycled back through the reactor. The process uses relatively inexpensive nuclear fuel and is efficient - approaching 50%. A key feature (unlike a conventional nuclear plant): one could simply walk away from the facility, the core will not melt and the public remains quite safe. However, this high level of safety comes at a price as the gas reactor can only be about 1/7 the size of the conventional nuclear cousin. The initial investment risk is, however, more manageable as the plant is less costly. Japan and China are operating prototype high temperature gas reactors and South Africa is building a prototype power plant. The U.S. is conducting research and has spent several hundred million dollars on gas reactor technology over the last 25 years.

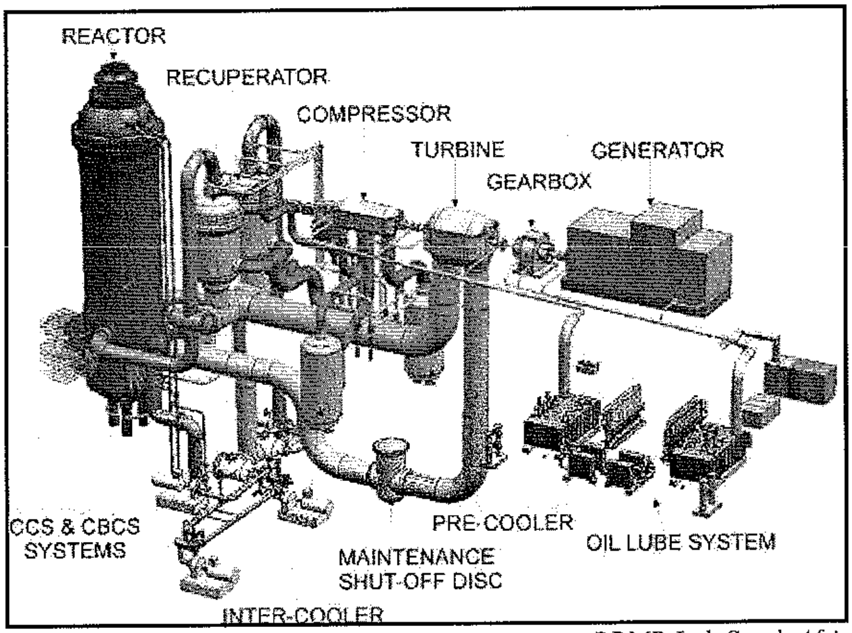


Figure 3: Pebble Bed Modular Reactor – *courtesy PBMR Ltd, South Africa*

Hybrid-nuclear

This unique, patent pending, technology takes advantage of the observation that about half the power produced by a combustion turbine is used to compress air. By using low-cost nuclear fuel and an efficient nuclear system to drive an air compressor instead of a generator, operational costs are greatly reduced and electrical output is dramatically increased. Stated somewhat differently, two combustion turbines would be required to produce the same electrical output as a single hybrid-nuclear unit. The higher capital cost of the efficient hybrid-nuclear reactor is off-set by a lower-cost power generation block and nuclear fuel. The net effect is greatly reduced production costs relative to an equivalent combined-cycle plant that only burns expensive natural gas. A serendipitous environmental benefit: emissions are nearly halved.

Applying the hybrid-nuclear design to coal gasification allows for the emissions-free compression of the air used extensively by both the combustion turbine and gasification plant while simultaneously increasing the overall efficiency of the baseline plant. Also, the size of the gasification and power blocks are about ½ of that otherwise required. These effects yield highly competitive and environmentally friendly hybrid power plants that inherently have significantly lower greenhouse gas emissions than conventional coal or gasification power plants. The reduction is so large that the sequestration of CO_2 is not really necessary.

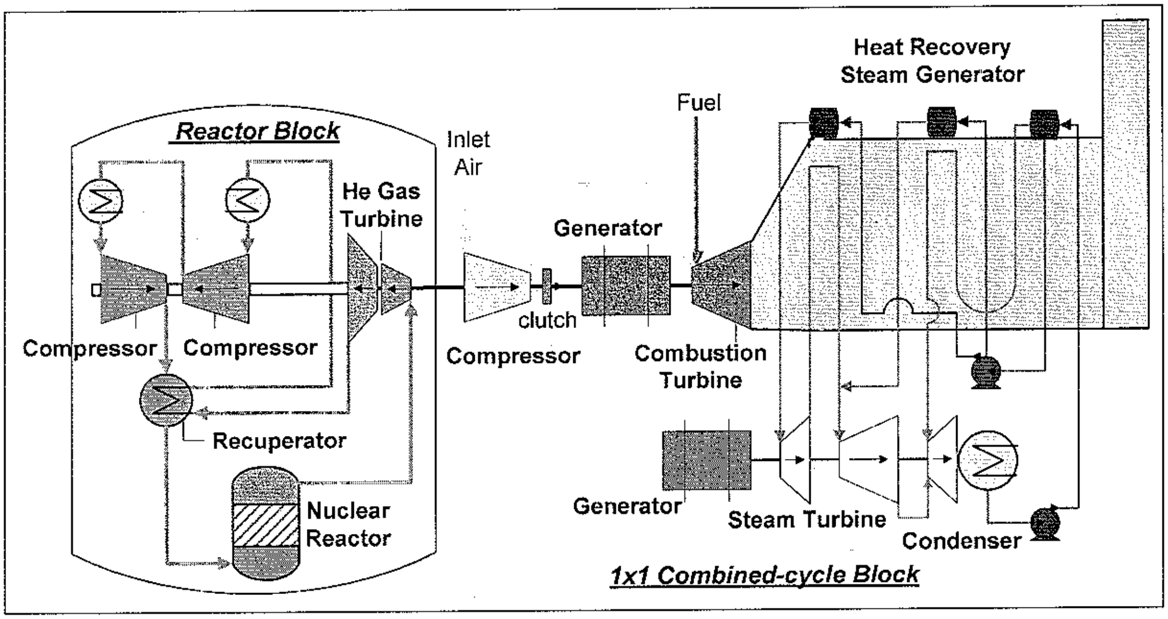


Figure 4: Overview of Hybrid-nuclear Power Plant - Natural Gas Fuel

Major Safety Features

- *Passive cooling, reactor core cannot melt*
- *Reactor located underground*
- *Reactor block isolated from grid and environment, readily handles upsets and accidents*
- *Existing proven, approved materials used*

Benefits

- *Exceptionally low emissions*
- *Compact, modular, cost effective design*
- *Efficient, large load following capability, well suited for wind/solar co-operations*
- *Reasonable fuel costs*

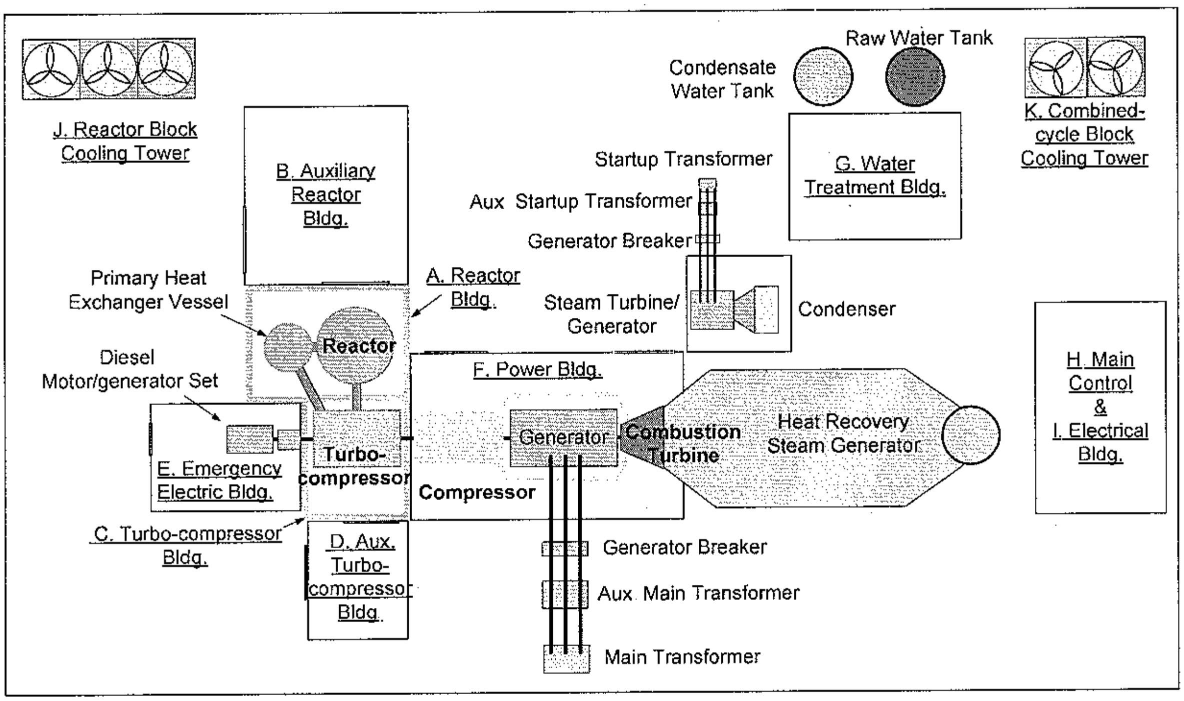


Figure 5: Typical Arrangement - Hybrid-nuclear Power Plant

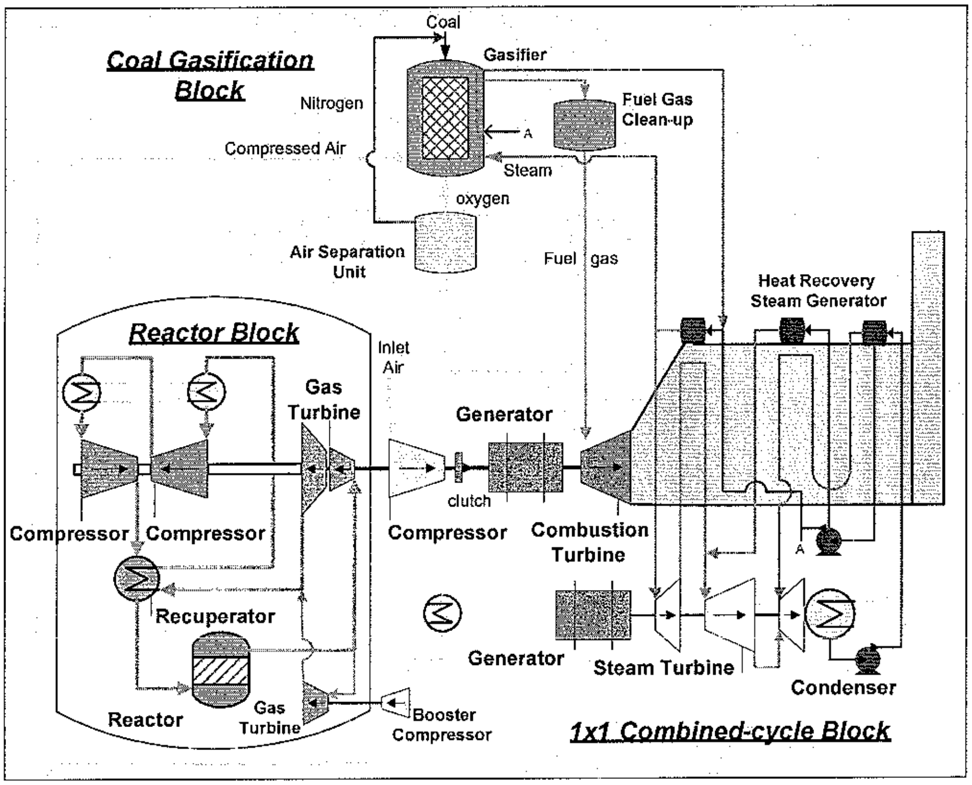


Figure 6: Overview of Hybrid-Nuclear Power Plant - Coal Gas Fuel

Safety

The safety of the Hybrid-nuclear nuclear plant is a significant improvement over conventional nuclear facilities because of the inherent fail-safe heat removal features of the hybrid's small reactor. In addition, substantial safety margins as well as operational flexibility are present because the reactor is not normally connected to a constant speed generator (One should note that conventional nuclear plants are exceptionally safe but high levels of vigilance and associated costs are required to achieve and maintain such a state).

The reactor's silicon carbide fuel is remarkably rugged. Also, extracting weapons grade material is exceptionally difficult and requires expensive and sophisticated equipment.

Environmental

Relative to emissions, the hybrid-nuclear philosophy is straightforward: minimize the production of greenhouse gases by partial use of nuclear power, thereby reducing pollution by a factor of almost two. Such an approach is effective and practical, particularly given the relative absence of proven underground formations to permanently store massive quantities of CO_2. However, the CO_2 sequestration methods envisioned for gasification and coal plants could also be employed by a hybrid-nuclear plant, but at a much lower cost as only about half as much equipment is required. The quantity of CO2 produced is significantly less as well.

Because the hybrid-nuclear reactor is small by conventional standards, spent nuclear fuel is minimal – a few tons ton per year. Unlike a coal plant, ash from a hybrid-nuclear/coal gas plant is an environmentally benign, non-leeching glass-like slag that has many commercial uses. Further, such solid wastes are less than half the hundreds of thousands of tons discharged in a year from a comparable coal or gasification plant.

Water use is a fraction of that used by similarly sized coal or conventional nuclear power plants – such facilities would typically use roughly 10 million gallons or 30 acre-feet per day.

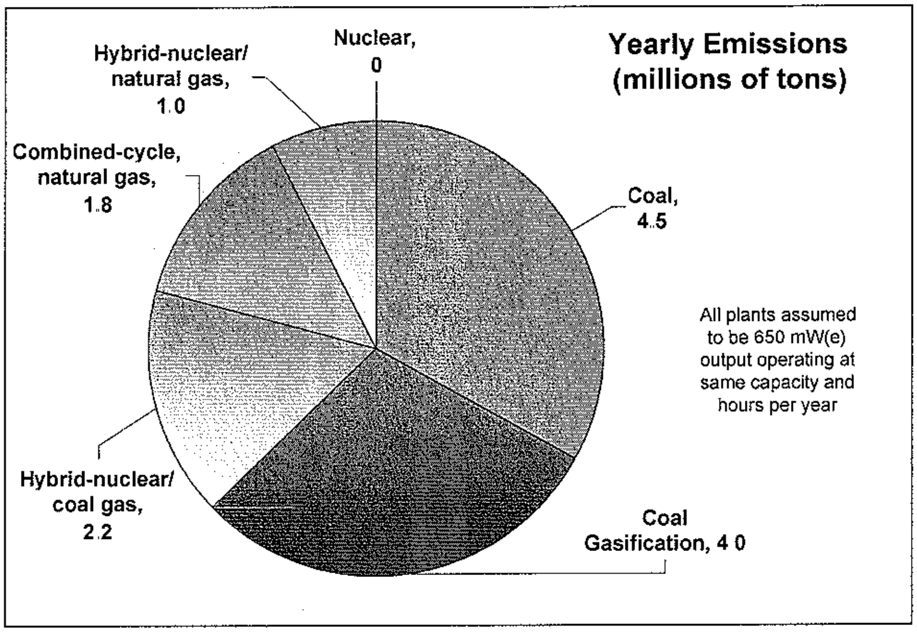


Figure 7: Power Plant Emissions Summary

Economics

In a market driven economy, the cost to produce power is only half the picture The investment must also be profitable. Today's de-regulated electrical market is highly volatile, with large seasonal power price swings - for that matter, large fluctuations exist between early morning and afternoon Include highly volatile fuel prices, such as natural gas, and power plant economics become exceptionally challenging for consumer and investor alike. The hybrid-nuclear financial approach combines stable low-cost coal and nuclear fuels with a reasonably priced power plant to minimize the potentially large risks of the uncertain power market.

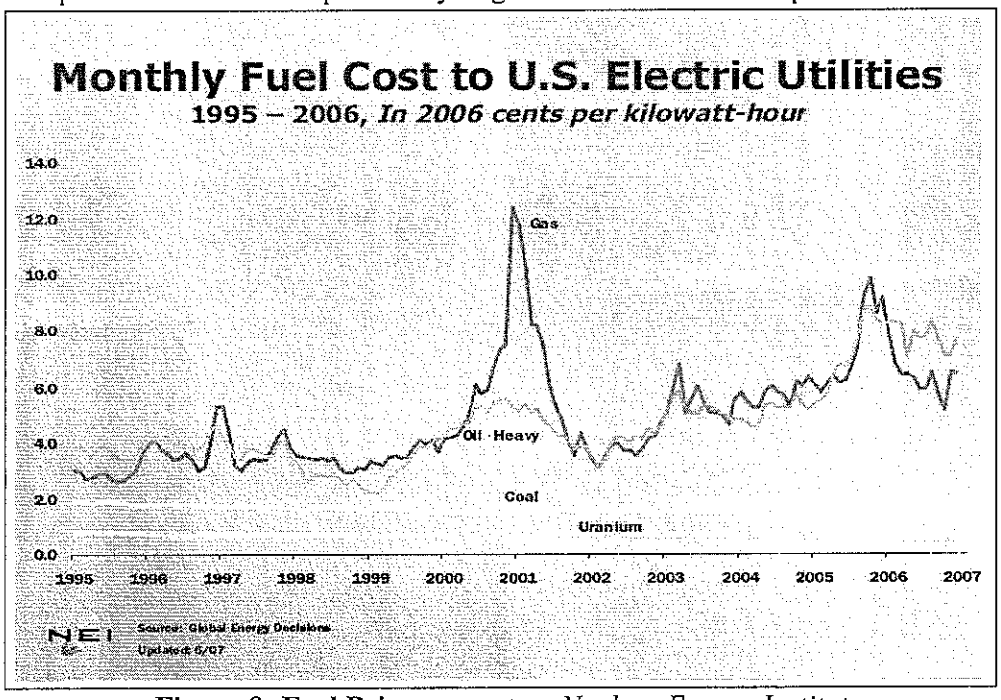


Figure 8: Fuel Prices - *courtesy Nuclear Energy Institute*

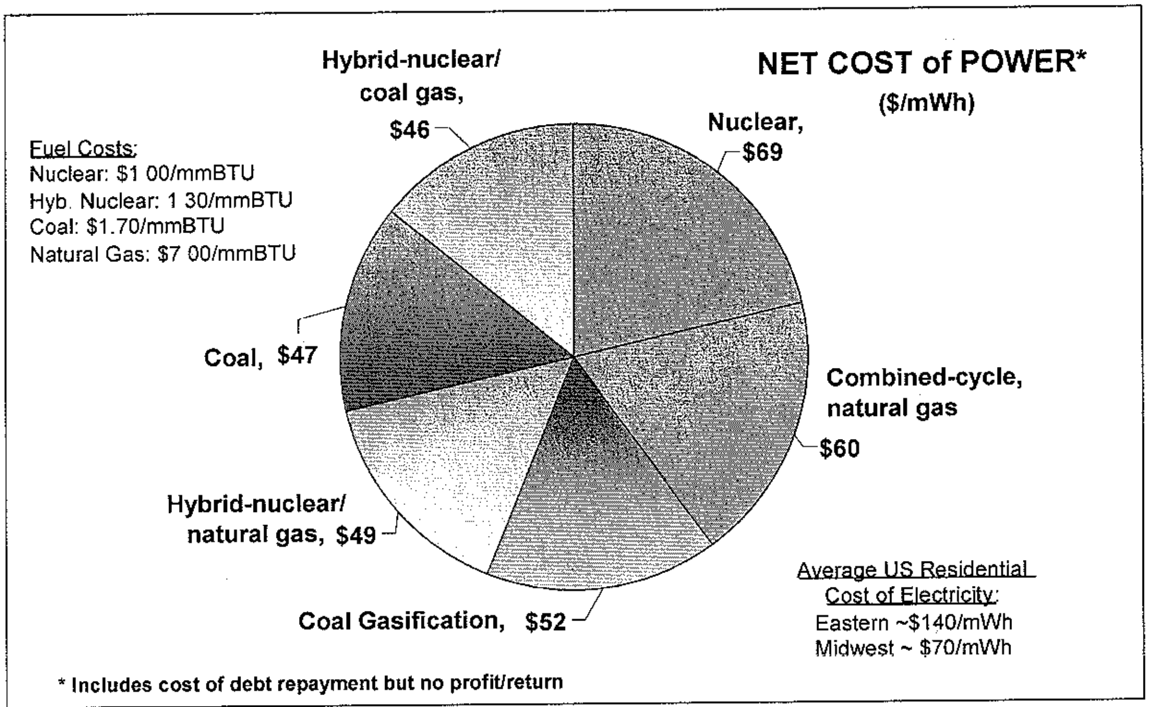


Figure 9: Power Plant Economics – Net Generation Cost

Approximate financial predictions (return on investment before taxes) for new hybrid-nuclear, coal, gasification combined-cycle and nuclear plants that are constructed in the Eastern US and using 2006 electrical grid as well as fuel prices and similar financing assumptions.

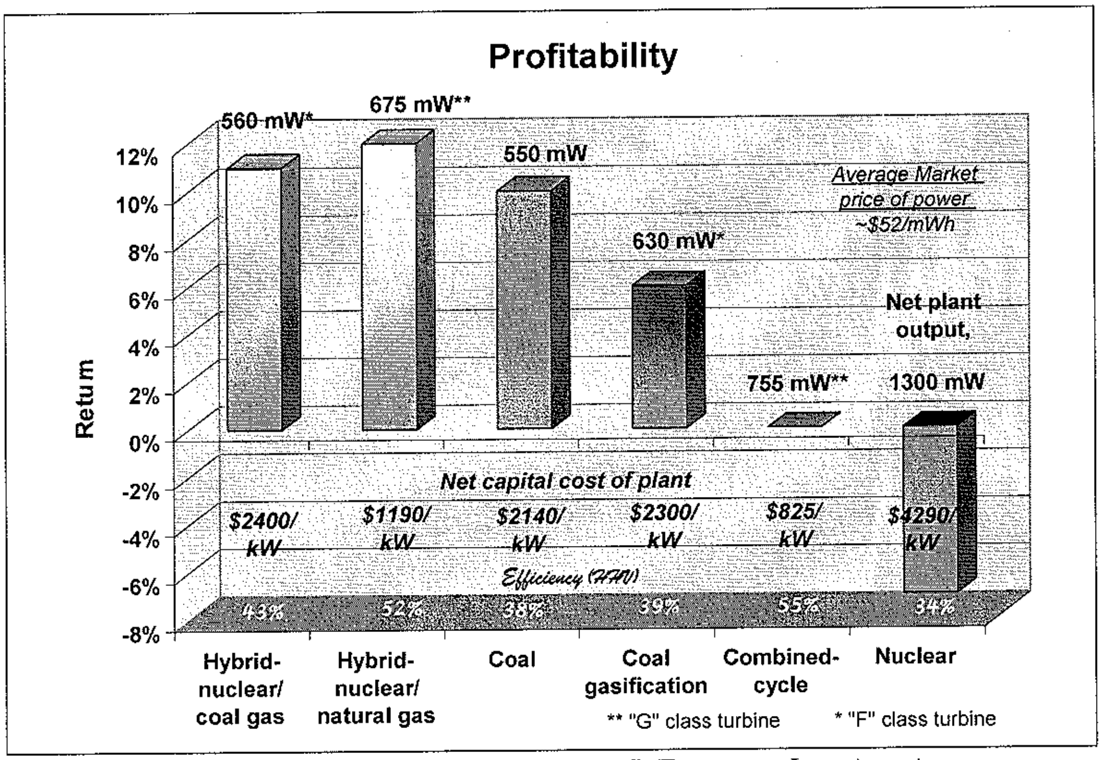


Figure 10: Power Plant Economics – Profit/Return on Investment

The analysis provides an indication of investment potential in a market driven economy.

- The hybrid-nuclear as well as the coal plants achieve comparable positive returns (sub-teens), while that of the gasification plant is somewhat less.
- The combined-cycle plant posts small losses, absent higher market prices for power.
- The nuclear plant profitability is problematic absent relief or higher market prices.

While a fully regulated market is somewhat different, the trends would be similar.

Utilization of the more advanced G/H series combustion turbines with gasification would increase overall efficiency and output several percent and thus yield even better economics (as well as emissions approaching that of combined-cycle power plant in the case of the hybrid).

Energy Storage

Ordinarily, electrical power is difficult to economically store. However, the flexibility of the hybrid-nuclear technology readily supports energy storage, thereby taking advantage of the large market price differentials between day and night power usages.

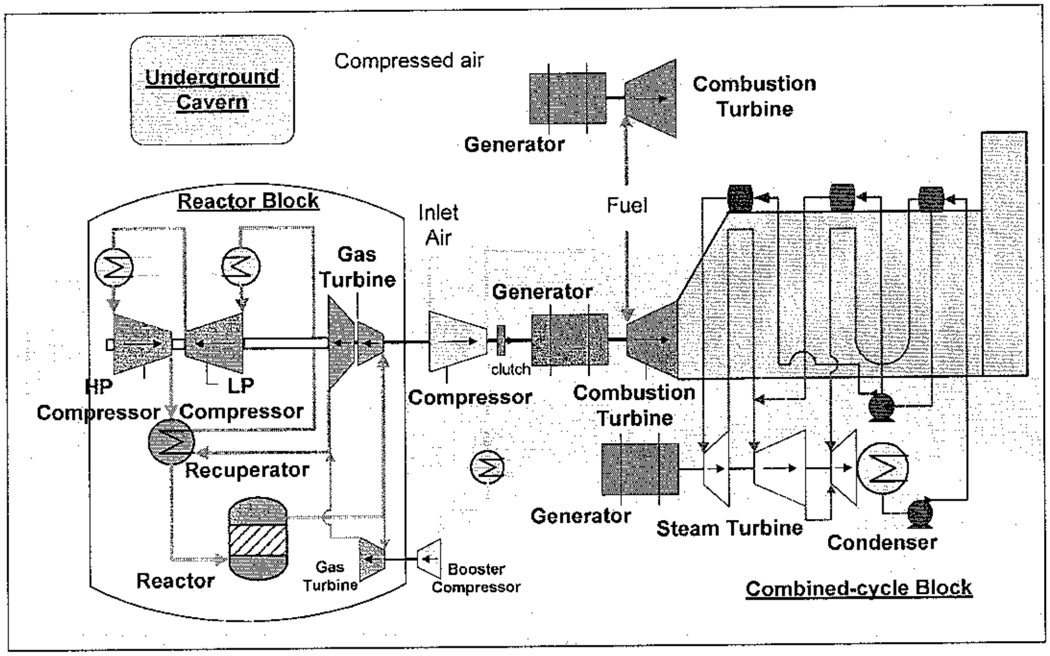


Figure 11: Energy Storage

During off-peak periods, the reactor block driven compressors can divert pressurized air to an underground storage cavern, with the compressed air released for use with a combustion turbine or a combined cycle block during periods of high electrical energy demand. On a comparative basis, the 2x1 hybrid-nuclear facility exhibits approximately double the output of an equivalent conventional 2x1 combined-cycle plant. The hybrid configuration, when coupled with the higher daytime market price for power, should lead to a highly profitable investment.

Co-operations with Renewable Sources

The configuration of a hybrid-nuclear plant allows for a unique integration with renewable solar energy. For those regions with sufficient quantities of solar energy, the hybrid-nuclear plant can use the sun to pre-heat the compressed air fired with the combustion turbine. Fossil fuel use (already significantly reduced) can be further lowered roughly 15%, which when coupled with the much higher market price for power during the day, likely yields a more profitable investment than conventional applications using concentrated solar energy.

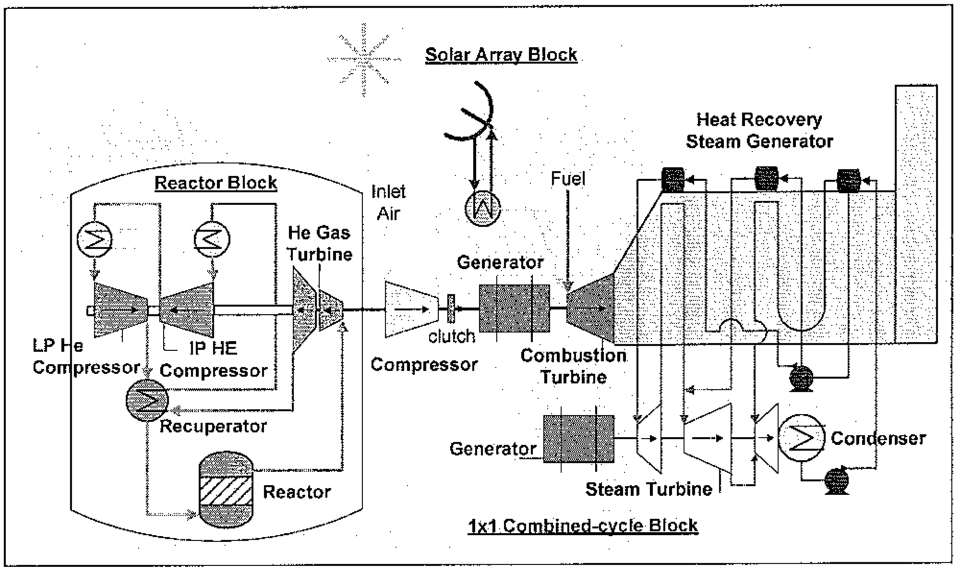


Figure 12: Solar/Hybrid-nuclear

With respect to wind energy, the ability of hybrid-nuclear plants to readily alter output can smooth the power fluctuations normally associated with wind energy farms This joint configuration allows for accruing higher market prices than wind energy can normally command.

Summary

A summary comparison of large-scale energy options yields interesting observations

Table 1: RELATIVE ASSESSMENT – Energy Options

Category	Hybrid-nuclear/ gas	Hybrid-nuclear/coal	Nuclear	Gasification	Coal	Gas
Health & Safety	Best	Average	Good	Sub par	Problems	Average
Emissions	Good	Average	Best	Sub par	Problems	Average
Operating Cost	Sub par	Good	Best	Average	Average	Problems
Capital/Fixed Cost	Good	Sub par	Problems	Average	Average	Best
Net Cost of Energy	Average	Best	Problems	Average	Good	Sub par
Fuel Price Volatility	Sub par	Good	Best	Average	Average	Problems
Profitability	Best	Good	Problems	Average	Average	Sub par
Ranking *(score)*	**1** *(17)*	**2** *(17)*	**3** *(20)*	**5** *(23)*	**6** *(24)*	**4** *(25)*

Scoring: Best =1, good = 2, Average =3, sub par = 4, problems = 5

The hybrid-nuclear technologies build upon the combined-cycle plant's high efficiency and low cost, minimal emissions of nuclear power, absolute safety of the Helium reactor, simplicity of the gas turbine as well as the stable low cost of nuclear and coal fuels while minimizing the disadvantages of the parent technologies. The hybrids offer a more effective solution than any of the single fuel options.

Replacement of older inefficient coal plants (average age of US fleet ~ 30 years) with hybrid-nuclear units would drastically reduce CO2 emissions as well as pollutants such as mercury and sulfur dioxide. International targets for reduction of greenhouse gases would be easily met Widespread use of the hybrid would also significantly reduce the demand on the natural gas.

The Future

Longer range, the hybrid-nuclear technology readily supports a hydrogen economy, but in an unconventional fashion A steam electrolysis block can be integrated with the facility to produce Hydrogen (byproduct) and Oxygen, with the latter used in the coal gasification block The reactor block provides compressed air, heat and steam; the combined-cycle block provides steam and generates power; and the gasification block provides synthetic fuel. Such an integrated process could supply hydrogen for several hundred thousand fuel cell vehicles and enough power for a city. Further, the gasification block could also supply diesel and jet fuel, with emissions significantly less than any existing processes that convert coal into such liquid fuels.

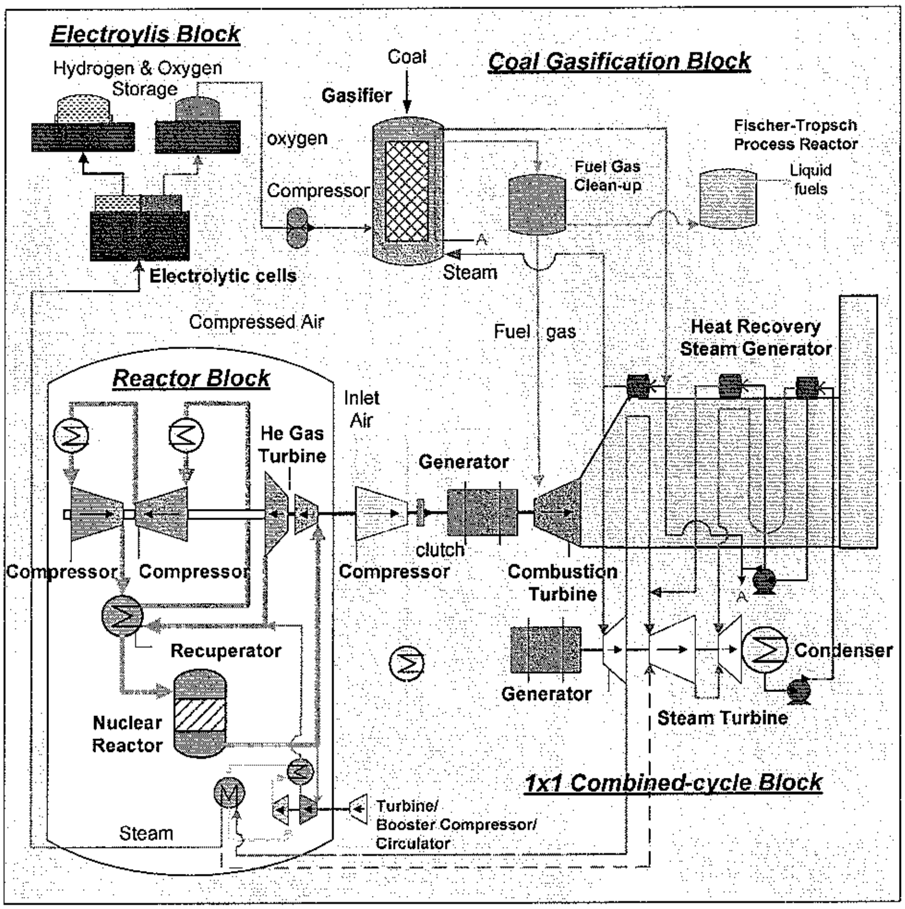


Figure 13: Integrated Energy Production

An economically sustainable and environmentally realistic future would involve:

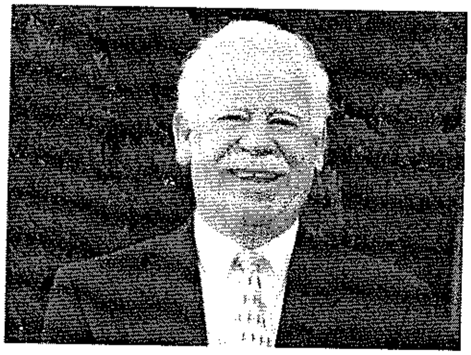
- Extensive conservation of energy and widespread use of renewable sources.
- Prudent use of fossil fuels.
- Conventional nuclear providing base load electrical generation.
- Hybrid-nuclear providing electrical generation and transportation fuels.

Such a strategy would allow us to shape our own energy and economic destinies while providing future generations with an environment significantly better than today's.

Conclusion

The family of hybrid-nuclear technologies offers a safe, practical, simple, clean and cost effective means to provide energy not only for today but for future generations while simultaneously and significantly lessening dependency on volatile foreign energy sources. Because of the unique integration with proven energy production methods, hybrid-nuclear power plants can be fully developed and deployed relatively rapidly.

In the final analysis, we can agonize over our dilemma or move forward with solving the problem. Hybrid-nuclear energy can be a practical and realistic part of the solution.



Hybrid Power Technologies

Michael F. Keller – President and CEO

Hybrid Power Technologies LLC was formed in the summer of 2005 to develop and promote a new family of patent-pending hybrid power plants that use nuclear and fossil fuel sources The hybrid-nuclear facilities are a major technological breakthrough and offer the real possibility of energy independence.

Mr Keller is a veteran of the power industry with extensive and wide-ranging management, business, operations, design, engineering and technical expertise. This in-depth experience has been acquired while working for utilities, plant designers, construction companies and equipment manufacturers Extensive "hands-on" experience with world-wide generating stations, including combined-cycle power plants (oil, gas, propane and liquefied natural gas fired), simple-cycle gas turbines, nuclear and coal power plants as well as steam-methane reformer hydrogen plants

Professional

Bachelor of Science-Nuclear Engineering, University of Virginia
Master of Science-Mechanical Engineering, Rensselaer Polytechnic Institute
Master of Business Administration, St Martin's College
Senior Reactor Operator Site Certificate
Professional Engineer - State of Kansas

Pending US Patent: Hybrid Integrated Energy Production Process

m.keller@hybridpwr.com kellermfk@aol.com 913 375 6983 (cell)

hydrogen energy

March 3, 2008

Mr. Keith Miles
Department of Energy
National Technology Energy Laboratory
626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236-0940

Dear Mr. Miles:

Hydrogen Energy International LLC (HEI) is pleased to provide comments on the Department of Energy's Revised plan for FutureGen. HEI is a joint venture company, 50% of which is held by BP Alternative Energy North America Inc. and 50% by Rio Tinto Hydrogen Energy LLC. HEI was formed to develop a material business through the use of hydrogen fuel for the generation of low carbon power through the conversion of fossil fuels in combination with carbon dioxide capture, transportation and geological storage, including the potential use in enhanced hydrocarbon recovery.

HEI encourages the Department of Energy to pursue the important objectives of providing robust learnings and demonstration of capture and storage for sharing with a broad base of domestic and international stakeholders. We believe that FutureGen as originally proposed remains essential to the energy health and security of the United States, and in tackling the global challenge of climate change. The program will provide important research and application to help ensure we use our most abundant fossil fuels in the cleanest way possible. We further support providing funding to commercial projects in addition to the original FutureGen concept in order to supplement and increase these learnings and to accelerate technology development, demonstration, and deployment

One World Trade Center, Suite 1600, Long Beach, CA 90831-1600 Main (+1) 562-276-1543 Fax (+1) 562-276-1571 www.hydrogenenergy.com

EXPRESSION OF INTEREST

Hydrogen Energy International LLC herewith expresses interest in considering participating in the revised FutureGen initiative.

GENERAL INFORMATION

Project Name: Hydrogen Energy California (HECA)

Point of Contact: Jonathan Briggs

One World Trade Center
Long Beach CA 90831
(562) 276 1510
Jonathan.Briggs@HydrogenEnergy.com

PROJECT DESCRIPTION

The project location will be the San Joaquin Valley, California.

HECA could be an industrial scale plant generating 'low carbon' electricity using hydrogen to fuel a combined-cycle gas turbine. The plant incorporates gasification of solid fuels - bituminous coal from the western United States and/or petroleum coke from California refineries - to provide a hydrogen-rich fuel for power generation and CO_2 for enhanced oil recovery and sequestration.

Key plant design features could include the following:

- Syngas generation using GE Quench gasification technology with a multiple gasifier configuration to enhance plant reliability.
- Hydrogen-fuelled GE Frame 7FB gas turbine in combined cycle configuration generating a nominal gross power output of 390 MW at average ambient conditions.
- The gasification plant will be designed to achieve a carbon capture target of approximately 90%wt of the carbon present in the coal/coke feed during steady state operations.

- Approximately 2.5 million tones per year of captured CO_2 will be delivered by pipeline to a very large oil field for use in Enhanced Oil Recovery (EOR) and sequestration.
- Plant siting and facilities layout will ensure initial development does not preclude future expansion.

We are also actively evaluating a number of options to build on this initial development to supply additional low carbon power to California consumers.

PROJECT DEVELOPMENT STATUS

HECA and its affiliated entities engaged in project development for the best part of two years, and benefits from a clear delineation of technology, basis of design and scale, and site required for the purpose of pursuing local permits ahead of construction. The necessary frameworks have also been established, together with a local outreach and stakeholder engagement process. Front End Engineering Design is expected in 2009. Plant operations are expected to commence in 4Q 2014.

Hydrogen Energy subsidiaries employ some one hundred people, and an equivalent number of contractors, dedicated to pursuing the development of low-carbon power with CCS, including thirteen permanent employees working full time to develop the California project. In addition, this project has engaged Fluor, Jacobs Engineering, and Roberts and Schaefer to provide engineering services, URS to develop the Project's permit and a number of other firms to provide specialist engineering and consultative services.

The HECA team has and will continue to draw on the extensive body of knowledge developed by previous hydrogen energy and CCS project development efforts at Peterhead, Scotland - the world's only hydrogen power plant with CCS to be fully permitted - Carson, California as well as a Hydrogen Energy affiliate's recently announced project in Abu Dhabi.

PROJECT PROPONENTS

HEI is a joint venture company, 50% of which is held by BP Alternative Energy North America Inc. and 50% by Rio Tinto Hydrogen Energy LLC. HEI was formed to develop a material business through the use of hydrogen fuel for the generation of low carbon power through the conversion of fossil fuels in combination with carbon dioxide capture, transportation and geological storage, including the potential use in enhanced hydrocarbon recovery.

Rio Tinto is a leading international mining group. Its parent company, headquartered in the UK, combines Rio Tinto plc, a London-listed public company, and Rio Tinto Limited, which is listed on the Australian Stock Exchange (collectively, the "Group") The Group finds, mines and processes the earth's mineral resources - metals and minerals essential for making thousands of everyday products that meet society's needs and contribute to improved living standards. The Group's major products include aluminum, copper, diamonds, energy products (coal and uranium), gold, industrial minerals (borates, titanium dioxide, salt and talc), and iron ore. Its activities span the world but are strongly represented in Australia and North America. There are also significant businesses in South America, Asia, Europe and southern Africa.

BP and its subsidiaries are one of the world's largest oil and gas companies with operations in more than 100 countries across six continents. The company's main businesses are exploration and production of oil and gas; refining, manufacturing and marketing of oil products and petrochemicals; transportation and marketing of natural gas; and a growing business in renewable and low-carbon power, BP Alternative Energy. BP's renewable and low-carbon interests combined in BP Alternative Energy include: BP Solar; the company's fast growing interests in wind power; gas-fired power generation; biofuels, distributed energy; coal conversion and BP's interest in Hydrogen Energy.

PROJECT SCHEDULE

As discussed above, HECA expects to commence operations in 4Q 2014, which exceeds DOE's schedule aspirations for plant operations. However, as more fully discussed below, HECA believes that storage of CO_2 in a saline formation by 2015 is likely to be found impractical and that CO_2 injection into an oil and gas formation is likely to provide a preferable storage option that is both proven and commercially viable.

ESTIMATED DOE CONTRIBUTION

We expect early CCS projects to require a mixture of incentives to cover the capital and operating cost premium associated with the technology. As part of the required mixture of incentives and other revenue streams such as EOR value we expect, based on current estimates, a contribution from DOE of approximately $300-500 million for carbon capture and transportation facilities could help enable the project to proceed.

Note this does not include the cost to identify, delineate and develop a saline formation with assured storage volume and sealing mechanisms. Although we will be looking to develop saline formation options, we believe that these costs are highly location-specific, forgo the capture of any EOR value to supprt project costs, and are likely to provide additional challenge toward a successful project.

BARRIERS TO EFFECTIVENESS

The primary barrier to the effectiveness of the proposed restructured approach to the FutureGen initiative is the requirement to store CO_2 in saline formations by 2015. Planning studies conducted by HEI indicate 7-10 years should be allowed in a project's schedule to identify, delineate, characterize and develop a saline formation for sequestration. The amount of work required for saline formation exploration, appraisal and development is broadly analogous to oil and gas exploration and production programs. This is not widely appreciated and so may not be seen as a barrier by many project developers.

Depending on the costs associated with sequestration in saline formations, Hydrogen Energy may determine that the project is more economically viable with a CO_2 revenue stream for enhanced oil recovery purposes. We know that DOE recognizes that projects have location-specific options for storage formations. We encourage the Department to structure its program to include CCS projects within oil and gas formations with the potential for enhanced hydrocarbon recovery. Supporting multiple projects with differing storage formation characteristics can enhance the demonstration of CCS technology and spur broader development of IGCC/CCS projects.

Another potential barrier to effectiveness of DOE's restructured FutureGen initiative is the mechanism used to provide financial support to nominated projects. HE-CA1 believes DOE's financial support mechanism must be fully funded, not contingent on annual approvals, and schedule-certain so that developers of nominated projects can include the DOE funding benefit in their economic evaluations.

ADDITIONAL COMMENTS ON PROPOSED RESTRUCTURE OF FUTUREGEN

HEI would like to emphasize the critical need for significant levels of carbon capture in order for advanced coal technology to serve as an effective climate mitigation measure. We agree with DOE's steadfast goal in supporting projects with a high level of capture, at a minimum of 80%. We firmly believe that a high capture rate is necessary if advanced coal technology projects are to outperform natural gas and make a meaningful contribution to tackling the impact of climate change HEI is committed to demonstrating these higher levels of capture and, indeed, as noted, the project described herein will be designed at steady state to achieve a capture rate of approximately 90%.

We also request that the DOE will include petroleum coke and coal/petcoke blends as feedstocks in its FutureGen and other advanced coal technology demonstration programs. It is important to include petcoke, a coal-like substance, which is an abundant byproduct of petroleum refining and has enormous economic and energy potential for demonstrating advanced coal technology.

We also note that CCS projects require a wide range of skills for successful implementation and are likely to involve collaboration between companies with diverse expertise, including transport and storage. The precise commercial structures of projects will remain a matter for the parties but may well involve a certain degree of commercial separation and focus by companies on their areas of core expertise.

Furthermore, we feel obliged to comment that the current level of funding proposed for the Revised FutureGen program is simply not sufficient to support multiple projects. We urge DOE to manage expectations within the Department, Congress, and other stakeholders, that multiple projects will ultimately require additional funds. We urge the Department to continue pursuing funding programs that will allow visionary companies with robust capabilities, such as Hydrogen Energy International, to develop IGCC/CCS projects in the U.S., such as that planned for California, and additional locations in the future.

Again, we appreciate the opportunity to comment and provide our expression of interest in the Revised FutureGen program. The material in this letter describing the project description, project development status, project schedule and estimated DOE contribution is Business Confidential Information.

Sincerely,

Jonathan Briggs
Regional Director, Americas
Hydrogen Energy International, LLC

Rod Blagojevich
Governor

Jack Lavin
Director

March 3, 2008

State of Illinois Comments on Request for Information -- U.S. Department of Energy Restructuring Plan for Carbon Capture On Commercial-scale Coal Gasification Facilities

Introduction

Illinois is a leading U.S. coal producing state with an indisputable commitment to development of clean-coal technology, particularly in the area of capture and sequestration (CCS) of carbon dioxide (CO2). The state has worked for five years on initiatives related to CCS, including two years of work in support of two finalist sites for the original FutureGen project. In addition, Illinois is one of only two states in the nation that have enacted legislation to limit the liability of entities injecting CO2 into underground saline reservoirs.

On behalf of Illinois Governor Rod Blagojevich, the Illinois Department of Commerce and Economic Opportunity has reviewed the U.S. Department of Energy's recent solicitation of parties, projects and sites to be considered for funding under DOE's post-FutureGen initiative. Few stakeholders have more insight, or keener interest in the outcome of this process than the State of Illinois. **We urge the Department of Energy to recognize the inherent shortcomings of its post-FutureGen plan and abandon it. DOE instead should negotiate a reasonable cost-sharing agreement with the FutureGen Alliance. FutureGen must proceed without further delay, as originally structured, at the highly qualified site chosen at Mattoon, Illinois.**

The state's position may not be unexpected, given the investment the State of Illinois has made in the project. We recognize that our path to energy security and a better environment for our children is inextricably dependent on sound federal energy policy and federal support for an aggressive and diverse clean coal research and development program. FutureGen should not be the program in its entirety, but should be at the heart of the program. Therefore, Illinois, its fellow coal states and the world will be losers under the proposed restructuring of the DOE's Integrated (Coal) Gasification Combined Cycle (IGCC)-CCS initiative. The reasons for this judgment will be explored in more detail focusing on the following critical areas:

- Timeliness
- Commercial viability
- International impact
- Energy policy credibility

Comments on Areas of Critical Concern

1. Timeliness

The Department's untimely abandonment of its partnership on the proposed FutureGen at Mattoon project represents a valuable opportunity squandered. The abrupt decision came at the end of a two-year-long site selection process whose timeframes, by and large, were dictated by DOE and requirements related to the National Energy Policy Act (NEPA). The attempt to halt FutureGen also came as the project's developers were about to launch three-dimensional seismic testing of the area around the Mattoon site It also came as the developers were about apply for an Illinois Environmental Protection Agency permit to drill a mile-deep characterization well to expedite the project.

The two-year period mentioned above also was marked by sharply increasing pressure from several sectors to explore technological solutions to greenhouse gas emissions caused by coal-fueled electric generation facilities.

The process of advancing FutureGen to the brink of site selection was thorough. Considerable public, political and institutional support was generated for the project at all four finalist sites. In addition, support for the an Illinois site was demonstrated by governors and other policy leaders of nine states representing about three-fourths of the coal tonnage mined in the U.S. and more than half of the electricity generated from coal [1]

The alternative plan outlined by DOE, along with comments from Energy Secretary Samuel Bodman, point to project selection no earlier than December 2008 That date, the Secretary has said, most likely would be achievable **only** if a project proponent used one of the four original finalist sites for which NEPA-EIS work had been completed.

The best guide for timing is the most recent experience with DOE and the NEPA process for a single project site, coupled with difficulties incorporating pioneering technology to inject and store CO2. Under such a scenario, the Secretary's goal of completing a project and initiating CCS by 2015 is extremely ambitious, even for a single configuration and location. DOE's stated time line for multiple sites and configurations is virtually unachievable. Further delay is likely to occur with a new Administration taking office in January.[2]

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[1] The states: Illinois, Indiana Kentucky, Michigan. Ohio. Pennsylvania. West Virginia Wisconsin and Wyoming.

[2] There is no way we will get anything before 2012 on the same type of scale *(as FutureGen) and I m not convinced that anybody's going to be able to do it cheaper than FutureGen" - Howard Herzog of the MIT Laboratory for Energy and the Environment, quoted in Jan 13 2008, issue of *Scientific American*

Even with a December 2008 project selection date, the earliest a Draft Environmental Impact Statement could be completed is the fourth quarter of 2009 Again, under the most optimistic circumstances, an additional six to nine months would be consumed by publication of the findings, public hearings, public comment periods and review/response to those comments. This would allow project selection to occur no earlier than the second or third quarter of 2010. A more realistic estimate for project selection is mid-2011. Additional time would be consumed for permitting and final site characterization work, as well as any legislative initiatives related to ownership and liability for damages related to CO2 injection.

The earliest a new project could be operational is likely to be 2016. FutureGen at Mattoon can be operational in 2012. The reprogramming of FutureGen will delay important technology development by three years or more and risk further cost escalation while the world waits for a solution to the most important issue facing the world's environment and the future of our children.

CONCLUSION: Using reasonable scenarios, five years or more could be lost in pursuing demonstration of CCS from an IGCC plant, if such a facility is ever built. In the absence of mandatory CO2 reduction legislation, private sector sponsors of commercially viable IGCC plants will be unwilling to assent to project delays, risking continued cost increases in the interim. As a result, demonstration IGCC-CCS plants in the U.S. will become unaffordable, and the U.S. no longer will control its own destiny in pursuit of near-zero emissions coal-to-electricity technology development.

2. Commercial viability

The Department of Energy's RFI makes broad, and in many cases faulty assumptions about the technical feasibility and commercial viability of stand-alone IGCC power plants. The most serious flaw in the DOE analysis is that recent project delays and cancellations are due solely to uncertainty about future CCS requirements

Only two electric plants in the U.S today use IGCC technology – the Cinergy/Duke Energy Wabash River Station in Indiana and Tampa Electric's Polk Station in Florida. Both were built more than a decade ago, both with heavy government subsidies. Today, neither is being run on a straight feedstock of coal.[3] A third attempt to demonstrate IGCC in the U.S., the Piñon Pine Project in Nevada, never reached steady-state operations. Despite this track record, DOE asserts that coal-to-IGCC technology is suddenly mature, despite the fact that there has not been a single commercial-scale U.S demonstration project in nearly 15 years.

The DOE also wrongly blames the shelving and cancellation of IGCC projects solely on uncertainty about forthcoming C02 regulations. In doing so, the agency ignores obstacles such as

[3] Wabash River now operates on petroleum coke Polk Station burns a combination of coal, petroleum coke and biomass

facility cost and power marketability that have prevented commercial-scale deployment of an IGCC fleet for years. In fact, several IGCC projects, including a plant in Illinois, have received air permits to proceed with construction without a carbon management plan. Typically, such projects have been slowed or halted due to cost estimates forecast 30-50 percent above targets, along with risks associated with building commercially unproven technology. Recent uncertainty over carbon regulation has been cited as a third stumbling block

A final flaw in the Department of Energy's counterproposal is the naïve assumption that projects can succeed with 100 percent federal funding of the facility's back-end CCS system, but without major financial incentives for the power side of the project. This means DOE expects a private-sector utility to build a plant that already is unaffordable and, to further compound the problem, "de-rate" that facility's efficiency by as much as 20 percent with the parasitic power load of a back-end, 90 percent-capture CCS system.

The FutureGen initiative was proposed and advanced to demonstrate ways to reduce risks while field-testing and adapting the best available IGCC technology The project's success would foster widespread investment in new IGCC-CCS plants. However, given the obstacles and uncertainties cited above, the IGCC facilities now envisioned by DOE can be built only in states where the electric rate structure accommodates the pass-through to electric consumers of higher per-kilowatt prices due to inflation and other risks associated with demonstrating unproven technology. While there may be widespread benefits from using these facilities as laboratories for CCS technologies, significant costs of this trial-and-error process will fall unfairly on electric customers of a select group of states.[4]

A more responsible alternative remains available by proceeding with the original integrated IGCC-CCS plan of FutureGen. It would receive sufficient federal support to build, operate and demonstrate technologies for a broad corporate and international clientele while, as early as possible. At the same time, it begin to build public support for the concept of near-zero emissions coal power and safe storage of CO2 in widely available underground formations.

CONCLUSION: Commercially competitive plants utilizing IGCC technology can not and will not be built without substantial government subsidy beyond the CCS component. The Department of Energy is egregiously unrealistic in asserting that IGCC technology has reached an off-the-shelf level of maturity. It is equally unrealistic to believe DOE can launch a multi-site carbon capture initiative for DOE's estimated $1.3 billion price tag. If these plants can be built at all to provide a platform to demonstrate CCS technologies, they will be built in states whose electric consumers would be forced to assume a disproportionate share of the cost burden.

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[4] American Electric Power's proposal to build a commercial-scale IGCC project in Ohio has been challenged in court by the Ohio Office of Consumer Counsel, representing the state's residential electric customers The lawsuit asserts that AEP had not proven an IGCC plant would be the lowest cost alternative for meeting the energy needs of AEP customers in the state of Ohio.

3. International significance

One cannot underestimate the importance of the word in the phrase "global climate change." Reducing greenhouse gas emissions is a global concern in need of solutions without borders. CCS has been identified by the U.N. Intergovernmental Panel on Climate Change (IPCC) as a most critical technology for reducing CO2 emissions

When launching the FutureGen initiative in 2003, DOE highlighted the advantages of a project co-sponsored by coal producers and users worldwide. The FutureGen Alliance responded, with the help of Alliance members, DOE and the U.S. State Department, to organize and grow what has become a 13-member international consortium of private sector partners with representation on six continents.[5] As a group they envelop the globe and represent the diversity of industrial resources and corporate cultures.

In attempting to cancel the project upon selection of an Illinois site, Secretary Bodman announced a counterproposal that not only delays CCS implementation by as much as five years, but also moves ahead with a U.S.-only project. Bodman essentially said the U.S. would proceed with a myopic, go-it-alone strategy he termed "an all-around better investment for Americans."

Even as a coal state located in the middle of North America, Illinois recognizes the short-sightedness of this view. The appeal of the FutureGen initiative, in no small measure, is its scope and vision. The Department of Energy's hastily constructed Plan B, to fund "back end" CCS systems for isolated IGCC projects scattered around the U.S., lacks the vision that is critical to correct global climate change. In addition, the U.S. will have done nothing to capitalize on the substantial investment to date by private industry and international partners.

DOE all but admits this limitation for the scope it has outlined for Plan B. The agency's RFI states that the purpose of the solicitation is "to better reflect the current and future needs of the U.S. coal-fired power sector." Only the briefest mention of international impact is contained at the end of the same document section, where DOE adds, gratuitously: "... the revised FutureGen is expected to provide for international coordination designed to benefit all participants interested in future deployment of coal-fired electric power plants."

COMMENT: By moving swiftly back to its original vision for FutureGen, the U.S. Department of Energy can regain for the U.S. the initiative in developing effective CCS technology. International interest in the FutureGen at Mattoon project is not yet lost, and foreign participation will likely increase if DOE does not turn its back on its global responsibility and allow IGCC-CCS technology to be developed on foreign soil.

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[5] Alliance members include the Huaneng Group (China), Anglo American Power (United Kingdom) BHP Billiton (Australia) and Xstrata Coal (Australia). In addition, Anglo American has operations in Africa. Australia and South America. The parent of E.ON US has offices in Germany and Argentina; and Xstrata Coal has operations in Australia South Africa and Columbia

4. Government credibility

By any measure, the Department of Energy's attempt to scrap FutureGen at the 11th hour has created a cloud of uncertainty over the agency's credibility as a project partner. This action also has also brought into question DOE's sincerity to carry out President Bush's pledge to move ahead effectively on CCS and other clean coal technology efforts.

In its move to structure, DOE misled its project partners, indicating as recently as early December that FutureGen at Mattoon was on track. This late-in-the-process reassurance came in numerous forms:

- Completion by DOE of a rigorous site review process that included outpourings of community support at public hearing venues such as Riddle Elementary School in Mattoon, the Tuscola Community Center and two similar locations in Texas
- Issuance by DOE of a Final Environmental Impact Statement on Nov. 9, 2007, and publication of the Final EIS on Nov. 17
- A November 30 letter from Secretary Bodman to U.S. Rep. Timothy Johnson of Illinois indicating that a Record of Decision approving the finalist sites would be entered by the end of December
- Selection of Mattoon as the host site at FutureGen Alliance board meeting in early December
- Showcasing of FutureGen by DOE at its exhibit at a December 10-13 at a major power industry conference in New Orleans

Only days later, members of the Illinois congressional delegation were told the deal was off – that DOE would not seek FutureGen funding in its upcoming budget request and that it would issue what became the January 30 RFI seeking multiple IGCC-CCS sites. One DOE executive, in fact, referred to FutureGen as "building Disneyland in a swamp" at Mattoon. He later issued an apology.

In its current budget request, DOE is asking Congress for $407 million to increase the efficiency of burning coal, according to the *Scientific American*, as well as to research how to burn coal most efficiently. In addition, DOE is requesting $241 million to demonstrate CCS technologies. The cost is at least $900 million less than DOE said it would have cost to complete FutureGen.[6]

[6] Scientific American Jan 13 2007

DOE is largely ignoring the damage a minimum five-year delay that restructuring will have on the future of the U S. coal industry and progress on capturing greenhouse gases Meanwhile, DOE is advancing a multi-site CCS alternative based on flawed economic reasoning, and with virtually no recognition of substantial international participation to date. Finally, DOE is asking for a new set of corporate partners to trust DOE while subjecting their IGCC projects to costly delay and significantly decreased efficiency.

As Secretary Bodman recently told Congress, the shortest path to a successful IGCC-CCS demonstration project is through sites in Mattoon and Tuscola in Illinois and Jewett and Odessa in Texas. These are the only sites for which costly and time-consuming EIS studies been done. Only in Illinois and Texas have laws been enacted to assume public liability for injected CO2. These are the only sites that could be reasonable to expect an IGCC-CCS project to achieve DOE's time frames.

COMMENT: To regain its credibility and move FutureGen forward on a meaningful time line, the Department of Energy must acknowledge the qualifications of the two Texas and two Illinois sites by issuing its pending Record of Decision.

Summary

Upon review of the Department of Energy's solicitation of interest issued Jan. 30, 2008, the state of Illinois is submitting these comments highlighting the fundamental flaws of the DOE plan in the following areas:

Timeliness:
Using reasonable scenarios, five years or more could be lost in pursuing demonstration of CCS from an IGCC plant, if such a facility is ever built. In the absence of mandatory CO2 reduction legislation, private sector sponsors of commercially viable IGCC plants will be unwilling to assent to project delays, risking continued cost increases in the interim. As a result, demonstration IGCC-CCS plants in the U.S. will become unaffordable, and the U.S. no longer will control its own destiny in pursuit of near-zero emissions coal-to-electricity technology development.

Commercial viability:
Commercially competitive plants utilizing IGCC technology can not and will not be built without substantial government subsidy beyond the CCS component. The Department of Energy is egregiously unrealistic in asserting that IGCC technology has reached an off-the-shelf level of maturity. It is equally unrealistic to believe DOE can launch a multi-site carbon capture initiative for DOE's estimated $1.3 billion price tag. If these plants can be built at all to provide a platform to demonstrate CCS technologies, they will be built in states whose electric consumers would be forced to assume a disproportionate share of the cost burden.

International participation
By moving swiftly back to its original vision for FutureGen, the U.S. Department of Energy can regain for the U.S. the initiative in developing effective CCS technology. International interest in the FutureGen at Mattoon project is not yet lost, and foreign participation will likely increase if DOE does not turn its back on its global responsibility and allow IGCC-CCS technology to be developed on foreign soil.

Government credibility
To regain its credibility and move FutureGen forward on a meaningful time line, the Department of Energy must acknowledge the qualifications of the two Texas and two Illinois sites by issuing its pending Record of Decision.

Conclusion
The State of Illinois urges DOE to recognize the inherent shortcomings of its post-FutureGen plan and abandon it. DOE instead should negotiate a reasonable cost-sharing agreement with the FutureGen Alliance and proceed without further delay to develop the original FutureGen project, at the highly qualified site chosen at Mattoon, Illinois.

Indiana Center for Coal Technology Research

Located in The Energy Center at Discovery Park, Purdue University

To: Keith.Miles@NETL.DOE.GOV

From: Marty Irwin, Director, Center for Coal Technology Research, and Office of Energy and Defenses Affairs, State of Indiana

Subject: "COMMENTS ON REVISED FUTUREGEN."

The State of Indiana strongly supports the DOE efforts to refocus FutureGen to invest only in the capture and store components of proposed projects. Otherwise the proposed projects should be commercially viable. We believe that this opens the door to a variety of alternatives that otherwise would remain unexplored.

Indiana is aggressively pursuing a family of clean coal options as part of its energy strategy. We have supported a series of analyses assessing the suitability of Indiana as a home for a variety of coal gasification-based industries, not just power generation. All of the options we have reviewed, in fact, produce a great deal of power. We have explored the gasification suitability of Indiana coals, our transportation and support infrastructure, and identification of the highest opportunity sequestration opportunities, among many others.

We already host one of the major successful gasification projects -- the Wabash River coal gasification facility. Through the Indiana Center for Coal Technology Research, we have provided funding for the SAIC Coal to Liquids feasibility study. Moreover, with the full support of the Governor's office, the Indiana Department of Environmental Management recently approved the permits for a 650MW IGCC power plant in Edwardsport, Indiana (explicitly designed as sequestration ready), and we are considering other gasification proposals.

With the potential of bringing multiple IGCC operations on-line, the state has entered into discussions with industry and government stakeholders about the potential for developing joint approaches to building sequestration infrastructure. Indeed, before DOE restructured FutureGen, we had agreed to collaborate with Illinois on their project.

The Governor supports and encourages each of the Indiana-based industry teams working on coal gasification projects to submit comments on the DOE RFI. Moreover, the State is committed to supporting industry responses to the RFI once issued, and will work with any projects that might be selected to participate in the FutureGen program.

Sincerely,

Marty Irwin

Marty Irwin
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Energy Center, Purdue University

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Comments of the Jamestown Board of Public Utilities on the Request for Information on the Department of Energy's Plan to Restructure FutureGen March 3, 2008

On January 30, 2008 the Department of Energy (DOE or Department) published a Request for Information on the Plan to Restructure FutureGen (RFI) The Jamestown Board of Public Utilities (Jamestown or BPU) respectfully submits the following comments pursuant to the RFI

Jamestown supports DOE's efforts to maintain and increase funding for advanced technology for coal-fired plants that mitigate carbon dioxide (CO_2) emissions to the atmosphere. Our nation has abundant and secure coal reserves that are essential to meeting our energy needs in the future. Carbon capture and sequestration or beneficial reuse (CCS) has emerged as the key technology that will allow continued use of our coal reserves to meet growing energy needs while reducing or avoiding carbon dioxide emissions to the atmosphere. CCS is still under development and will require significant governmental support to ensure it becomes commercially deployed. The BPU supports DOE's efforts to adequately fund CCS development and strongly encourages DOE to significantly increase the amount of funding sufficient to commercialize CCS in the near term

The Department should make two modifications to the solicitation to better achieve the goals of the FutureGen Program while addressing DOE's stated concerns regarding cost escalation and the need to commercialize CCS in the near term First, the solicitation should be technology neutral, allowing gasification, oxy-fuel and combustion-based systems to compete. Expanding the solicitation to include all technologies will better position the Department to benefit from technology competition in this solicitation and to address the multiple technologies and coal types that comprise our nation's electric generating fleet. Funding a range of technologies will also enable the Department to address the significant and escalating carbon emissions in developing countries where conventional coal, rather than IGCC, is the prevailing technology for new plants

Second, the Department should not place a mandatory minimum size threshold in the solicitation but instead should allow projects to establish scalability on a case-by-case basis. The current RFI proposes that DOE fund only projects at or above 300 gross MW that store a minimum of one million metric tons of CO_2 per year. Depending on the technology, projects below 300 MW and one million annual tons of carbon can be readily scaled up to large commercial plants. Importantly, projects below 300 MW offer cost control benefits in this time of substantial escalation in construction costs. For a significantly smaller taxpayer investment, these projects can demonstrate new technologies and allow DOE to invest in multiple projects under a fixed budget. The Department should not foreclose the opportunities to limit taxpayer financial exposure by excluding projects below 300 MW.

Background

The Jamestown Board of Public Utilities (BPU) is a municipally-owned utility located in western New York State. In cooperation with its project team members, including Praxair, Inc., Foster Wheeler, Dresser-Rand Group, Inc. and Battelle Labs, the BPU is proposing to construct an oxy-coal circulating fluidized bed plant (Oxy-Coal Project). The Oxy-Coal Project has the potential for carbon capture rates greater than 90% and to produce near zero emissions of criteria pollutants and mercury that would meet the emission criteria set out in the RFI for FutureGen. With the use of biomass, the oxy-coal project has the potential to be net carbon negative. The project could become operational in 2012, meeting the original schedule for the FutureGen project The CFB without the addition of oxy-coal has been issued a draft air permit by the United States Environmental Protection Agency and a Final Environmental Impact Statement (EIS) was issued in 2007. Minimal, and largely environmentally beneficial, changes would need to be made in these applications to reflect the addition of carbon capture through oxy-coal

Comments

The Restructured FutureGen Solicitation Should Be Technology Neutral

In the RFI, DOE requests comments on whether "the revised FutureGen approach should allow advanced coal technology systems, other than IGCC, that would also meet the performance requirements stated above." The BPU encourages the Department to make the solicitation technology neutral. Expanding the solicitation beyond IGCC would have important competitive and environmental benefits for the solicitation and for the nation's coal generating fleet. Encouraging a broad range of technologies would also better position the Department to address escalating global CO_2 emissions

By allowing multiple technologies to compete, the Department and federal taxpayers stand to benefit from technology competition. Technologies other than IGCC are available and can compete to reduce the cost to taxpayers while meeting the FutureGen requirements. For example, the Oxy-Coal Project proposed for Jamestown has the potential for carbon capture rates greater than 90%, and with the addition of biomass the potential to be net carbon negative, and otherwise can meet or exceed the emissions criteria set out in the RFI for FutureGen. The project is at an advanced state of permitting and could also meet the FutureGen schedule; a draft air permit and a final EIS have been issued for the base CFB project without oxy-coal and minimal changes would need to be made to reflect the addition of oxygen firing. Allowing oxy-coal and other technologies to compete in FutureGen would better position DOE to reduce costs while maximizing the benefits to taxpayers.

Expanding the range of technologies that can compete in the solicitation would also reflect the diversity in our nation's coal generating fleet. The country's generating fleet currently utilizes a broad range of fuels and technologies. Diversity has important benefits, including the ability to fully utilize multiple coal types. Moving to a monolithic IGCC generating fleet could defeat the benefits of this diversity.

Oxy-coal can separately have important benefits for carbon dioxide emissions reductions from the existing coal fleet. Projections show that over 90% of the cumulative CO_2 emissions between now and 2030 will come from the existing fleet of coal combustion power plants (74% of the CO_2 annual emissions in 2030 will come from existing coal plants). Oxy-coal can be retrofitted to existing coal power plants as well as be used in new coal plant construction. If an objective of the FutureGen RFI is to come up with an alternative strategy that would have the potential for the greatest reduction in CO_2 emissions from coal plants, oxy-coal should be a priority technology.

Expanding the solicitation to include technologies beyond IGCC will also better position the Department to address global CO_2 emissions. The RFI notes that "there have been extraordinary increases in the number of coal-fired electric power plants being constructed throughout the developing world, especially China." Recent estimates indicate that China and India are building new coal plants at a rate of two each week. The Intergovernmental Panel on Climate Change has estimated that as much as three quarters of the projected increase in energy-related carbon dioxide emitted between now and 2030 will occur in emerging economies such as China. China's coal-related emissions are projected to grow from 3.8 billion tons in 2004 to 8.8 billion tons in 2030.

Increasing carbon emissions in developing countries come largely from conventional combustion coal plants, not IGCCs. IGCC technology is complex and will present a technology challenge for many developing countries. In order to better address these emissions from developing countries, which threaten to overwhelm our national emissions, it is essential that the Department work to develop CCS technologies for conventional coal plants, and not only IGCCs. The Restructured FutureGen Program should reflect this reality by expanding the technologies that can compete beyond IGCC.[1]

The Restructured FutureGen Program Should Not Set a Minimum Size Threshold But Should Provide Flexibility to Demonstrate Scale-Up Potential

The BPU encourages the Department not to set a minimum size threshold and to provide flexibility to demonstrate scale-up potential for projects bidding into FutureGen. The RFI states that DOE will only fund projects at or above 300 gross MW that will store a minimum of one million metric tons of CO_2 per year. Projects below 300 MW and storing less than one million tons of CO_2 per year, however, are capable of demonstrating technologies which then can be scaled up to larger plants. For example, the CFB technology proposed for the Jamestown plant can support scale-up to a 600 MW plant. Jamestown requests that the Department not place a minimum size threshold in the solicitation. Instead, the Department should provide more specifics regarding its desired

[1] In the alternative, Jamestown requests that DOE clarify that oxy-coal is included within gasification under this solicitation. If DOE does not fund technologies other than IGCC through the Restructured FutureGen Program, DOE should fully fund such initiatives through the Clean Coal Power Initiative.

outcome for scale-up and require bidders on a case-by-case basis to prove how they meet those requirements.

Projects under 300 MW and with less than one million tons of CO_2 storage per year also offer critical cost control benefits that should not be ignored by the Department. As the Department noted in the RFI, there have "been significant global escalations in material and labor costs associated with the construction of new power plants." The cost escalations have led to the recent cancellation of many new generating plants and have doubled the cost of the original FutureGen Project. Plants below 300 MW are better positioned to control the total financial exposure of taxpayers related to these price escalations while continuing to provide technology benefits to the nation. The solicitation should provide the flexibility to allow these plants to compete for FutureGen funding

Providing flexibility in the size threshold is also important in light of the limited budget being proposed for the FutureGen program. As we understand the program, there is a $1.3 billion budget from FY2007-FY 2020, subject to annual appropriations. One hundred and fifty-six million dollars is budgeted for FY09 and there may be approximately $100 million budgeted for later years. Given recent and continuing price escalations, however, this may not be enough for even one project over 300 MW with capture and storage in a saline reservoir. In contrast, an integrated project below 300 MW could allow DOE to achieve the FutureGen goals within these budget constraints. The BPU encourages the Department to provide sufficient flexibility in the solicitation to bid projects that are less than 300 MW but are capable of being scaled up to larger units.

In closing, we appreciate this opportunity to comment on the RFI and applaud the Department's commitment to CCS. In order to meet the goals of FutureGen, the Jamestown BPU strongly encourages the Department to make the solicitation technology neutral and to allow plants below 300 MW to compete. With these changes, the FutureGen program can achieve its goal of a near zero emissions plant in the near term while minimizing taxpayer financial exposure.

Sincerely,

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Request for Information

The Department of Energy

Plan to Restructure FutureGen

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Location of Project: A coalition of Companies including Luminant and Jupiter Oxygen will work with the State of Texas to review the details of the two Texas sites that were selected as finalist in the Future Gen competition. The coalition will also look at other locations in Texas and determine the best site for a lignite fired [oxy-fuel] demonstration advanced clean coal project with CCS.

Narrative Description: The intent to restructure FutureGen allows for the consideration of other advanced coal technology systems. The "KEY GOALS OF REVISED FUTUREGEN" outline several specific targets that can be met with technologies not based upon IGCC. IGCC is a known technology as demonstrated by the 30 or more IGCC power plants currently in proposal stages. If the "Keys" can be considered without linkage to IGCC then other promising and arguably more practical technologies such as oxy-fuel combustion can and should be considered. Moreover, a number of technologies can be moved forward to advanced development with operational plants, so that evaluations can be made by all stakeholders of the appropriate pathways to achieve the DOE goals.

Fundamentally, Oxy-Fuel combustion is based upon the burning of a fossil fuel with oxygen instead of air, while air combustion is the basis for much of the fossil fuel based power plants in operation in the United States and the world. The current needs of the US coal-fired fleet include both new clean coal power plants and the retrofitting of existing valuable power generation assets, so that climate change issues can be addressed. IGCC does not function well with lignite and is not retrofittable to existing pulverized coal or lignite power stations. Thus coupling such an important program (FutureGen) to IGCC would dismiss our current power generation fleet, limit the availability of fuel resources (IGCC technology does not work well with all coal types), and unreasonably define future CCS projects as IGCC projects. The power industry needs a basket of technologies to choose from which includes options that can be used for new plant construction and be retrofitted to existing units. Moreover, the DOE does not need to be in the business of picking a technology winner, but rather should be moving all clean coal technologies forward.

The proposed project is for a 25-50 MW new design oxygen combustion power plant using lignite coal, with undiluted high flame temperature heat transfer for greater radiant heat transfer, and at least 90% CO2 sequestration as shown by prior testing of Jupiter's particular oxy-fuel technology and the DOE's own Integrated Pollutant Removal (IPR) system. NOx will be kept at ultra-low levels at combustion.

Prior testing indicates that when Jupiter Oxygen's Oxy-fuel technology is coupled with the DOE's own Integrated Pollutant Removal (IPR) system, 99% capture of particulate, 99% capture of Sox and 90% mercury removal is both practical and cost effective. Emissions of NOx, S0x and mercury will not exceed the original FutureGen levels stated in the RFI.

This project will demonstrate the integrated operation of a coal fired power plant on the grid with C02 capture. It will help establish standardized technologies and protocols for capture and sequestration, including monitoring, mitigation and verification, while showing a practical CCS approach that has sufficient reliability and operability for commercial needs.

The target geological formation storage potential will be accurately quantified, and steps taken to detect and monitor any surface leakage, equipped for mitigation strategies which will be implemented in the unlikely event of a leak. Information necessary to estimate costs for future CO_2 management will be developed using this oxy-combustion approach with CCS. It will show a practical reality for such operations.

Technical and economic data will be gained that is needed for both new plantsand for retrofitted facilities to gain acceptance by the coal, electricity, and banking industries, the environmental and international communities, and the public, as a cost-effective means for producing electrical power in a carbon constrained world. Net operating profits will be used to reimburse the DOE for its costs.

Status of the Project: Testing to date with Jupiter Oxygen's combustion technology using oxy-fuel combustion has advanced to the point where new build design work is feasible, as is the building of such a plant. This testing indicates fuel savings with a corresponding avoidance of CO2, lower oxygen costs with an on-site oxygen plant and heat recovery, and the ability to create a fully equipped carbon capture ready plant by combining Jupiter Oxygen's technology with commercially available capture equipment that also will provide for heat recovery. The testing also indicates that the DOE COE and capture goals can be met.

Moreover, modeling work for such a new build plant has been done with the National Energy Technology Laboratory.

Furthermore, full scale demonstrations of CCS may limit the quality and quantity of research needed to develop several commercial options. By defining the bar for a restructured FutureGen at 300 gross MW per unit train, the program drives the capital cost of the demonstration project higher, thus reducing funds for developing different types of clean coal technologies. If instead of one or two 300 MW commercial units based upon IGCC technology, several 25 to 50 MWe demonstration projects could provide the DOE with:

- Multiple technologies options for the power utility industry to consider;
- Geographic diversity of project locations (factors such as sequestration and transportation);
- Several fuels tested for capture and;
- Experience based upon implementation of the projects so as to share the experience among the project participants, regulators, local officials and future wide scale applications.

This proposed project can meet all of the substantive goals in the RFI, but do so using undiluted high temperature oxygen combustion heat transfer, creating the development step necessary for commercialization meeting the nation's energy security, climate change, and COE needs for both new plants and retrofitted facilities.

Timeline: The coalition can meet the timeline objectives of 2015 if the funding timeline stays at what was outlined in the RFI. From a design engineering, construction and procurement standpoint, this is not an issue due to the state of the technology and the commercial availability of the components. However several administrative, regulatory and site specific issues need to be addressed.

- The requirements to fulfill NEPA need to be expedited in order to fast track the project and keep it within the projected budget;

- The State of Texas and its Commission on Environmental Quality will need to move quickly to develop requirements for and permit a new advanced clean coal power plant;

- The numerous regulatory issues involved with the transportation and sequestration of CO_2 and some mechanism for the indemnification of the coalition need to be developed.

The coalition will work with the DOE and the State of Texas to solve CO_2 capture and storage liability issues and to fast track the State's permitting requirements for an advanced clean coal power plant.

Cost and DOE Contribution: The Texas Coalition is interested in working with the DOE under the revised FutureGen approach on a smaller Advanced Clean Coal project in the range of 50 MWe. The project would include Jupiter Oxygen's oxy-fuel technology and the DOE's IPR system. The IPR would serve as the projects CCS per the Keys outlined in the RFI. The cost for the plant would be $135,000,000 not including the cost for CO_2 transportation, sequestration and monitoring. The cost breakdown is as follows:

50MWe Power Plant Project

- Cost $135,000,000;

- Coalition share of cost $118,800,000;

- DOE cost for CCS (IPR) $16,200,000 plus transportation, sequestration and monitoring equipment.

The cost of building larger power plants using Jupiter's Oxy-fuel technology and the DOE's IPR system as the CCS not including transportation, sequestration and monitoring is:

150 MWe Power Plant Project

- Cost $300,000,000;
- Coalition share of cost $264,000,000 plus transportation, sequestration and monitoring equipment;
- DOE cost for CCS (IPR) $36,000,000 plus transportation, sequestration and monitoring equipment.

300MWe Power Plant Project

- Cost $600,000,000;
- Coalition share of cost $528,000,000 plus transportation, sequestration and monitoring equipment
- DOE cost for CCS (IPR) $72,000,000 plus transportation, sequestration and monitoring equipment.

We strongly encourage the DOE to do plants smaller then the 300 MWe outlined in the RFI. By doing smaller demonstration projects the DOE would be able to help move more technologies with CCS forward to commercialization, which would be a major benefit to the electric power industry and to the nation. It would also position the United States as the world leader in the development of cost effective technology for producing electricity in a carbon-constrained world

With over 600 existing coal fired power plants in the United States, the DOE needs to be moving aggressively to find technology that can be used to retrofit these existing plants. They represent a major investment to the electric power industry and are an important part of America's power grid. IGCC technology does not address the existing fleet nor can it be used on all of the coal available in the United States. We recommend that under the restructured futureGen approach that the DOE move forward with a retrofit project. The cost to retrofit a small coal fired power plant using Jupiter's Oxy-fuel technology and the DOE's IPR system as the CCS not including transportation, sequestration and monitoring is:

50 MWe Retrofit Project

- Cost $70,000,000;
- Coalition share of cost $61,600,000;
- DOE cost for CCS (IPR) $ 8,400,000 plus transportation, sequestration and monitoring equipment.

20 MWe Retrofit Project

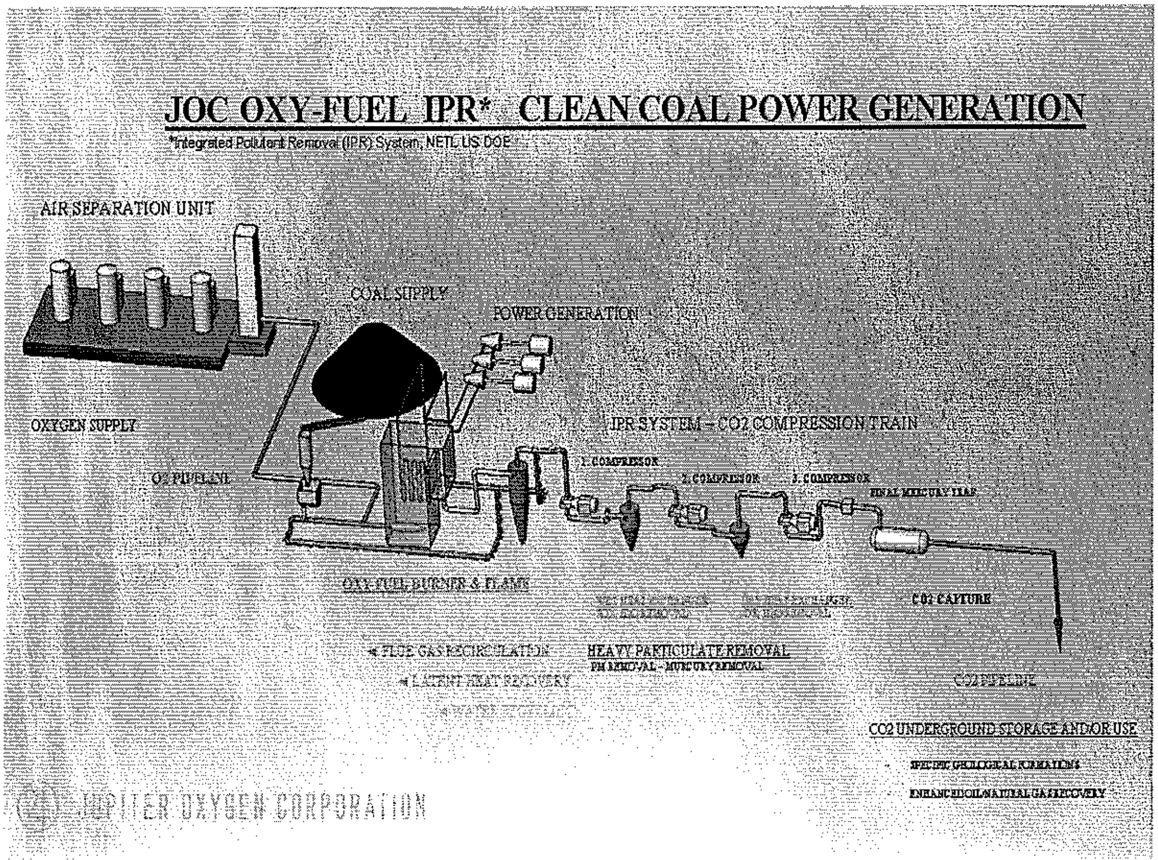
- Cost $42,000,000;
- Coalition share of cost $36,960,000;
- DOE cost for CCS (IPR) $5,040,000 plus transportation, sequestration and monitoring equipment.

Issues or Barriers: The continued concern about the liability of CO_2 sequestration continues to be a problem for the companies involved. The coalition will work with the DOE and the State of Texas to help solve that issue. However the Federal and State governments are the only institutions that can safely take on this liability And until a solution for this problem is found, it will continue being a barrier to CO_2 sequestration.

Since there is no established industrial or commercially accepted criteria for transportation and CO_2 sequestration, modification to the specific equipment installed will have to be made due to the developing specifications of sequestration. This would increase cost and unfairly penalizes the companies receiving the grant. It also could potentially put the DOE timeline at risk.

Other Information and Concerns: Jupiter Oxygen's patented process utilizes up to 100 percent pure oxygen to burn any type of coal including lignite to produce steam for power generation with enhanced fuel efficiency. The combustion of fossil fuel with oxygen rather then air, using an undiluted high flame temperature for greater radiant heat transfer, is the basis for much of Jupiter's work. Working with NETL, Jupiter also has practical experience in the capture of CO_2 and the removal of all pollutants from a coal fired oxy-fuel combustion process The other members of coalition, such as Luminant, have a vast amount of experience building and operating lignite fired power plants.

The combination of Jupiter's Oxy-fuel technology combined with the DOE's IPR system creates a hybrid process that is the pathway toward near zero emissions (net 95% with start-up and shutdown) from a coal fired plant, including the capture of more than 99 percent of the CO_2 (net 95% with start-up and shutdown). The all pollutant approach enhances the overall efficiency and effectiveness of the process. Tests have shown greater than 99 percent sulfur removal, 99 percent + removal of PM matter including PM 2.5. Testing also indicates NOx below 0.05 lbs./ mmbtu and greater than 90 percent mercury capture is feasible with the combined Oxy-fuel IPR hybrid technologies.



JOC OXY-FUEL IPR* CLEAN COAL POWER GENERATION
*Integrated Pollutant Removal (IPR) System, NETL US DOE
AIR SEPARATION UNIT
COAL SUPPLY
POWER GENERATION
OXYGEN SUPPLY
O2 PIPELINE
IPR SYSTEM – CO2 COMPRESSION TRAIN
1. COMPRESSOR
2. COMPRESSOR
3. COMPRESSOR
FINAL MERCURY TRAP
OXY-FUEL BURNER & FLAME
CO2 CAPTURE
FLUE GAS RECIRCULATION
HEAVY PARTICULATE REMOVAL
PM REMOVAL - MERCURY REMOVAL
LATENT HEAT RECOVERY
CO2 PIPELINE
CO2 UNDERGROUND STORAGE AND/OR USE
SPECIFIC GEOLOGICAL FORMATIONS
ENHANCED OIL/NATURAL GAS RECOVERY
JUPITER OXYGEN CORPORATION

Comments of:
Leucadia National Corporation
Department of Energy Restructured FutureGen Approach
March 3, 2008

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Leucadia National Corporation ("Leucadia") appreciates the opportunity to provide comments on the Department of Energy's (DOE) restructured FutureGen approach. Leucadia supports DOE's revised approach and agrees that it will better serve the future energy needs of the nation, the power sector and taxpayers.

Leucadia would like to participate in the restructured FutureGen program by developing a commercial-scale saline aquifer (and potentially New Albany Shale) sequestration demonstration at its Indiana coal to substitute natural gas (SNG) facility. The facility, which is under development, will sell SNG under contract to regulated gas and electric utility companies, including a regulated electric company that will use the SNG to produce [redacted] of power in combined cycle plants Preliminary geologic evaluations by the Indiana Geologic Survey indicate the potential of over 700 million metric tons of CO_2 storage around the site in saline aquifer and shale formations.

DOE's restructured approach provides the best opportunity to maximize the advancement of commercial-scale carbon capture and sequestration technologies with limited federal resources. By expanding the program to include consideration of coal gasification projects that produce SNG for electricity generation ("SNG for power"), the benefits of the restructured program will be enhanced even further

Coal gasification to produce SNG for electricity production is an alternative advanced coal technology paradigm that offers significant energy and environmental benefits for the nation and can help DOE achieve FutureGen objectives at low cost. Fundamental benefits of SNG for power include:

1 Advanced coal gasification technology can produce SNG to supplement natural gas supplies for the 400 giga-watts (GW) of existing natural gas generating capacity and the 100 +GW natural gas capacity additions likely over the next 30 years. Electric sector

demand for natural gas is projected to far outstrip demand growth in other sectors and SNG provides one of the few alternatives for supplying that demand growth with a secure, domestic resource—e.g. coal-derived SNG.

2 The cost of capturing carbon in SNG facilities is embedded in the SNG production process and price Therefore, no additional cost is associated with capturing CO_2 at SNG facilities so all incremental resources for CCS at SNG facilities can be used for sequestration activities. Including SNG projects in the restructured FutureGen program will increase the number and diversity of projects DOE can support and accelerate progress on addressing sequestration technical challenges in diverse geologic formations.

3 SNG for power is an alternative prototype for producing electricity from domestic coal with advanced technology and CCS that has the potential for significantly improving energy security and environmental progress. [redacted]—establishing the technical feasibility of sequestration is critical to enabling widespread deployment of SNG for power with CCS in a manner that could have a substantial impact on U.S energy and electricity supply.

For these and other reasons discussed below, DOE should support CCS activities at SNG for power projects (in addition to IGCC) in the restructured FutureGen program

The comments below describe:

1) Leucadia and its gasification development activities;

2) [redacted]

3) Why projects that convert coal to SNG for use in natural gas power plants should be included in the restructured program; and

4) Legal and regulatory matters DOE should consider in the restructured program.

Leucadia National Corporation

Leucadia is a NYSE listed (LUK) diversified holding company with a broad portfolio of investments. As of September 30, 2007, the company's total consolidated assets were [redacted]

Leucadia is focused on "value investments." It has holdings in energy, mining, timber, communications, banking, insurance, manufacturing, health care, real estate and wineries. The chairman and president of the closely-held company have served the company since 1978, [redacted] With its strong balance sheet and past financial success, Leucadia has been recognized by financial markets as an attractive project sponsor, including by the State of Louisiana Bond Commission, which awarded Leucadia $1 billion of GO Zone bonds for its Lake Charles, LA SNG project

Leucadia Gasification Development Activities

Leucadia developed an interest in gasification about five years ago, and has pursued development of several projects since. [redacted] Leucadia has assembled a group of experienced industry professionals with varied technical and financial backgrounds to work for the company in developing its projects.

Leucadia is pursuing a business model for SNG [redacted] This structure creates very high credit to support use of low-cost debt instruments, including those available through federal programs such as federal loan guarantees under EPAct 2005 and tax exempt bond financing under Katrina and Rita redevelopment programs. This structure also provides the opportunity for achieving a stable long-term equity return with reasonable risk/reward that justifies expenditures of high risk equity capital for project development.

Leucadia's interest in gasification generally and SNG specifically is based on a fundamental belief that technologies to utilize domestic coal and petroleum coke resources that address climate change and other environmental challenges are vital to the nation's energy security and global environmental progress SNG is one of the few alternatives the nation has to expand domestic gas production and reduce growing dependence on imported liquefied natural gas (LNG). In addition, production of SNG from domestic coal is an economic technology today, with production costs below current natural gas market prices. Over time the nation's natural gas supply is at risk of following in the footsteps of oil, causing the U S to become increasingly dependent on supplies from unstable regions and potentially subject to cartel pricing Domestically produced SNG can help mitigate this future scenario in natural gas markets and do so with an advanced coal technology platform that can help accelerate commercialization of carbon sequestration technology

Each of the SNG projects Leucadia is developing includes significant [redacted] For this reason, the SNG projects can be thought of as "IGCC by pipe." As discussed below, SNG projects that supply SNG for electricity production can provide excellent platforms for FutureGen supported CCS activities at low cost

[redacted] In the Illinois Basin, no CO_2 EOR operations are currently active and the potential for CO_2 use for EOR is more limited. Furthermore, demonstrating commercial-scale sequestration in saline and other formations in the Illinois Basin will be very important for the considerable number of coal plants operating in the region and for future use of the substantial coal reserves in the region Leucadia would like to work with DOE to help establish the feasibility of commercial-scale CO_2 sequestration in Indiana

Indiana SNG Project

The Indiana SNG Project [redacted]

The Project will provide considerable savings to Indiana consumers, reduce natural gas price volatility, support national energy security, and advance environmental policy objectives.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] Approval of the SNG purchase contracts by the IURC will ensure that the contracts are in place [redacted]. This assurance is provided by legislation that was initially passed by the Indiana Legislature May, 2007 (H.B. 1722) and updated with clarifying amendments in March 2008 (S.B. 223). The legislation makes clear that if the IURC approves the utility SNG purchase contracts, [redacted]

The Project applied for a Federal Loan Guarantee in the initial solicitation for pre-applications issued by DOE in December 2006, but was not selected to submit a full application. Indiana Gasification understands that the Project was not selected [redacted]

[redacted] As discussed below, the cost of capturing this CO_2 is already embedded in the SNG production process and price, so **no additional costs will be associated with capturing CO_2 for sequestration**. Sequestration activities will, however, require additional capital and operating costs associated with compressing, transporting and injecting CO_2 (as well testing, measurement, monitoring, and verification activities) These sequestration costs will mirror the costs of other geologic sequestration projects, with the final cost likely dependent on the location and specific geologic characteristics of the target formations.

The Indiana Geologic Survey has conducted a preliminary feasibility assessment of geologic sequestration options within a 25 square mile region [redacted] The Geologic Survey estimated that over 700 million metric tons of CO_2 could potentially be stored in saline aquifer and shale formations in the area. [redacted]

Because there will not be any costs to a CCS demonstration associated with capturing CO_2 from the Project, Indiana Gasification believes sequestration activities at the site (including compression, transport, injection, monitoring and testing) could be carried out for a cost of [redacted] These provisions should enable the Project to continue to sequester CO_2 after conclusion of the FutureGen demonstration, increasing the value of a demonstration initiative at the site.

[redacted] Commercial operations would begin in 2012 and the Project would be in a position to begin providing CO_2 for sequestration activities at that time, a schedule consistent with the DOE timeframe.

SNG for Power should be Included in Restructured FutureGen Approach

DOE's request for public comments specifically solicits input on whether advanced coal technology systems, other than IGCC, would meet DOE's performance requirements. Coal technologies that produce SNG for power production meet DOE's requirements, will advance DOE's objectives, and should be included in the program. Inclusion of SNG for power in the program will support the following enunciated DOE objectives at low cost:

- Demonstrate in the United States commercial integrated operation of a gasification-based coal conversion system with CO_2 capture and storage;
- Verify the effectiveness, safety, and permanence of carbon sequestration;
- Demonstrate approximately 90 percent CO_2 capture and storage on one nominal 300 MW train (albeit by pipeline) with annual requirements of one million metric tons in a saline aquifer, and
    - 99% sulfur removal
    - 0.05 lb/mmBtu NOx emissions
    - 0.005 lb/mmBtu particulate matter emissions
    - 90 percent mercury removal
- Help establish standardized technologies and protocols for deployment of CCS, including CO_2 monitoring, mitigation and verification;
- Accurately quantify storage potential of the target geologic formation;
- Detect and monitor surface leakage, if any, and in the unlikely event of leakage, demonstrate the effectiveness of mitigation strategies;
- Develop information necessary to estimate costs of future CO2 management approaches;
- Demonstrate practical realities of SNG with CCS as a coal-based electric power alternative;
- Produce the technical and economic data needed for these types of plants to gain acceptance by the coal, electricity, and banking industries; the environmental and international communities; and the public as cost-effective means of producing electric power in a carbon-constrained world.

In the case of SNG for power, carbon capture and sequestration activities [redacted] would be decoupled from the majority of the power generation that would occur at combined cycle or other natural gas power plants owned by separate entities In SNG for power, there is no physical integration of the power block and gasification system other than a natural gas pipeline [redacted] There are many advantages to SNG for power that make it an important energy technology for the U.S and ideally suited for accelerating commercial deployment of carbon sequestration. Some of the benefits of SNG for power include:

> <u>Carbon Capture and Sequestration Economics</u>—The cost of carbon capture is embedded in the cost of producing SNG. Therefore, SNG technology can help advance commercial-scale sequestration at much lower cost than technologies that incur significant additional costs for capture. Including SNG projects, in addition to IGCC, will enable DOE's resources to go further and enhance achievement of DOE objectives by enabling DOE to providing funding assistance to a greater number of more diverse projects located in more geographic regions.
>
> <u>SNG Plants can be Located near Sequestration and Coal</u>—As a strategy compared to IGCC, SNG for power has the advantage of separating the gasification plant from the power plant. By decoupling the two, the gasification facility can be located near geologic formations most amenable to CO_2 sequestration and near economic coal supplies while the power generation facilities can be located near load centers. Power can be generated at more than one facility and can be generated near the markets where it is needed, helping to reduce transmission system congestion
>
> <u>SNG can be Transported in Existing Interstate Pipelines</u>—SNG can be moved in existing natural gas pipelines and can help free up capacity Adding SNG to pipeline systems can help improve pipeline capacity by adding supply closer to where it is used and away from traditional supply points [redacted] Another advantage of adding SNG to existing pipelines is that its heating value is at the low end of most pipeline specifications (~970 mmbtu/Mcf), which can help balance the much higher heating value gas increasingly being delivered from LNG re-gas facilities.
>
> <u>Use of Existing Underutilized Fleet of Natural Gas Power Plants</u>—Over 400,000 MW of natural gas generating capacity exists in the U.S—almost as much as coal and nuclear capacity combined. Most of these plants, particularly in the Midwest, operate at very low capacity factors (typically in the 25% range). Rather than building new generating plants, these existing plants can be used economically with SNG (or a mix of SNG and natural

gas). [redacted] Use of this existing capital stock is economically efficient and prudent. Furthermore, demand for natural gas in the electric power sector is projected to grow in coming decades as excess capacity is used and new natural gas power plants are built. SNG offers a gas supply alternative from domestic coal that can help reduce dependence on overseas LNG imports for needed supply

Less Integration can Reduce Cost and Improve Reliability—SNG for power is a simpler technology than IGCC because there is no thermal integration between the combined cycle power system and gasification block. The lack of integration reduces efficiency, but improves reliability and reduces capital and operating costs. Furthermore, with SNG to power, the combined cycle generating plants can buy replacement gas when SNG is not available and, conversely, SNG can be sold into gas markets when the power plants are not available or don't need the SNG. This flexibility largely alleviates reliability concerns that may inhibit early commercial development of other advanced coal technologies.

Operating Flexibility and Load Shaping—SNG for power systems can be operated as base, intermediate or peaking load because the combined cycle plants (or combustion turbines) can dispatch independent of the gasification facility. [redacted] These essential flexibilities offered by SNG to power systems can help fulfill market demands and enhance the overall economics and benefits of this advanced coal power system.

Coal gasification to produce SNG for electricity production is an alternative advanced coal technology paradigm. SNG for power has significant energy and environmental benefits for the nation and can help DOE achieve FutureGen objectives at low cost. DOE should support CCS activities at SNG for power projects (in addition to IGCC) in the restructured FutureGen program.

Legal and Regulatory Matters DOE should Consider

In implementing its restructured FutureGen approach there are two important regulatory and legal issues that should be considered by DOE. A first issue is permitting of CO_2 sequestration activities. Projects selected to participate in the restructured FutureGen program should be used to help design appropriate permitting requirements, including measurement, monitoring and verification protocols for CCS. For this reason, DOE should consider how FutureGen projects will receive early permitting treatment and be used to help establish a formal CCS permitting and regulatory regime

A second issue is liability. Although environmental and health hazards from CO_2 sequestration should be extremely remote, they are not zero. There is also the possibility that some sequestered CO_2 could leak over long periods, which could undermine credits claimed for the sequestration. For initial projects that sequester large quantities of CO_2, these liability issues need to be addressed. States and the federal government must both play a role in helping address these issues to ensure they do not undermine progress demonstrating CCS in the near term.

Conclusions

Leucadia appreciates the opportunity to provide these comments and looks forward to working with DOE on its restructured FutureGen approach. Establishing the commercial readiness of CCS activities is vital to the continued use of domestic coal resources in the context of carbon abatement. Advanced coal technologies that produce SNG for use in electricity generation can and should play a role in helping reduce the cost of demonstrating large-scale CO_2 sequestration DOE's support of SNG for power along with IGCC will help lower the cost of demonstrating commercial sequestration, which in our view is the fundamental technical challenge in CCS.

[redacted] By supporting CCS at prototype SNG projects, such as the Indiana SNG Project, DOE can help establish use of coal for SNG production as an important technology option for using domestic coal, increasing domestic gas supply and addressing climate change.

Expression of Interest on the DOE FutureGen Program
by LSG Holdings, Inc.

1. **Name:** LSG Holdings, Inc. (Florida registered company)
   Point of Contact: Robinson ("Rob") Gourley, President
   Telephone Number: 941-923-8972
   Mailing Address: 6233 Old Ranch Road, Sarasota, FL 34241
   E-mail Address: Robgourley@prodigy.net

2. **Location of Project:** Sarasota, FL

3. **Narrative description of project that includes the status of project development and the technical and financial qualifications of the project team to conduct the project.**

   Carbon **is** a renewable energy source. LSG Holdings, Inc. ("Company" herein) has developed a stable hydro gas that unlocks the intrinsic energy from carbon through redundant processes similar to when ceramics are used. We can demonstrate that the amount of energy generated from carbon can increase 5 to 10 fold, with a more efficient burn that reduces emissions. Additionally, we have developed a polarized water resulting from the infusion of the hydro gas, that will clean carbon collected on scrubbers. The residual carbon can be made into pellets and subsequently used back in the energy stream, again reducing emissions.

   Our project team is currently undergoing research on energy efficiencies on the hydro gas applications for the Canadian tar sands operations. The project team includes the following:

   Rob Gourley, President – Mr. Gourley is a mechanical engineer who has over 20 years of experience in power systems for Alaska Petroleum Contractors and Mukluk Freight Lines in Prudhoe Bay, Alaska (the Alaskan Pipeline).

   Ted Suratt, Vice President and Chief Scientist -- Mr. Suratt has training in nuclear physics and he developed more than 250 different formulas for industrial customers including decontamination cleaners for Dupont's Nuclear Plant.

   John Kidd, Energy and Financial Consultant – Mr. Kidd has a background in multiple industrial sectors and currently involved in an oil and gas exploration company in Alaska

   Dana Gourley, Secretary – Ms. Gourley is a biologist who worked under a contract between United Technologies Corporation and the U.S. EPA on establishing nationwide water pollution standards for multiple industries including the battery manufacturing sector.

The founders of the Company currently fund the research on the hydro gas and its wide applications. We have not opened the Company to outside investors although the inquiries and investment interest continue to increase.

4. **Discussion of the company's ability to meet or exceed the time frame set forth in the above schedule.**

   We do not anticipate any difficulties for meeting the time frame as described.

5. **Estimate amount of DOE contribution (in percentage and/or dollars) that would be required for the company to pursue the project with IGCC-CCS technology.**

   Our best estimate is $10 million including $5 million research and development and another $5 million for the manufacture of a scaled unit.

6. **Any technological, financial, or legal issues or barriers that DOE should be made aware of that limit the effectiveness or feasibility of DOE's restructured approach to FutureGen.**

   None we are aware of at this time. We will request a confidentiality disclosure agreement prior to demonstrating the technology.

7. **Other information or concerns that would assist DOE in implementing the revised FutureGen.**

   None we are aware of at this time. We are of the opinion that our technology is compatible with the FutureGen objectives for the restructured approach.

Luminant

Luminant Generation Company LLC

1601 Bryan Street
Dallas, TX 75201

Comments in Response to Department of Energy's Request for Information (RFI) on a Plan to Restructure FutureGen

Luminant Generation Company LLC (Luminant) appreciates the opportunity to provide these comments and an expression of interest in response to the RFI on the revised approach to FutureGen. Luminant, a subsidiary of Energy Future Holdings Corp. (EFH), is a competitive power generation business, including mining, wholesale marketing and trading, construction and development operations, with more than 18,300 megawatts (MW) of generation in Texas, including 2,300 MW of nuclear and 5,800 MW of coal-fueled generation capacity. Luminant is a member of the FutureGen Industrial Alliance and strongly supported the initial FutureGen approach. Likewise, Luminant supports the restructured approach, and we are providing several comments to help make this process successful. Also, as described later in this document, Luminant has already requested proposals from qualified firms offering coal gasification technologies with the ability to capture carbon dioxide emissions and has received expressions of interest from 14 companies

Comments

The U. S. Department of Energy (DOE) RFI states that DOE "will contribute not more than the incremental cost associated with CCS technology for a single power train." Luminant believes that "incremental" means that DOE should fund not only the capital cost of the carbon capture and storage (CCS) equipment, but also provide for the ongoing parasitic load (30% to 40% estimate) to the plant that results from CCS, and the cost of maintaining the transport and sequestration infrastructure. It is imperative that coal remain a viable energy resource, and, at least in Texas, these IGCC projects will be competing with natural gas-fired combined cycle gas turbine (CCGT) projects that do not have this impact to their auxiliary load. Since April 2007, air quality permit applications for almost 10,000 megawatts of CCGT have been submitted to the Texas Commission on Environmental Quality. In 2006, natural gas generation made up 72% of the capacity and 49% of the generation in Texas.

Many advanced coal technology system projects are in the early stages like Luminant's, and we encourage DOE to provide for future opportunities to request funding under the restructured FutureGen approach.

Funding for a commercial carbon dioxide (CO_2) CCS facility on one nominal 300 MW train could lead to efficiency and capture operational issues given that there is no commercial facility of that scale in operation. For example, in the mid to late 1970s, utilities began to install full-scale, commercial flue gas desulfurization systems and spent the better part of the next fifteen years learning how to operate them at the proper pH, with an oxidized or reduced atmosphere and without scaling or plugging towers. This fairly simple chemical process must be operated very carefully, or reliability and efficiency are reduced. Luminant submits that the learning curve from an operational perspective will be similarly high for a new process to remove CO_2 from an exhaust stream. To help solve this challenge, the ability to fund a CO_2 CCS facility in three stages - such as testing, pilot and commercial scales - could benefit the energy industry and consumers far more than starting from a commercial facility that immediately could face significant technical challenges.

Since over 300,000 megawatts of coal-fired generation is currently operating, Luminant recommends that the DOE provide funding for advanced coal technology systems, particularly post combustion capture, either in this program or another, or both. For example, Luminant currently provides a host power plant site for Skyonic to perform a pilot-scale demonstration of their SkyMine™ process, and Luminant is aware that Skyonic is also submitting comments for this RFI.

While Luminant supports the restructured FutureGen approach, from an operational success perspective we also feel that the CO_2 CCS target of 90% is too high since no technology to date has demonstrated this level commercially. Luminant recommends starting with a 50% target that could later be adjusted upward. The resulting emission rate would roughly equate to the emission rates of a gas-fired facility. For our abundant coal resource to compete with a limited supply of natural gas, the cost of technologies must remain competitive.

Luminant also believes that carbon transport and storage of CO_2 can not only be reasonably decoupled from the power generation aspects of the project and performed by separate entities, but that in many cases it will need to be decoupled. Power generators, predominantly, are not in the pipeline or deep geological injection businesses and would want to turn over the transportation and sequestration efforts to those that have that expertise.

Expression of Interest

The information requested in the RFI is provided below.

Name – Luminant Generation Company LLC
Point of Contact – David P. Duncan
Telephone Number – 214-875- 8647
Mailing Address – 500 North Akard Street, Dallas, TX 75201
E-Mail Address – David.Duncan@luminant.com

The location of the project(s) is yet to be determined. The following narrative description of the project(s) explains the selection process.

Luminant expects to select integrated gasification combined cycle (IGCC) and/or other gasification technologies with carbon dioxide (CO_2) capture that can be commercially deployed using lignite or subbituminous coals as their primary fuel sources. These projects would be located in Texas which has passed legislation to streamline the permitting process and provides grants and tax incentives for clean energy projects. Texas also has experience in utilizing CO_2 for enhanced oil recovery Luminant will use a multiphase approach to develop and construct these projects including (1) project definition; (2) project development; and (3) project engineering, procurement and construction. A request for proposals (RFP) for Phase 1 (project definition) was issued on December 4, 2007 Luminant has received expressions of interest and intents to bid from 14 firms. The engineering firm Sargent & Lundy has been selected to provide owner's engineer services. Tasks for Phase 1 include determining configuration options, and recommendations for design basis and general specifications; assisting Luminant in site selection; evaluation of commodity byproducts and their commercial viability; determining alternatives for environmental control technologies, establishing a plan to improve fixed and variable operating costs and plant performance; and assisting in developing an initial pro-forma operating budget Luminant's timeline calls for detailed proposals to be submitted by June 2008

The project team is composed of both internal and external resources with extensive experience in the technical aspects of gasification and power generation in the United States and overseas The internal resources have led the operation and development of conventional coal power plants. In addition, the team has extensive background in chemical and other engineering disciplines that will be valuable in the evaluation of feasible technologies for gasification.

Our external resources include Sargent & Lundy which is a renowned engineering firm with extensive experience in evaluating and supporting gasification and integrated gasification combined cycle technologies in the United States and abroad. Also, firms wishing to submit a proposal for Luminant's project(s) must have a coal gasification technology that has been successfully demonstrated at the commercial or pilot scale level. Luminant expects to select IGCC technologies that best fit the utilization of lignite and/or PRB as a fuel source. Selection of technology vendors is expected to be completed by the fourth quarter of 2008. Given that the process is in early stages, Luminant will not know the final funding requirements until after the supplier of technology has been selected

The Texas Legislature has been proactive in passing legislation that provides for tax credits, indemnification, transfer of liability and other considerations for the original FutureGen approach. As a result, Luminant believes that the Legislature would continue to be supportive of advanced clean coal technology development under the restructured FutureGen approach.

Thank you again for considering Luminant's comments We look forward to working with you.

Sincerely,

Mike McCall
Chief Operating Officer

Request for Information (RFI) Response to U.S. Department of Energy's Plan to Restructure FutureGen

I. Contact Information

Mike Sawruk
President
M&M Energy, LLC
msawruk@sawruk.com
Phone: 407 647 1060
Fax: 407 841 0404

II. Project Location

The Great Lakes Energy Research Park IGCC-CCS ("Project") is located in Pine River Township, adjacent to the City of Alma, Gratiot County, Michigan, approximately 50 miles north of Lansing, Michigan. The Project is situated on a 323-acre site that is part of a larger 1400 Acre Commercial Research Park and has been obtained from the City of Alma and various private property owners.

III. Project Description

Great Lakes IGCC, LLC (Great Lakes IGCC) has planned an IGCC-CCS facility configured to operate as a base load electrical facility, which will demonstrate significant performance, efficiency, and emission improvements that will make it the cleanest coal fueled power plant in the world.

The plant will be designed for the capture and sequestration of CO2 for the purpose of Enhanced Oil Recovery. The Great Lakes Energy Research Park ("Project") will be the first Integrated Gasification Combined-Cycle (IGCC) facility to co-produce (1) over 728 MW electric power and (2) permanently sequester over 3.8 million tons per year of carbon dioxide through coupling with Carbon Capture and Storage (CCS) technology, which will ultimately recover over 180 million barrels of stranded oil.

Great Lakes IGCC has secured a site on which it plans to construct a polygeneration project consisting of a power block utilizing an IGCC module, a carbon capture and carbon sequestration module, a state-of-the-art refinery, and other process thermal industrial users. The IGCC facility, which is a stand-alone project that will be constructed regardless of plans for the refinery, represents the first part of this multiphased project and will have a nameplate capacity of 605 MW.

The IGCC plant will utilize Conoco-Phillip's E-Gas gasification process and Siemens SGT6-5000F gas turbines and combined cycle technology. The E-Gas gasification process provides the most environmentally clean and efficient method for effective consumption and utilization of the Nation's abundant coal resources.

Bituminous coal will comprise substantially all of the fuel input for the Project, which will have a total nameplate generating capacity of approximately 728 MW gross, 605 MW net after internal loads for the IGCC process. The high thermal efficiency and resulting high fuel efficiency of combined-cycle plants are well known, based on extensive experience with natural gas-fired combined-cycle plants.

The Project will benefit from two primary revenue streams: the sale of power and the sale of CO_2. It is anticipated that nearly all of the net power (532 MW) will be utilized by members of the Michigan Public Power Agency ("MPPA") and other utility entities. A portion of the 532 MW of capacity will be reserved by the Great Lakes IGCC for energy utilization by the refinery when that phase of the Project is complete. Approximately 73 MW of capacity will be utilized for the compression and sequestration of CO_2.

The captured CO_2 by-product will be sold to SemCrude, L.P ("SemCrude") under long term agreements. SemCrude will provide for pipeline transportation of the CO_2 to depleted oil wells for injection into those wells as part of the EOR process. The EOR process by CO_2 injection will permanently sequester the CO_2 and provides the potential for recovery of at least 180 million barrels of stranded oil from nearby reservoirs. Thus, not only will the Project displace a portion of imported fuels with domestic coal, its beneficial impact on America's energy independence will be multiplied through the development of domestic oil reserves that, until now, have been stranded. Replacing part of imported hydrocarbon products with domestic coal helps minimize the adverse impacts on the U.S. fuel supply caused by instability in the political conditions of other countries and uncertain foreign economic conditions, thereby also contributing to important national defense goals as well

The Project will also produce unique and unparalleled environmental benefits. In addition to the landmark environmental benefit of permanent carbon capture and sequestration, the Project will also result in the re-completion of existing oil wells in the immediate area of the Michigan Basin, long sought by local environmentalists.

Synergies between the various processes of the project will be exploited to maximize by-product utilization, decrease costs and increase efficiencies. The chief synergy and prime example of byproduct utilization is, of course, the capture and sale of CO_2. However, numerous other synergies exist, due in part to the unique nature of the Energy Park being developed by the Project, which also will include a new refinery. Examples of these synergies include:

- Steam discharged from the power steam turbine will serve as an energy supply for the crude oil refinery, which also will have the ability to purchase low cost electricity produced by the power block with minimal transmission infrastructure.
- The refinery will receive crude oil recovered by the CO_2-EOR process from depleted wells in the Michigan Basin region.

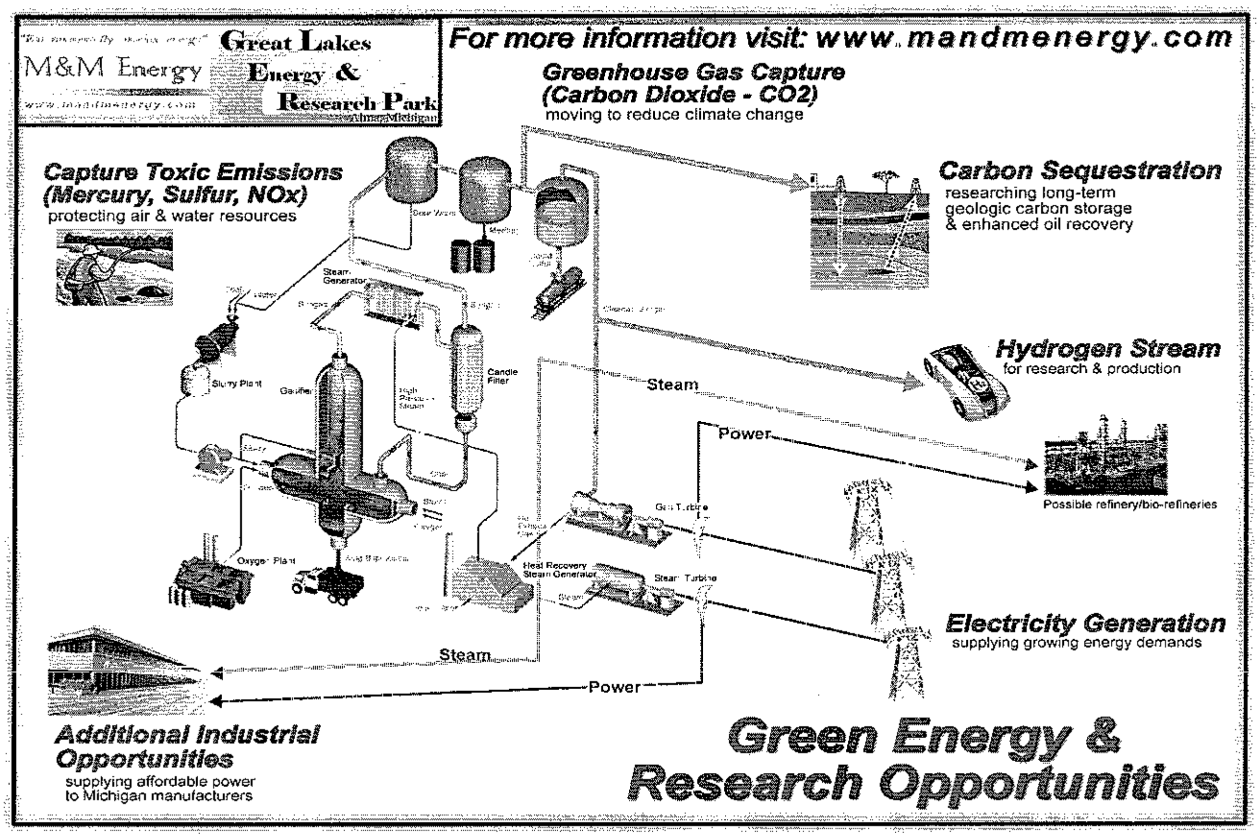
The governing and licensing authorities of the City of Alma, Gratiot County, and the State of Michigan as well as the Michigan Environmental Council are extremely enthusiastic and supportive about the possibility of additional available power, the positive environmental effects, and the economic benefits generated by the Project. Strong support by controlling and regulating authorities should assure that the permitting process is straightforward and timely. It is anticipated that all required permits will be issued within the two-year planned development timeframe.

In sum, the Project's IGCC-CCS plant, using clean coal-based technology to produce electric power and applying state-of-the-art techniques to capture CO_2 for permanent sequestration in connection with the EOR process, will provide unmatched economic and environmental benefits. The Great Lakes Energy Park's gasification power plant will be the first project to leverage greenhouse gases, and recover and process more of America's domestic oil resources.

Financing and Ownership Structure

The project sponsors have developed a plan of finance and ownership structure that will minimize the cost of capital while meeting the objectives and needs of the project participants. The IGCC facility will be jointly owned by a private consortium and the MPPA. The Michigan Public Power Agency was created in the 1970's for the purpose of undertaking the planning, financing, development, acquisition, construction, reconstruction, improvement, enlargement, betterment, operation or maintenance of a project or projects to supply electric power and energy for the present and future needs of its member municipality. The MPPA member municipalities serve retail load and, as a group, offer considerable credit strength.

The private consortium will consist of strategic and financial investors, including SemGreen, a member of the SemGroup family of companies. For tax and financing purposes, the Project's gasifier will be owned solely by Great Lakes IGCC, with no ownership of that part of the Project by MPPA or other public power entities, whose ownership interest is anticipated to be limited to the combined cycle portion of the project. Given the financial resources and commitments of the Project sponsors, the Project ownership structure provides a stable and reliable financial foundation that will ensure timely completion of the Project and utilization of tax credits allocated to the Project. Thus, the Project has secured more than sufficient land to allow for construction of the Project and its operation on a long-term basis



Project Participants

The key participants in the Project include the following:

- **Great Lakes IGCC, L.L.C.:** Great Lakes IGCC, LLC ("Great Lakes"), is the developer of the Great Lakes Energy Research Park "Project " Great Lakes is owned equally by SemGreen, L P. (a wholly-owned indirect subsidiary of SemGroup, L.P.) ("SemGroup") and M&M Energy, LLC ("M&M")

- **SemGreen, L.P.:** SemGreen, L.P. is a majority-owned subsidiary of SemGroup, L.P. SemGroup is one of the largest privately held companies in the United States. As of December 31, 2005, total assets amounted to approximately $3.6 billion with long-term debt of just under $1 billion. Revenues for the year ended 2005 were over $20 billion with EBITDA (excluding extraordinary items) of $395 million The ownership group of SemGroup includes Carlyle/Riverstone (32%), a premier U.S. private equity firm with investments in the energy and power sectors. SemGroup's principal business is to provide gathering, transportation, storage, distribution, marketing, and other midstream services primarily to independent producers and refiners of petroleum products located along the North American energy corridor from the Gulf Coast region and Mexico to central Canada

- **M&M Energy:** M&M Energy is a Florida-based energy management company. M&M Energy is teamed with Great Lakes IGCC in the development of the Project The principals in M&M Energy, LLC are J. Michael Muckleroy, Chairman and CEO and Michael Sawruk, President and COO, who collectively are experienced energy project developers and have the experience and capabilities to complete a project of this magnitude and complexity.

- **Michigan Public Power Agency:** The Michigan Public Power Agency is a non-profit, customer owned, joint action power supply agency established in 1976 under Michigan Public Act 448 It currently has 14 municipal members and is involved in joint ownership of electrical generating plants and transmission facilities, as well as pooling of utility resources.

- **SemCrude, L.P.:** SemCrude, L P. ("SemCrude") is a subsidiary of SemGroup. SemCrude is headquartered in Tulsa, Oklahoma and gathers, stores and markets crude oil and condensates. The company maintains a strong presence in North America's central energy corridor and is a leading transportation services provider in the Gulf Coast area, moving more than 70,000 barrels per day to market.

- **WorleyParsons:** WorleyParsons is an international engineering and construction firm with specific expertise in the development, design and construction of gasification process units WorleyParsons has provided coal gasification and fluidized bed design and support contractor services for the last 25 years to DOE as well as the Electric Power Research Institute, the Institute of Gas Technology, and to domestic and off-shore private utilities corporations.

- **Conoco-Phillips, Inc.:** Conoco-Phillips, Inc ("Conoco-Phillips") is an international, integrated energy company headquartered in Houston, Texas Conoco-Phillips is the owner of E-Gas technology for gasification and possesses over 15 years of proven commercial experience in IGCC applications.

IV. Project Status and Ability to Meet RFI Timeframe

The Project has been in development for approximately 28 months. During this time, the Project partners have secured a site, negotiated a land purchase agreement with the City of Alma, Michigan, and private parties, developed terms for Project agreements, begun the process for obtaining interconnection and transmission service and firm off-take agreements, developed a financial structure and met with all applicable local, state and federal regulatory contacts. A Power Purchase Agreement (PPA) is under active negotiation and is expected to be executed within 90 days.

The current project schedule includes a summary timeline of key Project activities and the schedule for the Project's development. With preliminary project development substantially completed, the Project can meet the timeframe set forth within the U.S. DOE RFI.

V. Funding Requirements

The total plant cost for the project is estimated at $2 15 billion. This includes licensing fees, front end engineering, start-up costs, and permitting, legal, financial, and technical expenses. The project reflects current pricing and engineering estimates for IGCC and the cost is appropriately sized for a Project of this complexity. The estimated amount of U.S. Department of Energy contribution that would be required for the completion of the project is approximately \$250 – 300 million or 12 - 14% of the total project cost.

VI. Consideration for Other Advanced Coal Technology Systems

Great Lakes IGCC recommends the revised FutureGen approach concentrate on IGCC rather than allowing for other advanced coal technology systems at this time. IGCC offers other degrees of freedom through the intermediary, syngas, which creates an opportunity for different directions of use including as a boiler fuel, synthetic liquid fuel, or for chemical products. IGCC has inherent fuel feedstock flexibility as well as demonstrated ability to minimize discharge of pollutants such as sulfur and mercury.

VII. Comments on Decoupling Power Generation & Carbon Transport and Storage

It is reasonable for the carbon transport and storage of CO2 to be decoupled from the power generation aspects of the project and performed by separate entities, as demonstrated by this project. This project, has in fact, already developed a broad base of diversified CO2 market uses utilizing partners who have significant Enhanced Oil Recovery experience. This is not unlike the current energy industry in which, for example, natural gas storage is decoupled from transportation. This "decoupling" of interests should allow for rapid deployment and commercialization of these technologies which will serve to accelerate development activities

VIII. Other Comments on Revised FutureGen

We feel very strongly that the revised approach to FuturGen development, i.e. a more diversified "portfolio" approach such as that under consideration will allow for a more robust development cycle, where different external factors such as geography and potential for carbon capture and sequestration are addressed. This should lead to more realistic "real world" solutions to clean coal technologies as well as carbon capture commercialization

Restructured FutureGen Initiative

Comments on the RFI from Mitsubishi Heavy Industries America, Inc.

The introductory sentence of the "Request for Information (RFI) on the Department of Energy's Plan to Restructure FutureGen" indicates that the intent of the restructuring is to, "... ensure that it more closely reflects the immediate and future needs of the Nation, its power sector and the taxpaying public." Mitsubishi Heavy Industries, America (MHIA) firmly believes the immediate and future needs of the Nation, its power sector and the taxpaying public will be best served by restructuring the FutureGen solicitation to include consideration of projects that propose to install post-combustion carbon dioxide equipment on existing coal-fired generating units.

While integrated gasification combined cycle (IGCC) technology with pre-combustion carbon dioxide capture promises to be an economically competitive option for new electricity generation facilities in a future carbon constrained world, it is likely that advanced pulverized coal-fired generation with post-combustion carbon dioxide capture will also be an economically competitive technology for new generating facilities. This is especially true if the new facility will burn lower rank coals. Furthermore, focusing exclusively on the IGCC option ignores the extensive fleet of existing pulverized coal-fired generating units. These pulverized coal-fired power plants represent a large percentage of the existing installed capacity. It is unlikely that new CO_2 limiting regulation can be met without reducing emissions from these existing plants. It is also unlikely that new generating capacity can be installed on a schedule to meet future demand for electricity without these existing coal-fired plants. Therefore, CO_2 controls must be installed on a large number of the existing and new build plants in order to meet the greenhouse gas reduction policy objectives while ensuring the Nation's energy security and economic prosperity. Furthermore, pulverized coal-fired units with post-combustion CO_2 capture can meet all of the emissions objectives of the restructured FutureGen initiative

Mitsubishi Heavy Industries (MHI) has been involved in the development of CO_2 capture technology using aqueous absorption and stripping since 1990. This involvement has resulted in development of an advanced, sterically hindered amine solvent (known as KS-$_1$) and an energy efficient process (known as KM-CDR). Together, these developments produce an approximately 30% reduction in energy consumption compared to the more conventional aqueous processes that use monoethanolamine (MEA) solvents. The KM-CDR process with KS-$_1$ solvent has been well received by the fertilizer and chemical industry, with four CO2 capture plants now in operation (one since 1999) and another three under construction. These systems are all installed on natural gas-fired applications and have a capacity of 450 metric tons of CO_2 per day (MTD) or less. In addition MHI has also completed a Front End Engineering Design (FEED) study for an 800 MTD plant and has performed conceptual engineering for a 3,000 MTD system, both on natural gas

MHI's experience with coal-fired flue gas, in comparison to natural gas, is much more limited. CO_2 capture with from coal-fired flue gas is significantly more challenging due to the associated impacts of a range of impurities and contaminants that are present in coal-fired flue gas streams. MHI built and operated a 1 MTD pilot plant in 2002 at its Hiroshima Research and Development Center. Later, a 10 MTD pilot facility was constructed at J-Power's Matsushima Power Station. The Matsushima pilot plant began operation in 2006 and has successfully completed a continuous 4,000 hour test campaign. During this campaign MHI confirmed and identified a number of specific impacts related to the effect of the impurities in the coal-fired flue gas on the solvent and the KM-CDR hardware. This enabled the development of possible countermeasures considered necessary to overcome these effects. MHI is continuing its testing at Matsushima as well as at its Mihara test facility. The Mihara facility is the world's largest multi-pollutant test facility, capable of performing various absorber based tests on flue gas streams with the equivalent volumetric flow of a 400 MW generating unit.

MHI believes its CO_2 capture technology is sufficiently proven for natural gas-fired CO2 capture applications. MHI's past experience in the development, design, and construction of world class flue gas desulfurization (FGD) systems (up to 1100 MW for a single module) also gives MHI confidence to offer commercial warranties for systems up to 3000 MTD on natural gas-fired CO2 applications. However, many questions remain to be resolved before a similar level of confidence can be reached for coal-fired applications and MHI (nor to our knowledge any other CO2 capture technology provider) is not in a position to offer the kinds of guarantees clients demand for the successful commercial deployment of coal fired CO2 capture plants. Therefore it is absolutely necessary that a demonstration of this technology, at significant scale, be accomplished as a matter of urgency. This will enable the engineering confirmation of impacts of the impurities and the development of effective countermeasures and would provide data necessary to more confidently predict cost and performance. MHI believe that facilitation and support of such a demonstration is a legitimate role for government. MHI is willing to participate and significantly contribute to such demonstration activity and for this and several other reasons we are requesting that DOE allows for post combustion CO2 capture projects to be considered for eligibility in the restructured FutureGen Initiative.

MHI responses to the specific RFI questions follow.

- Name, Point of Contact, Telephone Number, Mailing Address, E-Mail Address.

Mitsubishi Heavy Industries, America
Steven Holton, Senior Marketing Manager
(512) 419-5388 (O), (512) 804-8789 (Cell)
9400 Amberglen Boulevard
Austin, Texas 78729
steven_holton@mhiahq.com

- Location of project

MHIA is unable to identify a specific project and location at this time due to confidentiality concerns of our client. The potential project would be located on an existing coal-fired generating site and would have access to a sequestration demonstration site. Furthermore it would be conducted at significant scale that would lead to the future commercial development of CCS in line with the aims of the restructured FutureGen Initiative.

- Narrative description of project that includes the status of project development and the technical and financial qualifications of the project team to conduct the project.

  Confidentiality agreements are in place and the initial project development discussions have begun. In addition to MHI, the likely project team will include the highly regarded R&D staff of the host utility, technical support from EPRI, and technical support from a leading university. MHI is an internationally respected company with 2006 sales approaching 3,000 billion Japanese yen. The host utility is a large, well established electric utility based in the US with an equally large annual turnover.

- Discussion of the company's ability to meet or exceed the time frame set forth in the above schedule

  Because of the decrease in emissions from an existing, permitted site, the length of time required for initial permitting and construction activities should significantly favor the MHI project compared to a project that would involve a new generating source. If DOE selects the MHI project by the end of 2008, the project could be operational as early as the end of 2011, enabling the US to have the worlds first large scale demonstration of CCS on a coal fired installation.

- Estimated amount of DOE contribution (in percentage and/or dollars) that would be required for the company to pursue the project.

  The estimated cost of the project has not been determined at this time. However it is expected to be less than $US 200 million and will encompass the following scope; CO2 capture, compression and delivery to a pipeline, and operation for 4 years Furthermore, we believe that the host utility, MHI, and other contributors will fund from 25% to 50% of the total project cost.

- Any technological, financial, or legal issues or barriers that DOE should be made aware of that limit the effectiveness or feasibility of DOE's restructured approach to FutureGen

  MHI are aware of no issues or barriers that would prevent DOE from implementing a post-combustion CO_2 capture and sequestration project as a part of the restructured FutureGen activity

- Other information or concerns that would assist DOE in implementing the revised FutureGen.

  MHI has no additional information at this time but strongly believes that the restructured FutureGen approach will better serve the US coal-fired electric power sector by providing multiple funding opportunities for a diverse range of CCS projects encompassing both pre and post combustion technologies.

Thank you for the opportunity to respond to this RFI. MHI look forward to working with you on this very important demonstration project in the future

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TECHNOLOGIES

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Feb 28, 2008

Response to the Department of Energy's Request for Information on its Plan to Restructure FutureGen

First, I would like to congratulate the DOE on its decision to restructure the FutureGen program. The ability to separate CO_2 from syngas has been well proven, and the Weyburn EOR project demonstrates CCS for this application. For the DOE to bear the large financial burden of constructing a new IGCC plant that is essentially the same as either Wabash or Tampa, seems to be repetitive. It seems more prudent to pursue the current plan of action; develop more CCS infrastructure and demonstrate more CCS technology The problem for the coal industry and IGCC does not seem to be the development of technology for carbon separation, but the extended timeline to develop sequestration infrastructure.[1]

To use a cliché, ***The Future Belongs to the Efficient***. Never has this been more evident than today. IEA studies[2] indicate that CCS will require 25 to 30% more energy than non-capture plants of the same capacity. This equates to more coal consumption, and more CO_2 for disposal. These trends will only serve to deplete energy reserves at a faster rate, lead to the need for larger CCS infrastructure, and require more saline aquifers for CO_2 storage.

Let's examine the CO_2 emissions from the United States. Figure 1 indicates that 6 billion metric tons of CO_2 emanated from the U.S. in 2006, and provides a breakdown of emissions from the various sectors[3].

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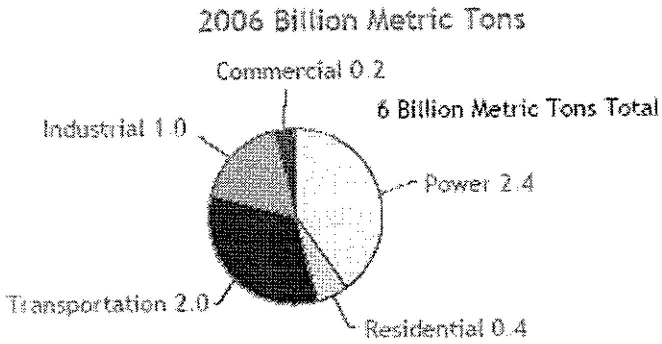
Figure 1: U.S. CO_2 Emissions



The power industry is clearly the largest emitter of CO_2. The transportation industry is a close second. However, the automobile industry is making great strides to lower its CO_2 footprint. As well as providing more efficient vehicles, the automobile manufacturers are turning to electric drive vehicles. Several plug-in hybrids are slated for production in the 2010 timeframe, as well as the Chevrolet Volt, an electric vehicle with a 40-mile all-electric range, and an onboard ICE (internal combustion engine) to provide electric power when the batteries are at a low state of charge[4].

Bob Lutz, Vice Chairman of Global Product Development at General Motors, has stated, "The electrification of the automobile is inevitable"[5]. Thus he has championed the Chevy Volt. Designed as a mid-size sedan, this car would provide transportation for most Americans to commute to and from work without the need for any gasoline. When the gasoline engine is needed, this car achieves about 50 mpg. It can travel 40 miles on 8 kWh of electricity in its all-electric mode.

Based on 15,000 miles per year and an average of 25 mpg, the typical mid-size sedan consumes 600 gallons of gasoline per year. With the Volt, assuming 2/3 of the miles driven are on electric power, 1/3 on gasoline, annual consumption reduces to 100 gallons of gasoline per year. Electric powered miles come at a cost of nominally $0.02 per mile, versus $0.12 per mile for gasoline in today's typical mid-size sedan. If 100 million vehicles like the Volt were employed in lieu of the current 25-mpg sedans, gasoline consumption would drop by 3.25 million barrels per day. Carbon emissions would be reduced by 530 million metric tons per year[6].

For residential/commercial heating and cooling, Public Service of New Hampshire is promoting geothermal systems. They state that customers can heat their premises for $0.49 per square foot, versus the typical average of $1.20 per square foot with fossil fuels. Again, these sectors of the economy are using methods to reduce their use of fossil fuels.

However, all of these sectors, commercial, residential, and transportation, are reducing their *direct* greenhouse gas emissions by converting to electricity. However, if the

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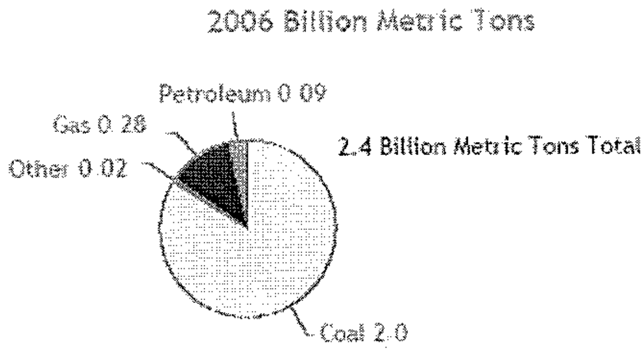
incremental power required for these sectors comes from the existing coal fleet at a nominal 33% efficiency[7], then their *indirect* CO_2 emissions may in fact be greater than the direct use of fossil fuels. This phenomenon is better understood after reviewing Figure 2[8].

Figure 2: U.S. CO_2 Emissions from Power Generation



So, not only does the power segment of the U.S. produce the most CO_2, coal-derived power produces 83% of those emissions. Therefore, with other segments of the economy turning to the power industry not only for low-cost energy, but also for reduced greenhouse gas emissions, it is obvious that the coal-fired power in this country (and globally as well) must be more efficient and emit less CO_2.

Currently, industry is looking to IGCC, coupled with CCS, to provide the answer. However, it is clear from numerous studies that the capital costs and fuel costs for this arrangement will be considerably more than non-CCS facilities[9]. In addition, there are only limited opportunities for EOR at this time. In the Texas Basin, approximately 7 million tons per year of CO_2 are consumed for EOR, which is equivalent to the CO_2 produced by a single 1000 MW conventional coal plant. With 300 GW of installed coal capacity, there is clearly a need for vastly more sequestration sites.

In addition to IGCC, CTL plants may also be constructed in the future, as recent spikes in oil prices make their products financially attractive. The Department of Defense has also indicated an interest in CTL facilities, as they can reduce dependence on foreign oil. However, CTL facilities emit large quantities of CO_2, and they also will need to take advantage of CCS technology.

To repeat the cliché, ***The Future Belongs to the Efficient,*** can be evidenced by the Public Utilities Regulation and Policy Act of 1978. This legislation included a process for more efficient use of energy, namely, cogeneration (which is also known as combined heat and power, CHP). This process allows for the co-location of power generation equipment, namely heat engines, with facilities that have thermal loads. With this co-location, low-level heat from the engine(s), which is typically dumped to ambient in a

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power-only application, can also provide thermal load requirements, thus displacing the fuel normally required by the host facility. Fuel utilization rates for these types of applications can approach 90% with proper integration.

Thus, the question becomes, *how do we make the most from our coal reserves?*

Proprietary Information in this section not supplied

In summary, the FutureGen scope is changing to include funding for the demonstration of CCS technology. This is a necessary step, as some scientists consider global warming an immediate and serious threat. This includes Jim Hansen, Director of the Goddard Space Science Laboratories, who feels that the Earth's environment may be reaching a "tipping point", where the environmental damage could be irreversible. He has called for a moratorium on new coal plant construction, and a 20-year phase out of existing coal plants.

The implementation of CCS could make coal acceptable, however, the goal of CCS should not be to just pump enormous quantities of CO_2 into the ground. The goal should be to find the cleanest, most efficient, and most cost effective means to utilize an abundant natural resource such as coal.

Many countries, including the U.S., depend upon coal as one of its primary energy sources. Therefore, a clean, more efficient, and more environmentally friendly conversion of coal will help to maintain low energy prices, lower emissions, and significantly reduce greenhouse gases around the globe.

Regards,

William S. Rollins

William S. Rollins, PE
President

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[1] "CO_2 Capture-Ready Design for Power Plants", by Richard Klover of Burns and McDonnell. Presented at the 2007 PowerGen International Conference in New Orleans

[2] "Energy, Climate Change, and Coal – Towards Zero Emissions Technologies", by Kelly Thambimuthu of IEA, presented at the Pittsburgh Coal Conference 2005

[3] "Carbon Dioxide Regulation, and Its Effect on the Electric Utility Industry", by E. Couppis, M. Gewalt, V. Hahn, and R. Moe of R. W. Beck. Presented at the 2007 PowerGen International Conference in New Orleans

[4] See website www.gm-volt.com for more information on the Chevy Volt

[5] "Bob Lutz: The Man Who Revived the Electric Car", by Keith Naughton of Newsweek. Updated Dec. 22, 2007. See http://www.newsweek.com/id/81580

[6] See www.fueleconomy.org. Click on "New 1985-2008 MPG estimates". For a typical sedan, select the 2008 Chevrolet Malibu with the 4-cylinder engine. Its average fuel economy is approximately 25 mpg and carbon emissions are given as 7.3 tons per year

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[7] "Carbon Capture and Sequestration Abilities of IGCC Technology", by the General Electric Company. Presented at the 2007 PowerGen International Conference in New Orleans

[8] "Carbon Dioxide Regulation, and Its Effect on the Electric Utility Industry", by E Couppis, M. Gewalt, V Hahn, and R Moe of R W Beck Presented at the 2007 PowerGen International Conference in New Orleans

[9] "IGCC Cost and Performance Current–Day to Advanced Designs", by Julianne Klara of NETL Presented at the 2007 Gasification Technologies Conference in San Francisco

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NRG

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March 3, 2008

U.S. Department of Energy
National Energy Technology Laboratory
3610 Collins Ferry Road
Morgantown, WV 26507

Attn: Keith Miles

Re: NRG Energy Response to the Request of Information (RFI) on the Department of Energy Plan to Restructure FutureGen

NRG Energy, Inc. ("NRG") is a leading competitive power generation company, with a portfolio of over 24,000 MW of generation capacity that is distinguished by its range in geography, fuel source, and dispatch level. NRG has facilities in the Northeast, South-Central, Texas and Western regions of the United States. The company's facilities use a wide array of fuels, including natural gas, oil, coal and nuclear, across a balanced portfolio of base load, intermediate and peaking units. NRG procures over 30 million tons per year of coal and is the second largest buyer of low-sulfur coal from the Powder River Basin.

The United States faces two overwhelmingly urgent energy needs: we must increase our energy independence while also significantly reducing the climate impact of fossil fuel energy use. These objectives can be achieved through a national initiative to accelerate the development, commercial demonstration and deployment of clean coal technologies (CCT) with carbon capture and storage (CCS). NRG recognizes the need to reduce its own carbon footprint, and is a leading advocate of a mandatory cap-and-trade program to reduce greenhouse gas emissions. NRG also is pursuing cutting-edge projects in new technology, and seeks to develop closer partnerships with the Department of Energy in these efforts

This letter provides our views on a national initiative for the development, commercial demonstration and deployment of CCT/CCS technologies. Although these comments are being submitted in response to the RFI concerning the restructuring of FutureGen, NRG does not take a position as to whether or not the current FutureGen project should be restructured. In our view, the scope of the current RFI is too narrowly focused on the FutureGen project, and does not adequately consider the broader national policy goals of energy independence and greenhouse gas reduction. The continued use of coal is and will remain central to efforts to achieve U.S. energy independence, but it must be decarbonized to limit adverse impacts on climate. To achieve these goals, DOE and stakeholders need to come to a consensus on a comprehensive national climate change technology strategy that integrates the objectives of the FutureGen project, the Clean Coal Power Initiative (CCPI), the Carbon Regional Sequestration Partnerships (CRSP), the Innovations of Existing Plants program, the Title XVII Loan Guarantee program, and the EPACT 2005 tax credit programs

Our detailed comments are divided into two sections: (1) comments on the need for and the outlines of a comprehensive national strategy for accelerating CCT/CCS technology commercialization; and (2) information on current NRG projects that offer the basis for partnerships with DOE

A Strategy for an Expanded and Accelerated Program for Clean Coal

Technologies and Carbon Capture and Storage

The Case for Strong Federal Leadership: The use of coal accounts for over half of all electricity generated in the U S. While the portfolio of electricity generation technologies may shift in the future toward low carbon or carbon free energy sources such as natural gas, nuclear, wind, solar and other renewable energy sources , the abundance of coal reserves in the U S. ensure that coal will continue to be among the most economic energy sources for our economy Thus, any national effort to reduce greenhouse gas emissions must address the need to reduce carbon emissions from coal combustion, whether through retrofit of CCS technologies at current facilities or deployment of advanced clean coal technologies with integrated CCS features

There are a number of advanced clean coal technologies and CCS component technologies that have progressed through the R&D process to the point of commercial demonstration However, the pathway to commercial deployment is impeded by a number of factors: first-of-a-kind technical risk and first-of-a-kind equipment costs that are far above market prices for other generation technologies; the lack of a carbon price signal; and uncertainties surrounding the legal and regulatory framework for CCS applications. No single company can solely assume these risks, yet all will benefit once these risks and uncertainties are resolved and economies of scale are realized in producing CCS equipment. Thus, a strong federal role, through the Department of Energy, is needed to establish the appropriate partnerships with those companies willing to be leaders in de-carbonizing coal-fired electricity generation. By hastening cost reductions and the commercial deployment of the most promising CCS technologies, government investment will achieve large net economic and environmental benefits for consumers and taxpayers

The Need for an Accelerated Program: The enactment of a mandatory carbon cap-and-trade program will not, by itself, be sufficient to ensure the commercialization of CCT/CCS in a timely fashion. And, absent the ready availability of new low-carbon technology, compliance with mandatory emission caps will impose higher costs on the U.S. economy than necessary. An accelerated technology program, beginning now and achieving additional funding through climate change legislation, will ensure that significant greenhouse gas emissions reductions can be achieved at the least possible cost to consumers and disruption to the economy

NRG is convinced that with the right combination of legislative, regulatory and commercial incentives, coal-based CCS technologies can be ready for widespread commercial use by the end of the next decade. This would represent a significant acceleration of the current pace of technological development and would allow the U S to become a global leader in greenhouse gas emission reduction technology

Outline of the Major Parameters for a National Technology Strategy: Congress and the Administration have provided DOE with a variety of tools to bring new technology into the marketplace The FutureGen project, the subject of the current RFI, is only one approach. However, the DOE proposal to restructure the FutureGen project falls short of what is needed to achieve a comprehensive and expanded federal program The parameters for a comprehensive program should include the following:

- *Comprehensive scope of technologies*: DOE should provide strong support to all major categories of CCS technologies, including pre-combustion CCS technologies, such as Integrated Gasification Combined Cycle (IGCC), post-combustion CCS technologies and oxygen enriched combustion The RFI only addresses IGCC/CCS technologies. Also, DOE should support technologies that can be used in both retrofit applications and in new facilities.

- *Multiple Demonstration Projects*: DOE commercial demonstration efforts should support, in parallel, multiple projects in different regions of the country that reflect different combinations of technologies and coals. This will more rapidly achieve economies of scale, induce competition amongst original equipment manufacturers (OEMs) and better tailor technologies to different coal types, altitudes and geologies. In addition, CCS demonstration projects employing different geologic media are needed in order to develop a full understanding of performance and environmental issues

- *Emphasis on Commercial Application*: the DOE efforts should emphasize the objective of gaining early commercial experience as quickly as feasible There has been substantial previous investment in R&D on various technologies and technology components. The experience gained from early commercial demonstration projects will create learning-by-doing opportunities that will be a more powerful force for innovation than continued R&D to perfect technologies absent commercial demonstration Commercial demonstration projects also will provide the stimulus to expand manufacturing capability in order to lower costs, improve equipment performance and provide a firm basis to support subsequent broad commercial deployment.

- *Flexibility in Project Eligibility Criteria*: NRG supports the proposed objective to achieve commercialization of technologies that can attain 90% carbon capture and storage. However, we believe that the project selection criteria for the initial demonstration projects should be flexible, so long as the project sponsor can demonstrate to DOE that the technology can evolve to meet the DOE ultimate technical objectives. For example:

    - Demonstration of post-combustion retrofit technologies could be achieved on partial slip streams from existing generating facilities, so long as the scale of the project was sufficient to provide technical assurance that the technology can then be applied at full scale;
    - Carbon capture technologies could be initially demonstrated at lower levels of carbon capture, so long as subsequent projects could be upgraded to higher levels of capture; and
    - Demonstration projects using IGCC/CCS may not necessarily need to be at the scale of a 300 MW train in order to demonstrate commercial feasibility. While this scale appears typical for IGCC projects, there may be new or novel project configurations that could be accomplished at a smaller scale.

  DOE project eligibility criteria should emphasize the realization of the technical objectives of the demonstration program, and be less prescriptive of the means to achieve those objectives. This approach would reduce the technical risk and the cost to the government of proposed demonstration projects, while enhancing rapid realization of the DOE technical objectives.

- *Enhanced and Coordinated Federal Incentives*: The initial cohort of commercial demonstration projects will require federal incentives. The first-of-a-kind costs associated with these projects are far above those that can be covered by power sales and other revenue streams, such as sale of CO2 for enhanced oil recovery (EOR). The cost of large commercial demonstration projects also poses a challenge to existing DOE resources. The proposal for DOE to cap federal support at the level of the incremental cost of CCS technology for a single power train is too rigid and is unlikely to be the most cost-effective approach to funding demonstration projects. The economics of the project as a whole, including both capital investment and operating revenues and costs, need to be evaluated in the determination of the level of federal participation. For example, power and potentially EOR revenues can support a significant share of the cost of the project, leaving only the above-market cost portion of the project in need of federal support. This approach offers a more cost efficient way to achieve the DOE objective of significantly leveraging the number of projects that can be supported by a given pool of federal resources.

  Ensuring that the existing federal resources are applied in the most cost effective manner is a necessary but not sufficient condition. Additional federal resources, over and above current program budgets, are needed to achieve successful commercialization of CCT/CCS technologies. In addition, the use of federal cost sharing resources needs to be better coordinated with other federal incentives. A comprehensive program of increased funding for cost sharing, loan guarantees and tax credits can achieve effective, rapid deployment of CCT/CCS, with the attendant reductions in cost and timing to full commercialization. Optimization of federal financial incentives also will minimize total cost to taxpayers. Currently, these three types of incentives are being implemented as stand-alone programs, hindering efforts by companies to plan projects where the application of more than one form of federal incentive is needed to achieve a viable and cost effective solution.

- *Integration of CCS Technology and Regulatory Actions*: An accelerated program for implementation of CCS technology requires parallel implementation of technology, resource characterization and regulatory measures, such as:

  1. The early, competitive demonstration and deployment of critical mass generating facilities that actually capture CO2 for sequestration. These projects will of necessity focus on IGCC and emerging post-combustion technologies. Initial support for 5 to 10 projects to be completed by 2012, followed by strong financial incentives for up to 20 such projects that could be online by 2018, should be provided as part of climate change legislation, and the current funding approaches should anticipate this future source of funding.

2. The identification and utilization of saline aquifers, along with enhanced oil recovery (EOR), to sequester the CO_2 from all these projects on the basis of current best practices and the vast experience gained by existing EOR operators, natural gas transport and storage, and oil field services companies

3. The promulgation of a regulatory regime for geological sequestration that is safe, effective and commercially attractive, and that is designed in a manner that will not delay or encumber early CCS projects.

For CCS to be ready in time, each of these elements must develop in parallel, rather than sequentially. By contrast, a sequential approach – first one or two government financed pilot programs, followed by sequestration rule development, followed by technology improvement efforts – could easily add a decade or more to the commercialization of CCS. This would severely impair our nation's ability to effectively and timely slow the growth of greenhouse gas emissions.

NRG New Technology Initiatives

NRG is an industry leader in environmental stewardship and climate change mitigation. NRG has conducted detailed analyses of alternatives for new clean coal technologies and CCS technologies, and has selected a portfolio of technologies for demonstration and deployment. To date, NRG Energy has invested over $10 million of shareholder funds to advance new coal technologies aimed at reducing the carbon footprint of its electricity generation business. These technologies are now ready to proceed to commercial demonstration.

Federal incentives are needed in order to move these technologies into the demonstration process on an expedited basis. While NRG has implemented a number of risk mitigation measures, it believes that the residual technical and cost risk of these coal-based CCS projects are beyond the limits of conventional financing. Also, the uncertainties regarding future carbon emission caps (and a resulting carbon price) and a lack of a regulatory framework for geologic sequestration pose a significant barrier to private sector financing of these first-of-a-kind demonstration projects.

NRG is working on both pre-combustion and post-combustion CCS technologies. The following two projects, one pre-combustion and one post-combustion, are indicative of NRG technology leadership.

Huntley IGCC/CCS Project located in Tonawanda, NY

Description: This project is a 750 MW IGCC facility, located at the existing Huntley facility in Tonawanda, NY. This is a pre-combustion clean coal project that will incorporate the build-out of IGCC technology with the capture and storage of 65% of its CO_2 emissions. The project would demonstrate the Mitsubishi Heavy Industries ("MHI") gasification technology. The MHI technology uses dual-train gasifiers integrated with the MHI modified G technologies combined cycle power block.

Status and Schedule In December 2006, NRG received a conditional award in a competitive bid process with the New York Power Authority ("NYPA"). The conditions for the award are cost to NYPA and the prove-out of CCS capabilities for the project cost. Meanwhile, NRG, the New York State Department of Environmental Conservation, the New York State Museum and other state agencies have been working closely together in order to verify CCS capabilities. That work is on progress and NRG anticipates that this condition will be satisfied.

Cost and DOE Partnership Opportunity: The total capital cost for the proposed project is expected to exceed $3 billion. Because the cost of electricity generated from IGCC technology is well above the local market price, incentives are needed in order to make the project feasible. NRG believes that a combination of DOE cost sharing, as well as federal tax credits will be needed to supplement expected state and local assistance. NRG is prepared to respond to a DOE Funding Opportunity Announcement (FOA) in 2008.

Project Point of Contact Information:

Lee Davis
Vice President, New York Asset Management
211 Carnegie Center
Princeton, NJ 08540
(609) 524-4571
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Parish Post-Combustion CCS Retrofit Project at the W.A. Parish Facility near Sugar Land, TX

Description: This CCS demonstration project will be conducted at the NRG W A. Parish facility near Sugar Land, Texas, on flue gas equal in quantity to that from a 125 MW unit. The project will be designed to capture 90% of CO2 from the combustion boiler It is estimated that the demonstration will capture and sequester about one million tons of CO2 annually – ranking it among the world's largest CCS projects and potentially the first to achieve commercial scale capture and sequestration from an existing coal-fueled power plant Once captured, the CO2 is expected to be used in commercial EOR operations in the Houston area

Status and Schedule: Preliminary studies have been completed, and sufficient information is available to respond to a DOE Funding Opportunity Announcement (FOA) in 2008 The project is planned initiation of construction in 2009 with the facility to be operational in 2012

Cost and Partnership Opportunity: The estimated capital cost for implementation of the demonstration project is expected to be approximately $150 – 200M for carbon capture and compression equipment. NRG believes that the most appropriate partnership opportunity would be direct DOE cost sharing for a portion of the capital investment costs. Another portion of the capital investment costs and operating costs will be funded from revenues from the use of the compressed CO2 in EOR operations in the Houston area.

Project Point of Contact Information:

Will Stokes
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NRG Texas
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Will.Stokes@nrgenergy.com

Conclusion

We appreciate the opportunity to present our views and comments on this issue. Please let us know if we can provide any additional information on our CCT/CCS project opportunities We look forward to the opportunity to partner with DOE in advancing these projects

Sincerely,

John O'B

John O'Brien
SVP Regulatory & Government Affairs
NRG Energy, Inc

Pursuant to the Request for Information (RFI) from the Department of Energy (DoE) dated January 8, 2008 Power Holdings submits these comments.

Contact Information

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Location of Project
Blissville Township, Jefferson County, Illinois

Narrative Description of Project
Power Holdings has developed the Southern Illinois coal-to-synthetic natural gas (SNG) facility for the past four years. The facility will be located in southern Illinois, west of Rend Lake. The facility will operate at a mine mouth using approximately xx,xxx tons per day of coal to produce approximately xxx,xxx MMBtu per day of pipeline-quality SNG

The principal process components include coal gasification, gas purification, sulfur recovery, and methanation, and carbon capture. In addition, the facility will include major components for coal processing, air separation, power generation, and CO_2 processing. PH expects to begin construction of the facility in 2008, with testing and shakedown in 2011 and full operation in 2012. The facility will contract for sale of 100% of the base SNG output under 20-year contracts with investment-grade gas utilities.

The project includes full specification and configuration for carbon capture. The base design contemplates full capture of a sufficiently pure stream of carbon dioxide to permit complete sequestration, either in saline formations or in enhanced oil recovery (EOR) or similar operations. It will also generate a substantial quantity of carbon dioxide, approximately 6 million tons per year at full commercial operation. Power Holdings has also researched thoroughly sequestration and EOR opportunities, and has participated extensively in the deliberations of the Midwest Geological Sequestration Consortium. Finally, Power Holdings has negotiated with commercial users of carbon dioxide for EOR. We have a significant understanding of the issues, opportunities, and challenges associated with CCS.

The project has completed most of the commercial contracts needed to operate the plant. It has also completed substantially all of the technical design work needed to determine the necessary technology and processes. In late 2007 it began the front-end engineering design phase, including negotiations with a construction firm for an engineering, procurement, and construction (EPC) lump-sum, turnkey (LSTK) contract.

The project team includes founders with significant experience and expertise in the natural gas industry, including coal gasification (Robert Gilpin), energy finance (Stephen Shaw), and energy and utility regulation and law (Mark McGuire). It also includes an owners' engineer (Black & Veatch) with substantial experience and expertise in design and specification of coal gasification facilities. Finally, it includes a lead equity investor (Energy Capital Partners) with significant background in energy investing and project finance.

Timeframe
Power Holdings can meet the timeframe set forth in the RFI. We expect to begin actual construction on the facility in late 2008 or early 2009. We expect construction to proceed in two phases, with the first phase complete in approximately 2010, and the second phase in 2011. We expect start-up and shake down to take approximately one year, and to finish sometime during 2012, depending on when actual construction begins. This schedule allows the project to participate in the carbon capture and sequestration activities that the DoE

would like to begin in 2015.

Estimated DoE Contribution
Power Holdings expects its CCS process to include a number of elements, including:

1. carbon capture from methanation
2. compression
3. storage
4. pipeline shipment
5. injection
6. monitoring.

We do know that carbon capture, compression and storage (items 1., 2. and 3.) within our facility will entail capital costs of approximately $xxx million. At this time we cannot set forth with precision the cost for the other infrastructure elements (items 4., 5., and 6.), in part because we do not know the sequestration conditions, design, and equipment specification. Based on our knowledge of similar sequestration efforts, we estimate that full sequestration in reasonable proximity to the plant site would entail an investment in this infrastructure of $xxx-xxx million.

Based on the RFI, we would expect the DoE to provide financial assistance for this capital cost, and for subsequent sequestration costs.

Barriers that Limit Feasibility or Effectiveness
We can think of several potential barriers. First, CCS can become expensive, and we believe that operators will be more likely to implement CCS technology if they receive funding for a substantial portion of CCS costs This suggests that DoE should select a fewer number of appropriate projects, and fund more of the cost of these projects, rather than funding a smaller share of a larger number of projects.

Second, CCS can vary in its effectiveness depending on the proximate geology. DoE has indicated it will emphasize saline injection, with enhance oil recovery, enhanced gas recovery, or other uses as a secondary goal. Some attractive CCS opportunities may need to emphasize these latter uses because of the local geology, with little or no carbon dioxide sequestered in saline formations. This suggests that DoE consider the entire range of sequestration approaches, rather than emphasizing saline injection

Other Information or Concerns
DoE seeks comments on two such concerns. First, we strongly urge DoE to allow the revised FutureGen approach to allow for advanced coal technology systems, other than IGCC, that would meet the performance requirements set forth in the RFI. Numerous uses and applications of coal gasification technology, including the coal-to-SNG and coal-to-liquids, provide a valuable product while meeting the performance and economic goals envisioned in the original FutureGen mandate. These alternative technologies use a range of gasification and production methods, many of which will benefit from the full-scale commercial demonstration of CCS within their processes. Research shows that some gasification technologies, including coal-to-SNG and coal-to-liquids, provide an even higher volume and better quality stream of carbon dioxide than IGCC technologies. Indeed, we believe that DoE will miss a valuable opportunity to demonstrate the viability of CCS if it confines its funding only to IGCC projects.

DoE also seeks comment about decoupling of carbon dioxide generation ("capture") from transport and storage ("sequestration"). We think that while an integrated CCS approach may reduce somewhat the cost of a complete CCS process, decoupling will allow more than one generator to participate in sequestration in a given geology. We urge DoE to remain flexible in considering the structure of specific CCS proposals. It should allow both integrated CCS approaches, in which a single entity undertakes the complete CCS projects, and decoupled CCS approaches, in which multiple entities participate in carbon capture, and potentially one or more participate in sequestration.

We also wish to add that CCS entails two sets of costs: capture, which takes place within a gasification facility, and sequestration, which takes place outside of the facility. Above we highlight the different types of equipment and infrastructure needed for both, and note that the Power Holdings project already includes well-specified plans for carbon capture. We note that gasification projects of all types, including IGCC, coal-to-gas, and coal-to-liquids, will benefit from funding assistance that helps both with on-site capture equipment, and off-site sequestration infrastructure.

Powerspan Comments re: RFI on the DOE's Plan to Restructure FutureGen
Submitted to U.S. DOE National Energy Technology Laboratory/Keith Miles

Submitted by:
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Below are two comments to the RFI followed by a discussion of Powerspan's work in CO_2 capture technology development, including plans for a one million ton per year CO_2 capture commercial demonstration project. The information about Powerspan's work is included for DOE to understand Powerspan's perspective as a CO_2 capture technology developer that is committed to commercializing CO_2 capture technology as quickly as possible. Powerspan's two comments below are provided in the spirit of how to restructure the FutureGen program so that it can serve all companies actively engaged in commercially promising CO_2 capture technologies.

Under the proposed restructured approach to FutureGen, the NRG/Powerspan commercial demonstration project described below would not qualify because it is not IGCC-based, is under 300 MW and is targeting enhanced oil recovery as the most likely use for the captured CO_2. However this project is one of the largest, if not the largest carbon capture and sequestration (CCS) project announced to date. Demonstrations of this size are approximately $150-200 million each in capital investment Neither the generating company nor a technology developer can fund projects at this level of investment. Yet projects at this scale are required to bridge the valley between pilot tests (which can be funded by technology developers and the plant host) and full-scale units (which utilities will fund once regulations become clear). Without government support, these projects simply won't get done, and as a result, capture technologies will be delayed in commercialization Generating companies and technology developers are likely to be able to make a combined contribution of tens of millions to a demonstration project, and then, only if there is a revenue stream, as there would be if using enhanced oil recovery as the sequestration method.

COMMENT 1 – Technology Neutral

The RFI is wholly focused on gasification technologies. This pre-determination of a technology winner sets up a condition where highly promising projects of commercially viable technologies may have no real opportunity to get funded. Furthermore, over 99% of existing U.S coal-fueled power generation is PC-based with only two small IGCC plants operating in the US. Therefore the proposed restructured FutureGen approach focuses 100% of the funds to be made available on less than 1% of the existing market.

Recommendation

The selection process should be technology neutral and ensure that the most commercially promising CO_2 capture projects get funded.

Background
The nature of CO_2 capture technology is rapidly evolving, and multiple technologies will be needed to address the diverse asset base. Coal-based gasification technologies are not a viable option for the installed based of coal-fired, electric power plants, which currently produce 50% of our nation's electricity It is imperative that economically viable technologies, which can be retrofit to the existing fleet, be commercially demonstrated.

As supported by the 2007 MIT Study: The Future of Coal:

"A second high-priority requirement is to demonstrate CO_2 capture for several alternative coal combustion and conversion technologies. At present Integrated Gasification Combined Cycle (IGCC) is the leading candidate for electricity production with CO_2 capture because it is estimated to have lower cost than pulverized coal with capture; however, neither IGCC nor other coal technologies have been demonstrated with CCS. It is critical that the government RD&D program not fall into the trap of picking a technology "winner," especially at a time when there is great coal combustion and conversion development activity underway in the private sector in both the United States and abroad."

The study continues:

"... The reality is that the diversity of coal type, e g heat, sulfur, water, and ash content, imply different operating conditions for any application and multiple technologies will likely be deployed."

COMMENT 2 - Project Size
Minimum required size of a 300-MW unit would eliminate the opportunity for some promising commercial scale demonstrations to get funded A 300-MW unit presents unacceptable technical and financial risk for both the technology developer and the host site. To date, most demonstrations have been done at the pilot scale (1-5 MW), and an intermediate step (of approximately 100 MW/one million tons) is needed prior to a full-scale commercial installation.

Also, the requirement that the first million tons of CO_2 annually be stored in a saline storage formation may delay or eliminate the opportunity for the capture technology to be demonstrated. Powerspan and NRG are planning a one million ton CO_2 capture demonstration expected to begin in 2012, a few years prior to the 2015 operation timeframe identified in the RFI It is not clear that the regulatory structure would be in place in 2012 to support saline storage.

Recommendation
Modify the size requirement to be 90% capture and at least one million metric tons of CO_2 captured annually This equates to approximately a 100-120 MW size unit. This would still meet the capture goal of one million tons per year, while minimizing the capital investment. This size requirement would represent a reasonable scale-up from pilot demonstrations and a reasonable demonstration of commercial viability.

Relax the requirement for the first one million tons of CO_2 captured annually to be stored in a saline formation Demonstrations of commercially promising capture technology may be ready to proceed before the structure/framework is in place that would permit sequestration in saline formations.

__Background – Requirement from RFI__

The RFI outlines the program requirements for projects seeking funding as follows:
"The Department is interested in funding multiple demonstrations of CCS technology at a commercial scale of at least 300 gross MW per unit plant power train, per demonstration. . Approximately 90 percent CO_2 capture and sequestration for the integrated power train will be required. During the demonstration period (see below), at least one million metric tons of CO_2 per year must be stored in a saline storage formation; CO_2 in excess of one million metric tons may be used for enhanced oil recovery, enhanced gas recovery, or other uses that result in permanent storage of CO_2."

Background on Powerspan's CO_2 Capture Development and Plans for a 2012 Commercial Demonstration of One Million Tons CO_2 Captured per Year

Powerspan Corp., based in New Hampshire, has been focused on developing and commercializing clean coal technology since its inception in 1994. Powerspan's most significant clean coal technology success to date has been the development and commercialization of its patented Electro-Catalytic Oxidation (ECO®) technology, which is an advanced multi-pollutant control technology to reduce emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx), mercury (Hg), and fine particulate matter ($PM_{2.5}$) in a single system.

Powerspan has been developing a cost-effective CO_2 capture process, called ECO_2™, since 2004 in conjunction with U.S. DOE National Energy Technology Laboratory (NETL) under a cooperative research and development agreement (CRADA). Both DOE-NETL and Powerspan have research teams assigned to conduct bench-scale testing of the ECO_2 process. Initial laboratory testing conducted by Powerspan of the CO_2 absorption process demonstrated 90 percent CO_2 removal under conditions comparable to a commercial-scale absorber. In December 2007, Powerspan announced it had exclusively licensed a patent from the DOE. The patent granted to the DOE represents the only patent issued in the U.S. to date covering a regenerative process for CO_2 capture with an ammonia-based solution.

__Technology Description__

The ECO_2™ process can be applied to both existing and new coal-fueled power plants. The process is being designed as an add-on system that could be deployed when needed and is particularly advantageous for sites where ammonia-based scrubbing of power plant emissions, such as Powerspan's ECO multi-pollutant control technology, is employed.

ECO_2 is a scrubbing process that uses an ammonia-based (not amine) solution to capture CO_2 from the flue gas. The CO_2 capture takes place after the NOx, SO_2, mercury and fine particulate matter capture in Powerspan's ECO technology or other air pollution control system. Once CO_2 is captured, the resulting solution is regenerated to release CO_2 and ammonia. The ammonia is recovered and returned to the scrubbing process, and the CO_2 is processed into a form that is sequestration ready. Ammonia is not consumed in the scrubbing process, and no separate by-product is created.

__ECO_2 Pilot Program__

Pilot scale testing of the ECO_2 technology is scheduled to begin in 2008 at FirstEnergy Corp.'s R.E. Burger Plant in Shadyside, Ohio. The ECO_2 pilot will process a 1-MW slipstream drawn from the outlet of the 50-MW Burger Plant ECO unit and will be designed to capture 90% of the incoming CO_2 (approximately 20 tons per day)

The ECO_2 pilot will demonstrate CO_2 capture through integration with the ECO multi-pollutant control process. Operation of the pilot will confirm process performance and energy requirements. The pilot program will also provide the basis for cost estimates while preparing the technology for the 125-MW commercial scale carbon capture and sequestration (CCS) demonstration project planned with NRG Energy at the WA Parish plant.

ECO_2 Commercial Demonstration Planned for 2012

In November 2007, NRG Energy, Inc. and Powerspan announced their memorandum of understanding to commercially demonstrate the ECO_2 process at NRG's WA Parish plant near Sugar Land, Texas. The 125-MW equivalent CCS demonstration will be designed to capture and sequester about one million tons of CO_2 annually. The ECO_2 demonstration facility will be designed to capture 90% of incoming CO_2 and is expected to be operational in 2012. The captured CO_2 is expected to be used in enhanced oil recovery operations in the Houston area

Indiana Center for Coal Technology Research

Located in The Energy Center at Discovery Park, Purdue University

To: Keith.Miles@NETL.DOE.GOV

From: Marty Irwin, Director, Center for Coal Technology Research, and Office of Energy and Defenses Affairs, State of Indiana

Subject: "COMMENTS ON REVISED FUTUREGEN."

The State of Indiana strongly supports the DOE efforts to refocus FutureGen to invest only in the capture and store components of proposed projects. Otherwise the proposed projects should be commercially viable. We believe that this opens the door to a variety of alternatives that otherwise would remain unexplored.

Indiana is aggressively pursuing a family of clean coal options as part of its energy strategy. We have supported a series of analyses assessing the suitability of Indiana as a home for a variety of coal gasification-based industries, not just power generation. All of the options we have reviewed, in fact, produce a great deal of power. We have explored the gasification suitability of Indiana coals, our transportation and support infrastructure, and identification of the highest opportunity sequestration opportunities, among many others.

We already host one of the major successful gasification projects -- the Wabash River coal gasification facility. Through the Indiana Center for Coal Technology Research, we have provided funding for the SAIC Coal to Liquids feasibility study. Moreover, with the full support of the Governor's office, the Indiana Department of Environmental Management recently approved the permits for a 650MW IGCC power plant in Edwardsport, Indiana (explicitly designed as sequestration ready), and we are considering other gasification proposals.

With the potential of bringing multiple IGCC operations on-line, the state has entered into discussions with industry and government stakeholders about the potential for developing joint approaches to building sequestration infrastructure. Indeed, before DOE restructured FutureGen, we had agreed to collaborate with Illinois on their project.

The Governor supports and encourages each of the Indiana-based industry teams working on coal gasification projects to submit comments on the DOE RFI. Moreover, the State is committed to supporting industry responses to the RFI once issued, and will work with any projects that might be selected to participate in the FutureGen program.

Sincerely,

Marty Irwin

Marty Irwin
Director, Indiana Center for Coal Technology Research
Energy Center, Purdue University

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MICHAEL L. WILLIAMS
CHAIRMAN

February 27, 2008

Mr Keith R Miles
Department of Energy
National Technology Energy Laboratory
626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236-0940

Re: Comments on Restructured FutureGen RFI

Dear Mr Miles:

On behalf of the State of Texas, I am pleased to provide comments on the Department of Energy's restructured plan for FutureGen As the original FutureGen selection process has already demonstrated, Texas is an ideal location for these types of projects, and we encourage DOE to work with Texas-based companies submitting proposals

Please allow me to emphasize three key points:

1 The State of Texas has been a strong proponent of FutureGen since it was announced in 2003 We continue to support DOE's restructured plan for FutureGen, which we believe will enable us to commercialize a variety of effective methods for mitigating carbon emissions through capture and sequestration and carbon minimization. In addition to gasification, we believe the restructured program should allow other advanced coal technology systems to be eligible

2 In keeping in the spirit of the restructured plan, the State of Texas recommends your final RFP be a flexible one that establishes an objective and allows the marketplace to offer a variety of ways to get there IGCC may only be one method to successfully capture CO_2 Other advanced technologies should be eligible and these may also be applicable for retrofitting existing coal-fueled generating plants, and these plants should be eligible if they can meet a 50 percent, carbon-capture standard, which would be roughly equivalent to the performance of a natural gas-fueled generator

3 Texas is ideally suited for these projects We have the geology, the CO_2 pipeline infrastructure, and the public and political support to make this project a success In my capacity as chairman of the Railroad Commission of Texas, I will continue to encourage Texas companies to submit proposals

The revised DOE model for FutureGen closely resembles what we envision for clean coal projects in Texas. By investing in many different projects at once, DOE will be speeding up the full-scale rollout of these technologies In some cases we might even be able to eliminate the gap between the research phase and commercial production altogether

This important effort is best served if the process is open to all methods of carbon capture Gasification may only be one way this country ultimately addresses carbon capture We also ask DOE remains cognizant of the value of lower rank coals, such as lignite, as feedstocks that qualify for these projects Texas is currently the fifth-largest coal producer in the nation with a majority of production in lignite We believe this is a valuable, if underappreciated, energy source

As you know, Texas Governor Rick Perry submitted two strong finalists for the FutureGen project last year As chairman of the state's FutureGen Advisory Board and the Clean Coal Technology Council of Texas, I can assure you those submissions were made possible by a strong coalition of industry, academia and elected officials stretching from local levels to the state legislature

Ultimately, nine regional Councils of Government (COGs) in Texas submitted complete proposals for the project These proposals included the necessary economic, geologic, and community data DOE required. I should also note at least twice that many COGs showed initial interest, yet did not submit formal proposals

The fact that so many different groups across this state showed interest in FutureGen speaks volumes about the support Texas has for clean coal demonstration projects in this state In addition to the strong community support Texas has for FutureGen and FutureGen-like projects, we have the land, the infrastructure, and the know-how few other states can offer We look forward to utilizing all of Texas' assets to their fullest potential

You may already know Texas and our Gulf Coast region have the largest saline aquifer storage capacity of any state This has been demonstrated by the successful DOE-University of Texas Frio Brine carbon capture research project currently under way under the direction of the UT Bureau of Economic Geology

In addition, the draft RFI clearly points to another Texas strength when it states:

"CO_2 in excess of one million metric tons may be used for enhanced oil recovery, enhanced gas recovery, or other uses that result in permanent storage of CO_2 "

Texas is the worldwide leader in enhanced oil recovery In fact, EOR in the state's Permian Basin accounts for the majority of the oil recovered in Texas We have an extensive pipeline network designed for the transport of CO_2 that would be perfect for both EOR and long-term sequestration

Texas has also passed important pieces of legislation tailored specifically for FutureGen and FutureGen-like projects in Texas House Bill 2201, passed in 2005, gives the state ownership of CO_2 sequestered by FutureGen House Bill 3732, which became law this year, creates "time-certain" permitting for clean energy projects These permitting limits help ensure new projects go online, on-budget, and in a timely manner The same bill offers up to $30 million in grants, as well as tax incentives for electricity generated by clean energy projects and man-made CO_2 used for EOR Combined with financial assistance from DOE, Texas has positioned itself as the ideal incubator for these technologies to develop and flourish

Under the restructured program, the State of Texas is committed to offer public outreach and support to any Texas FutureGen project selected by DOE In addition, we will bring our legislative and state regulatory resources to bear in support of any Texas project selected On behalf of all of us who worked so hard to make FutureGen a reality – and I am including our colleagues in Illinois – I urge DOE to stay committed to this restructured FutureGen plan The project remains vitally important to this nation

Please don't hesitate to call if my office can be of further assistance

Sincerely

Michael L Williams
Chairman

Raven Energy, an Illinois Coal-to-SNG Project
Raven Deeps, an Illinois CO2 Saline Sequestration Project

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1.0 Project Summary

The Cline Group ("Cline"), one of the largest owners of coal reserves in the Illinois Basin and an active participant in the coal mining sector, is currently developing the Raven Energy Project ("Raven Energy"), a coal-to-SNG (Substitute Natural Gas) plant in Illinois. Expected to come on-line in 2012, Raven Energy will gasify approximately ____________ tons of coal produced in the Cline's Illinois mines, and is expected to produce approximately __________ cubic feet per day (mmcfd) of SNG, or ____________ cubic feet (bcf) per year of SNG at full production – enough SNG to generate approximately 650 MW of electricity when that fuel is used in NGCC power plants across the nation. Utilizing the most advanced commercially-proven and available technology, Raven Energy is designed to be permitted, constructed and operated as a synthetic minor source (less than 100 tons per year of regulated pollutants including NOx, SOx, CO and PM10)

To address the uncertain future of carbon legislation and the potential impact that a new regulatory regime might have on its Raven Energy project, Cline has performed initial feasibility work and has commissioned a detailed engineering study to determine the potential to sequester CO2 in saline aquifer reservoirs co-located with its property rights. Dubbed "Raven Deeps," this early work performed by Cline has identified significant potential to sequester CO2. Through its participation in the Midwestern Geologic Sequestration Consortium ("MGSC") and interaction with various Illinois stakeholders and regulators, Cline is monitoring the current studies being funded by U.S Department of Energy ("DOE") grants. Cline submits these comments on the DOE's present Request for Information ("RFI") because it intends to seek DOE funding for the Raven Deeps CO2 sequestration project. In the absence of DOE funding of the Raven Deeps project, Cline will continue to track legislative and legal developments, but would only initiate the Raven Deeps project if/when significant economic incentives emerged and these incentives were coupled with regulatory certainty regarding the sequestration of CO2.

The Raven Energy Project is currently co-located with Cline's Williamson Energy mine in Franklin County, Illinois. Cline currently controls or has access to surface property, water, utility and pipeline interconnects, rail transport, and long-term coal supply adequate for the successful development of the Raven Energy project at Williamson Energy. Moreover, Cline has initiated permitting activities at this site.

If DOE offered sufficient support to mitigate the cost to Raven for advancing its CO2 sequestration program, Cline would move the Raven Energy project to the Raven Deeps project area, where Cline controls approximately ________________ tons of coal reserves and additional real property and mineral estates. Cline is already in advanced development of a mine in the Raven Deeps area. Locating the Raven Energy project at Raven Deeps would mitigate the cost of CO2 compression and transportation for all involved. Cline anticipates working with the DOE and the State of Illinois to facilitate the relocation of Raven Energy

Raven Deeps offers the potential to validate commercial sequestration into multiple saline aquifers (Mt. Simon and St. Peter Sandstones) that are excellent CO2 sinks, offering the reservoir properties needed to store and confine CO2. Preliminary engineering calculations indicate that the Raven Deeps project has the capacity to sequester more than two billion tons of CO2 in the area over which Cline has property rights in central Illinois. The Raven Energy project will produce approximately ________________ tons per year of 99% pure CO2 suitable for sequestration. With appropriate support from DOE and the State of Illinois, Cline would fast-track the development of the Raven Deeps project with the expectation to begin commercial CCS operations in 2012-2013. Significant technical work that has been completed or is currently underway will enable this partnership to beat the proposed DOE timetable. Selection of this project site will allow efficient technology transfer and permitting know-how from the MGSC/DOE co-sponsored Decatur, Illinois saline sequestration pilot project.

1.1 Summary Comments on DOE RFI

Cline recognizes that the DOE's RFI explicitly solicits proposals demonstrating carbon capture and storage ("CCS") coupled with integrated gasification combined cycle ("IGCC") power generation. This is a narrow path upon which to support the development of commercial-scale CCS projects.

The SNG-CCS model proposed, with the product SNG utilized for natural gas combined cycle (NGCC) power generation, breaks down an IGCC-CCS project into two separate components that can be performed at two distinct locations. This de-linking of SNG production/carbon sequestration from power generation offers several advantages.

The principal advantage is one of location. In Illinois and across the nation, less-developed rural areas (often near coal mines or oil fields) are the most suitable sites for CO2 sequestration. These optimal sequestration areas are far from urban centers where demands for power are highest. Placing IGCC power plants in rural areas best-suited for CO2 sequestration requires most of the power generated in such locations to be transmitted for consumption in more populous regions. This necessarily involves significant transmission losses. Locating an IGCC-CCS facility near more urban areas would reduce power transmission losses, but would drive up the costs of (1) transporting coal to the plant, and (2) sequestering CO_2, which would be pressurized (operational cost) and piped (infrastructure cost) to appropriate sequestration locations.

In contrast, the SNG-CSS model allows carbon sequestration and coal-to-SNG conversion near both the carbon storage site and the coal source, with only the transport of SNG product to NGCC plants near urban areas. This enhanced flexibility to site the distinct production processes at optimal locations allows SNG-CCS to drive down total costs (and drive up project returns) when compared to IGCC-CCS. SNG-CCS is a more durable and robust model than IGCC-CCS, and therefore more likely to receive support from the private sector.

SNG-CCS offers other advantages when compared to IGCC-CCS. First, the construction and funding of this business model requires no explicit approvals from public utility commissions and has no measurable impact on rate-payers due to the rate-basing of such a large capital project. This speeds the development cycle, resulting in a quicker-to-market project than would be available in the power sector, in turn leading to earlier demonstration of commercial-scale CCS. The Raven Energy Project discussed above is slated to be operational in 2012, with CO_2 sequestration (if funded) on line that same year. Second, the purity of feedstock required by the SNG process necessitates such a reduction in sulfur that the resulting CO_2 is of high enough purity to sequester without additional cleanup. For most IGCC process designs, additional gas cleanup (and therefore additional capital outlays) would be required to produce CO_2 of sequestration-ready purity. The difference between "capture-ready" and "capture-capable" is an important distinction to make. Third, in addition to expediting the achievement of critical environmental goals, a CCS-SNG project will strengthen the nation's energy security by reducing the need to imported liquefied natural gas.

SNG production coupled with CCS is the first step in mitigating emissions of regulated pollutants and greenhouse gasses. This technology is both commercial and executable in today's environment. By in effect making coal as clean-burning as natural gas, significant reductions in NOx, SOx and mercury emissions are achieved. Likewise, the carbon footprint of coal (the heaviest carbon fuel), is reduced to that of natural gas (the lightest carbon fuel). While hydrogen plants and capture of post-combustion CO_2 are technologies in various states of readiness, the DOE is seeking to achieve its core goals and encourage the private sector to deploy of the next wave of technology that reduces our nation's emissions. Supporting actionable projects that can be financed in today's environment, such as the Raven Energy / Raven Deeps projects described herein, would be the quickest route to implementing the DOE's goals.

In short, Cline encourages the DOE to consider alternative technology combinations that maintain the core principles expressed in the RFI of coupling CCS with the next generation of gasification technology. Below is additional information on the Raven Energy and Raven Deeps projects, including the applicability of these projects to the goals stated by the DOE in its RFI, the anticipated involvement from the DOE to fast-track the development of Raven Deeps, and a preliminary discussion of regulatory and legal issues that present obstacles for private enterprises like Cline in developing a saline aquifer sequestration project. The Cline Group appreciates the ability to comment at this early stage and looks forward to discussing its projects in more detail in the coming months.

2.0 Sponsor Background Information

The Raven Energy Project is a development-stage Illinois coal-to-SNG project. The Raven Deeps Project is a separate but associated saline sequestration project. These projects are being sponsored by Raven Energy, LLC ("Raven"), a wholly owned subsidiary of The Cline Group ("Cline"). Cline is a private natural resource company with over 35 years of operations and project development experience in the coal mining sector. With over three billion tons of controlled reserves, today Cline is one of the largest coal reserve owners in Illinois. In addition to its existing active mines in southern Illinois and West Virginia, Cline is developing numerous new coal mining operations in Illinois to address the nation's growing need for solid fuels. Table 1 summarizes the physical assets and recent activities of the Cline Group:

Table 1 – Cline Group General Activity Summary

[______________________________]

3.0 Raven Energy Project Description

The Raven Energy project will gasify approximately ________________ tons per year of coal produced from Cline's Illinois mines and produce approximately __________ of SNG per year, or enough SNG to generate 650 MW of electricity. Pipeline-quality gas from Raven will enter the interstate pipeline system, infrastructure from which generators and industrial users across the nation currently source their fuel. Raven will utilize best-in-class, commercially available and proven technologies from reputable technology licensors. The preliminary process flow diagram developed by engineering firm SNC-Lavalin is shown below. Raven will meet all of the standards to comply with a synthetic minor air permit, producing less than 100 tons per year of currently regulated pollutants, including NOx, SOx, CO and PM10. Carbon dioxide produced by the plant emerges from the Acid Gas Removal section at 99% purity and is suitable for sequestration. Under today's regulatory regime—under which CO2 is not considered a pollutant—Raven will process the CO2 stream to 99.99% purity for venting. Additional technical information on Raven Energy can be made available to the Department of Energy on a confidential basis as needed.

Figure 1 – Raven Energy Preliminary Process Flow Diagram

[________________________________]

4.0 Raven Deeps Project Overview

Raven Deeps is a separate but associated project that grew from the need to deal with the impact of regulatory uncertainty on the Raven Energy project. Leveraging information gained through its participation in the MGSC, Cline personnel evaluated the potential to sequester carbon in saline aquifers, organic shale, deep coal seams, and oil fields adjacent to its mineral interests. Cline's analysis showed that saline aquifers presented the most mature and currently-feasible method of developing commercial-scale CCS.

Today, Cline has undertaken significant work identifying and quantifying the potential to sequester CO2 in the saline-filled St. Peter and Mt. Simon Sandstones in central Illinois, where Cline owns property rights on over ____________ acres. These geologic units are two of the most widespread saline reservoirs in the Illinois Basin. Over the Raven Deeps project area, both units exhibit excellent thickness, reservoir properties, and vertical seals, making them ideal CO2 sequestration targets. Preliminary calculations based on present subsurface and reservoir studies suggest that the Cline acreage could store in excess of ________________ tons of CO2 in the St. Peter and Mt. Simon Sandstones.

Considering operational risk, both the St. Peter and Mt. Simon units are routinely utilized as gas storage reservoirs throughout northern and central Illinois due to exceptional reservoir porosity and permeability. These characteristics allow the injection and storage of gas in both units with confirmation of effective vertical seals. The overlying Eau Claire and Davis Shales effectively seal the Mt. Simon, while the Maquoketa and New Albany Shale cap the St. Peter.

In addition to these natural benefits the Raven Deeps area, there is minimal oil and gas production and activity in the area. This would allow deep saline sequestration on a relatively unimpeded basis from an operational perspective. Rarely would it be necessary to coordinate drilling through a producing oil or gas reservoir in the project area. Cline would anticipate utilizing both of the above-described saline reservoirs for the Raven Deeps project to reduce the footprint and capital requirements of the sequestration project.

4.1 Raven Deeps Work to Date

Cline has initiated geologic and engineering studies which confirm the validity of saline sequestration in the Raven Deeps target area. The geologic parameters necessary for sequestering and confining CO2 in the St. Peter and Mt. Simon Sandstones have been verified by extensive subsurface work performed by Cline personnel and by a proprietary geologic study and mapping project completed by Marshall Miller & Associates (MMA) for Cline. MMA is an active partner and investigator in the SECARB regional carbon sequestration partnership

Currently, Schlumberger Data and Consulting Services is preparing a detailed reservoir engineering analysis over these Central Illinois holdings. Schlumberger is heavily involved in CCS, including an investigative role in the DOE-sponsored Decatur, IL deep saline sequestration pilot project. The Schlumberger reservoir simulation will predict the lateral migration of the CO2 plume in both the St. Peter and Mt. Simon Sandstones based on the planned injection rates and reservoir volumes to be occupied by CO2. This Schlumberger study will also consider injection and monitoring well patterns, related pipelines and facilities, and operating parameters of the sequestration project. Cline plans to use the results of this analysis to provide a technical basis for cost estimation and operational parameters for a DOE-sponsored CCS project.

Additionally, Cline's membership in the Midwestern Geological Sequestration Consortium (MGSC) and active mining concerns facilitate a relationship with the Illinois State Geological Survey personnel. This relationship has afforded Cline valuable feedback and information on statewide saline sequestration investigations, including the Decatur, IL deep saline sequestration pilot project in the Mt. Simon Sandstone.

4.2 Raven Deeps Project Activities Included Under DOE Partnership

The following is a general list of CCS project activities that Cline proposes be completed and funded (or reimbursed) through a saline sequestration partnership with DOE:

- Geologic, hydrogeologic, geochemical, reservoir, and other engineering studies necessary to confirm the suitability of the reservoirs for sequestration and simulate or model the operation and performance of the project
- Land, legal, personnel costs associated with securing and confirming sequestration rights
- Costs associated with the saline sequestration permitting process
- Permitting, acquisition, processing, and interpretation of 2D & 3D seismic data to further characterize the St. Peter and Mt. Simon reservoirs, confirm vertical seal stability, and predict CO2 migration pathways via geologic structure
- Drilling of test wells, and affiliated data collection or test injection/monitoring, as required in the reservoir characterization and permitting processes
- Project scale drilling and infrastructure
    - Injection wells & surface equipment
    - Monitoring or measurement wells & surface equipment
    - Compression and related facilities
    - Flowlines, gathering, processing, and related surface facilities

- Operating costs for all wells, gathering, compression, and processing facilities
- Capital, installation, and ongoing costs associated with an appropriate or mandated Measurement, Monitoring and Verification (MMV) program, which may include all or portions of the following for baseline, active, or post-injection CO2 confinement assessment:
    - Shallow earth geophysical methods
    - Geochemical, soil , groundwater, and surface CO2 monitoring
    - Ongoing well logging/testing for borehole stability confirmation
    - 4D seismic and vertical seismic profile to track plume migration
    - Construction and implementation associated with a mitigation plan

5.0 Project Development Timetable

The current uncertainty over carbon legislation has paralyzed the permitting of coal-fired generation, which in turn will drive up natural gas development to meet load demand. Cline is fast-tracking the Raven Energy project to come on line in 2012 to meet the additional demand for natural gas. Cline has completed substantial feasibility and pre-FEED work. Raven is finalizing its technology licenses with best-in-class licensors and continuing its work on site development. Cline has fully funded the development budget for Front-End Engineering Design ("FEED"), and Raven expects to kick off its FEED process the first half of 2008. Raven anticipates beginning construction in 2009 shortly after completion of the FEED study and ancillary site work. Additional information on the Raven Energy development process and schedule can be made available to the Department of Energy on a confidential basis as needed.

The timeline below shows the summary project development timeline for both the Raven Energy Project and the Raven Deeps Project. Reservoir characterization, reservoir engineering, and leasehold activity that Cline is performing prior to and concurrent with the DOE RFI, FOA, and final project award process are included in the timeline below:

Figure 2 – Preliminary Project Development Timeline

[______________________________]

- Key dates of major CCS project components
    - DOE/Cline partnership finalized Qtr 1 2009
    - Drill test well(s) Qtr 4 2009
    - Permit Awarded Qtr 4 2010
    - Full scale drilling/infrastructure Qtr 3 2011
    - Injection/sequestration Qtr 4 2012

- MMV activity includes baseline, active, and post injection tasks, and will continue to some point in time past the stated 2020 project termination; CO_2 injection and active sequestration may continue past 2020

5.0 Identified Regulatory Issues

Below is a non-exhaustive table of regulatory and legal issues for which solutions must be found to further the Raven Deeps sequestration project:

Category:	Issue:	Comment:
Siting	Sequestration rights	Define which party or entity holds the right to sequester in saline aquifers (non-EOR)
	Condemnation of sequestration rights	Enable condemnation of sequestration rights for fair value to speed project development
	Unitization / Forced Pooling	Enable forced pooling of sequestration interests to ensure against potential liability of mineral trespass (with lateral migration)
	Interference with existing rights	Provide for dispute resolution / supremacy of CO2 injection and monitoring activities with pre-existing property rights
	Surface rights	Establish guidelines for use of surface during injection and monitoring / rights of entry
Permitting	Permit work definition	Provide adequate, cost-effective permitting requirements
	Bonding	Establish bonding guidelines for CO2 injector
	MMV timeframe definition	Establish definition of suitable timeframe for MMV
	Transfer/Sale	Establish permit review guideline if transfer prior to closure
	Closure	Establish procedure for termination of injection campaign
	Reclamation	Establish procedure for reclamation following closure
	Emergency venting	Establish procedure for emergency venting
Ownership & Liability	Ownership of CO2	State or Federal ownership post-closure
	Liability	Liability shield during injection phase, post-

Request for Information (RFI) on the Department of Energy's Plan to Restructure FutureGen

Response by SAIC

Program Management POC: Steve Gootee, Route 6, Box 28, Bloomfield, IN 47424; phone: 812-384-3587; fax: 812-384-3744; email: stephen.gootee@saic.com

Technical POC: Sharon Schnepf, 7990 Science Applications Drive, Vienna, VA 22182; phone: 703-676-0449; fax: 703-6776-1415; email: sharon.p.schnepf@saic.com

03 March 2008

This response includes data that shall not be disclosed outside the Government and shall not be duplicated, used, or disclosed-in whole or in part – for any purpose other than to evaluate this response. If however, a contract is awarded to this proposer as a result of, or in connection with, the submission of this data, the Government shall have the right to duplicate, use, or disclose the data to the extent provided in the resulting contract. This restriction does not limit the Government's right to use information contained in this data if it is obtained from another source without restriction.

Introduction

SAIC would like to commend the Department of Energy on its intent to restructure the FutureGen project to ensure it more closely reflects the needs of our Nation. Demonstration of advanced technology which utilizes coal, our most abundant natural resource, while also considering the mitigation of CO_2 is extremely important to not only our quality of life, but also to our future.

Heightened concerns regarding greenhouse gas emissions have promoted interest in the concept of carbon capture and storage. As a result, several states have imposed restrictions requiring all new coal-fired power plants be built with the capability to capture and store the resultant CO_2 emissions. However, requiring projects to just have the *capability* to capture and store CO_2 is far different from actually requiring the project to capture and store CO_2 ------and still be economically viable. Placing R&D emphasis on actual CO_2 mitigation in real, commercially viable IGCC plants and other large CO_2 emitting facilities based on clean coal technologies is sound policy and, if successful, will indeed accelerate public acceptance of coal as a viable solution to our domestic energy dilemma and could well reduce our dependence on foreign oil.

SAIC is very interested in participating in the revised FutureGen initiative regarding carbon capture and storage as described in the RFI. However, in light of the rapid expansion of clean coal technologies based on gasification, we would like to suggest DOE consider expanding the initiative to include:

- Clean coal technologies with large CO_2 output. In addition to IGCC based electric power, FutureGen should consider applications based on IGCC that include IGCC/liquid fuels, IGCC/hydrogen, and IGCC to industrial chemicals. CO_2 sequestration R&D in these areas will be applicable to a whole family of CO_2 generating technologies.
- Early stage innovative technology R&D targeted at reducing CO_2 per BTU of energy output to reduce the gross requirement for sequestration.

SAIC Activities in Indiana

Currently, SAIC is preparing a feasibility study for the Indiana State Government for a minimum-sized, commercially viable Coal Gasification/Liquid Fuels facility to be located at a site with good sequestration geology in southwestern Indiana. The facility, as designed, will exceed all existing environmental requirements. Rather than merely capturing a token percentage of CO_2 or providing the capability to capture and store CO_2, this facility will capture greater than 90% of the CO_2. Of particular relevance to this RFI, the reference design has the equipment "designed-in" to support multiple CO_2 off-takes for commercial use, R&D or demonstration projects. SAIC is working closely with the research community to include the capability for this facility to serve as a highly flexible clean-coal technology platform able to support research and development, as well as prototype and commercial demonstrations.

The facility will have an initial capacity to consume up to 3000 tons/day of Indiana coal and produce 5,000 to 6000 bbl/day of liquids for conversion into ultra clean diesel, kerosene and related fuels. Other commercially marketable byproducts include sulfur, mercury and slag.

Of significance is the net export of at least 25MW of continuous electric power, which would be utilized by the Crane Naval Warfare Center to make it electric energy independent in the event of an emergency. Based on the Defense Science Board (DSB) Task Force report regarding the troubling findings from the North American Reliability Corporation (NERC) on the state of grid reliability, this could represent a very feasible solution. Construction of a network of smaller facilities providing energy to military bases across the country would ensure energy independence should the national grid go down for any reason, including a terrorist attack.

Strong State of Indiana Support

The State of Indiana is aggressively pursuing a family of clean coal options as part of its energy strategy. It has supported a series of analyses assessing the suitability of Indiana as a home for a variety of coal gasification-based industries. Among many others, the state has funded an assessment of sequestration geologies and options. Not only is Indiana home to the Wabash River coal gasification facility, but the Indiana Department of Environmental Management recently approved the permits for a 650MW IGCC powerplant in Edwardsport, Indiana (explicitly designed as sequestration ready), and is considering other gasification proposals. With the potential of bringing multiple IGCC operations on-line, the State has engaged in discussions with key stakeholders about the potential for joint approaches to developing sequestration infrastructure. The State supports and encourages each of these teams to provide comments on the DOE RFI, and is committed to supporting responses to the RFI once issued – either individually or jointly. The State has provided funding for the SAIC Coal to Liquids feasibility study and is committed to facilitate development of a commercially viable coal to liquids plant that provides grid independence for the Navy's engineering center at Crane Indiana and that could be replicated nationally to reduce DoD energy dependence with reduced CO_2 emissions.

Innovative Technologies

Clean Coal Technologies, Inc (CCTI) is an US company working with China. With hopes of improving their pollution by reducing air emissions, China is building the first of what it hopes are many, new power plants using this new CCTI technology. Test cases of the reduction of airborne pollutants and contaminants are dramatic ---- up to 90%

What makes the CCTI patented technology so innovative is its emphasis on pre-cleaning and treatment of the coal prior to it being burned. Its benefits are far superior to traditional scrubbers because it removes volatile matter and other polluting agents from the raw coal without damaging the coal's basic structure, and costs 60-70% less This pre-treatment process makes the coal 10-50 percent more thermally efficient. Any percentage improvement in the thermal efficiency of coal would be significant, with an end result of less coal being burned and thus ensuring a longer life for the natural resource. Less coal being burned would result in reduced CO_2 and other pollutant missions being released into the atmosphere.

Most coal upgrading processes utilize heat and pressure to remove moisture and volatile matter from coal. However, these processes create an unstable coal product that is prone to moisture absorption, size degradation, and spontaneous combustion. CCTI's process uses a different approach -- a multi-stage heating process that gradually heats the coal under controlled residence times and atmospheric conditions to produce a stable product with an increased calorific content. The mix of gasses in each zone is proprietary to the process and ensures that volatile matters are removed from the coal in an inert environment that prevents the coal from self combusting to produce a clean coal fuel This is a unique and distinguishing aspect of this process over competitor processes

This technology could be integrated into the SAIC flexible clean-coal technology platform to support prototype and commercial demonstrations as part of this DOE initiative

Summary

SAIC would be very interested in participating in DOE's restructuring of the FutureGen Project --- and we could do that in a variety of ways. The SAIC Coal Gasification/Liquid Fuel facility could be utilized to develop and demonstrate CO_2 capture and sequestration. Additionally, the CCTI technology should be incorporated as part of the research and development being performed at the facility. Research performed at this facility could be critical in the revitalization of the coal industry in the US. The CCTI process is already being taken overseas so shouldn't our Nation perform research to determine if it is both a cost effective and energy efficient method to produce clean energy from coal? This research could revolutionize the coal industry and reduce our dependency on oil and foreign suppliers. Excellent opportunities exist for exporting clean domestic coal products --- with the United States becoming the leader in setting those standards worldwide

SCHLUMBERGER COMMENTS ON FUTUREGEN RESTRUCTURING

We support the DOE's decision to restructure FutureGen as it recognizes that IGCC and carbon capture have matured and can be commercially offered today. The greater concerns now are:

- Demonstrating that these plants can have storage integrated with the plant at large and commercial scale.
- Fostering a commercial industry that can find, validate, construct, operate and monitor effective storage sites.
- Progressing to a clear legal & regulatory framework for CCS.
- Addressing the public concern regarding the overall risks and safety of geologic storage.
- Identifying an inventory of sequestration options for power plant sites so that utilities can have firm options for geologic storage planning throughout the country.

Coal power generation may not progress in the United States without a solution to the CO_2 emission challenges. For this to occur, geologic storage of carbon must become a reality. Plant permitting has evolved from the loosely defined requirement to be "capture-ready", to a requirement for having a firm, quantified and technically feasible CO_2 capture and storage plan. Currently there is greater scrutiny being placed on these plans with pressure to ensure that technology is available to be applied. First wave demonstration projects must be sure to incorporate best available technology to properly assess the current state of the full CCS solution.

Some of the technical demands will be:

- Proving operational integration between power generation and sequestration. Both must be able to operate without increased shut down risk so that power generation demands are met with negligible impact. There will be a need for cross-optimization of plant output with injection management to ensure storage operations do not impact electric power generation.
- Demonstrating that large-scale sequestration can be applied in a variety of geologic settings. Methodologies need to be in place to handle site specific differences on a case by case basis. Multiple sites will be needed.

THE CHALLENGES

1 The lack of a clear regulatory framework for sequestration that addresses issues associated with the definition of property rights, liability, site

licensing and monitoring, ownership, compensation arrangements and other institutional and legal considerations.

2. An absence of regulatory protocols for sequestration projects including site selection, injection operation, and eventual transfer of custody to authority.
3. The lack of either a regulatory constraint or a market value for CO_2 set by either price, or avoided tax.

In order for commercial entities to step forward to participate, all of these barriers need to be addressed in the program structure.

Funding for the program needs to be adequate to fully defray the incremental capital costs of carbon-capture including the cost premium for technology that is compatible and ready for carbon capture plus the incremental costs of site selection, validation, design, construction & operations up and until such a time when a market value for storage is established.

RECOMMENDATIONS

We recommend a phased approach with respect to storage:

<u>Phase 1 - Storage Feasibility</u>: With participation from utilities having planned coal projects, preliminary regional studies are funded to identify the potential for storage within 50 miles of plant sites. This assessment may include low cost data acquisition such as re-entering old wells or the procurement of 2-D seismic. The expectation is only that certain site locations could be disqualified at this step and not that any specific site gets qualified. The estimated costs could be ~$1-$2MM per project. As part of its plans for FutureGen, funding for this phase would serve to develop the inventory of candidate projects that could move forward to the next phase.

<u>Phase 2 - Storage Detailed Study:</u> This will require acquisition of new data sets. It is in this phase that more costly techniques for site validation get employed. Evaluation wells get drilled with full sampling, logging & testing programs and proper 3-D seismic gets acquired, enabling detailed modeling & capacity estimation. Particular attention should be given to ensuring that best available technologies are identified and procured. In order to fully evaluate the overall state of sequestration technology, best available components must be applied. Caution must be taken that funding constraints don't force the acceptance of older generation technology as we have seen in lesser funded programs. ~$10-$20MM per project

Phase 3 - Validation: The final phase should be representative of an approved template for a site permitting process and require the presentation of a subsurface dynamic model with uncertainty ranges, data inputs, monitoring program & risk analysis. Qualifying sites having entered the permit process will be qualified then for funding for detailed design & construction & demonstration operation.~$2-$5MM per project

Timeline issues: The DOE should plan for a site selection, validation and permitting process that might take 3 years to complete. Access to services that might be in competition with the demands of the oil & gas industry may be a factor to consider. Additional funds might be needed to attract the necessary technical services and expertise required.

Recommended Changes to FutureGen Key Goals

Requirement	Comments	Recommended Changes
>1MM tons/yr CO_2	Can be site dependent.	The injection quantity should be of a volume requiring more than one injection well and the resulting plume should contact the caprock at a pressure above normal gradient but below caprock fracture pressure.
Saline aquifers	Largest potential CO_2 sink resource	None
Detect and monitor surface leakage	Surface leakage may occur well after a leak could be detected in the subsurface, if it occurs at all.	Detection, monitoring, and mitigation, if needed, of subsurface leakage. Detection, monitoring, and mitigation of surface leakage at artificial penetrations or faults.

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REPLY BY SEQENERGY, LLC TO DOE REQUEST FOR INFORMATION ON PLAN TO RESTRUCTURE FUTUREGEN

CAUTION: SECTIONS B AND APPENDIX B CONTAIN "BUSINESS CONFIDENTIAL" INFORMATION OF SEQEnergy, LLC (Marked by BOLD type) WHICH REQUESTS THAT DOE PROTECT TO THE EXTENT PERMITTED BY LAW.

A. Company Information

1. Company: SEQEnergy, LLC, a California Limited Liability Company
2. Point of Contact: Jon K. Myers, CEO/Managing Member

   Phone: 415.309.4750

   Address: 1770 Post Street, Box 314, San Francisco, CA 94114

   Email: jmyers8@comcast.net
3. Location of Project: Undetermined at this time but SEQEnergy is in preliminary discussions with a large U.S. utility to locate project at IGCC or other power plant in Eastern or Midwestern U.S. The SEQEnergy technology could be implemented at any of the four mentioned sites.

B. Description of Project: LONG TERM UNDERGROUND STORAGE FOR CARBON DIOXIDE

1. Company SEQEnergy, LLC ("SEQ", also formerly 'The Sequestration Company') is a privately-held engineering services and I.P. licensing business located in San Francisco, California.
2. **Project. REDACTED**
3. **Status of Project Development. REDACTED**
4. Technical Qualifications. The founders and principal officers are engineers deeply experienced in utility operations, oil and gas drilling, power plant construction and management, joined by co-founders and key advisors from business, engineering and university communities. A brief description of the backgrounds of the two principal engineers follows:

   Wade Dickinson, Chief Scientist

   - Bechtel Corporation, 25 years, Principal Engineer, Project Manager and Consultant

  - Athabasca Tar Sands, nuclear, coal, oil and gas production projects
  - Project Engineer, 40MW Peachbottom Nuclear Power Plant, Philadelphia Electric/Nuclear Power Group

- Development and commercialization of PetroJet® Multiple Lateral System and the 25,000 ft U.S. Navy Horizontal Drilling System (Project 230)
- RAND Corporation – Nuclear weapons reactors and satellite reconnaissance projects
- Carnegie-Mellon University (Aeronautical Engineering)
- U.S. Military Academy, West Point (B.S. Military Engineering)
- Oak Ridge School of Reactor Technology (First US Nuclear Engineering Graduate School Classified)

Wayne Dickinson, Chief Engineer

- Bechtel Corporation – Aluminum reduction, nuclear power plants, gas, steam, water projects
- 8 successful start-ups and 36 US patents (with Wade Dickinson)

Select Prior Achievements of Scientific and Engineering Team

  - Non-Drug Bovine/Porcine Growth Stimulation (UC Davis/Biopharmas)
  - High-temperature Gas-Cooled Nuclear Power (Bechtel)
  - Ultrasonic Weld Testing (NASA/U.S. Navy)
  - Ultrasonic Heart Monitoring (Stanford/UCSF/NASA)
  - WaterJet Drilling (U.S. Navy/Bechtel)

See Appendix A for more detailed bios of founders, management and advisors.

5. **Financial Qualifications** **REDACTED**
6. Estimated DOE Contribution. SEQEnergy believes that DOE funding would be appropriate for a portion of the Alpha stage and all of the Beta stage development expenses in the amount of approximately $30 million; however, SEQEnergy will continue to seek funds to cover part or all of such costs itself.
7. Timing. Our current development plan anticipates that the Alpha stage would be completed by end of 2009 and that the Beta stage would commence in early 2010. We see no reason why DOE funding could not be coordinated to assist with either or both of our Alpha and Beta development stages.

C. Comments on RFI.

SEQEnergy recommends that DOE modify its Plan to allow at least one utility to participate using SEQEnergy technology in its Beta development phase. This would require the following exemptions to the proposed plan for such project:

- Delete requirement that storage be in a saline formation. SEQ technology is geology-independent.
- Delete requirement for one million metric tons during the 1-year period. Although SEQEnergy's technology when fully developed will handle such volumes, we will still be in a Beta development phase during the life of the DOE grants and may not be able to accommodate such volumes in the Beta format. Nevertheless, it is in DOE's interest and interest of the industry for a meaningful test of SEQEnergy's technology to be accomplished with meaningful volumes ASAP.
- Delete the requirement for 90% capture from a 300MW power train. As above, we will be in Beta stage and may or may not be able to accommodate such volumes during that period but will be able to do so in full production mode.
- Because SEQEnergy's technology can be deployed at the site of existing coal-fired plants and such plants comprise almost all of the undesired CO_2 emissions, it may be useful for DOE to permit a demo at an existing non-IGCC plant if the sponsoring utility can effect capture similar to the IGCC plant.
- Decouple the power generation and sequestration aspects so that SEQEnergy or a contractor can assist and work with a utility to test this technology.

Appendix A: Resumes/Background information on key personnel

Wade Dickinson, Founder and Chief Scientist

Positions
- President, Petrolphysics, Inc. (PI)
- General Partner, Petrolphysics Partners, L.P. (PPLP)
- Founder, Managing Member and Chief Scientist, Solid Gas Technology (SGT, LLC)
- Founder, Managing Member and Chief Scientist, Sequestration Company (SEQ, LLC)

Education
- Carnegie-Mellon University, Pittsburgh, PA - Aeronautical Engineering, 1944-45
- U.S. Military Academy, West Point, NY - B.S., Military Engineering, 1945-49
- Oak Ridge School of Reactor Technology, Oak Ridge, TN –Graduate Nuclear Engineering, 1950-51

Professional
- American Physical Society
- Society of Petroleum Engineers

Typical Management and Technology Experience:

2005 – Present – Founder, Managing Member and Chief Scientist, SEQEnergy (SEQ), LLC.
Developing and applying proprietary technologies (patents pending) to sequester (store) Carbon Dioxide and compressed air in underground containments embodying flexible single and double wall fail-safe barriers, incorporating monitoring, leak detection, repair and auditing. Principal applications include coal fired power plants and solar power installations for long-term storage and peak shaving in both large and small scale markets.

2004 – Present- Founder, Managing Member and Chief Scientist, Solid Gas Technology (SGT),LLC.
New technologies (patents pending) to manufacture, store and distribute gaseous hydrocarbons (methane, propane,) as solid hydrates, for pipeline upgrading and peak shaving and for homes and retailers in the U.S.and Asia.

1975 - Present - President, Petrolphysics, Inc.
Developed and marketed, with the assistance of Bechtel Group and US Navy, the PetroJet® high pressure (15,000 psi) drilling system for oil wells, in situ heavy oil recovery and confidential US Government drilling projects.

1970 - 1995 - Research Associate Cardiology, Mt. Zion Hospital & Cancer Center, University of California, San Francisco, and Stanford Medical School, Palo Alto.
Development and application of proprietary ultrasonic cardiology (acoustic spectrometry). Consulting in cancer biotechnology and genomics.

1968 - 1990 - President, Agro-physics, Inc
Developed and marketed devices to stimulate growth and weight gain in cattle and hogs, in cooperation with the University of California, Davis

1960-1971 - President, W.W. Dickinson Corp.
Developed and marketed ultrasonic systems for nondestructive testing of pipe, NASA and U.S. Navy missiles and Navy submarines. Developed ultrasonic cardiology systems "acoustic spectrometry" for astronaut and medical application, with sponsorship by NASA Ames and in cooperation with Stanford Medical School.

1954-1988 – Senior Engineer through Principal Engineer and Consultant, Bechtel Group
Project Manager and Consultant for large commercial nuclear and fossil power plants, geothermal steam programs, Stanford Linear Accelerator, a large solar furnace, and coal-fired magneto hydrodynamic power sources. Confidential projects with US Government were often interleaved with commercial work

1957-1958 - Technical Advisor, Joint Committee on Atomic Energy, House of Representatives Armed Services and Senate Armed Services Committees
Managed studies and assisted the Chairman (Senator Clinton Anderson) in hearings on Aircraft and Naval Nuclear Propulsion, satellites, commercial nuclear power plants, ballistic missiles, reconnaissance and other satellite systems.

1952-1956 – Nuclear Physicist and Consultant, RAND Corporation, Santa Monica, CA
Responsible for analysis, preliminary design, and trade off studies of reconnaissance satellite power supplies.

1949-1954 – US Air Force Officer
Assigned to USAF Aircraft Nuclear Propulsion Project and various Confidential Intelligence Projects

Academic Experience:

1984-2004 - Lecturer, University of California, Berkeley
"Venture Design - The Start-up Company," College of Engineering, UC Berkeley
Teach and manage process of student created and managed Company Teams for entrepreneurial high technology ventures, each semester. 165 Student Company Projects were created. Several successful companies and approximately 700 technology company executives have resulted from the class.

Patents Issued and Pending (35+):

A large number of U.S. and Foreign Patents and Patent Applications in field of endocrinology, animal growth stimulation devices, seed vigor testing systems, ultrasonics, enhanced oil recovery equipment, and oil field drilling systems. Many publications and invited presentations have been made

Wayne Dickinson, Chief Engineer

Positions

Executive Vice President, Petrolphysics, Inc. (PI)
General Partner, Petrolphysics Partners, L.P. (PPLP)
Founder, Director and Chief Engineer, Solid Gas Technology (SGT, LLC)
Founder, Managing Member and Chief Engineer, SEQEnergy LLC

Education

Carnegie-Mellon University, Pittsburgh, PA – BS Mechanical Engineering, 1953-1957
UC Berkeley Extension – Computer programming, cryogenics, ultra high vacuum

Professional

American Society of Mechanical Engineers

Typical Management and Technology Experience:

2005 – Present – Founder, Managing Member and Chief Engineer, SEQEnergy. (SEQ), LLC.
Developing and applying proprietary technologies (patents pending) to sequester (store) Carbon Dioxide and compressed air in underground containments embodying flexible single and double wall fail-safe barriers, incorporating monitoring, leak detection, repair and auditing. Principal applications include coal fired power plants and solar power installations for long-term storage and peak shaving in both large and small scale markets.

2004 – Present- Founder, Managing Member and Chief Engineer, Solid Gas Technology (SGT),LLC.
New technologies (patents pending) to manufacture, store and distribute gaseous hydrocarbons (methane, propane,) as solid hydrates, for pipeline and process peak shaving as well as homes and retailers in U S and Asia.

1975 - Present – Executive Vice President, Petrolphysics, Inc.
Developed and marketing, with the assistance of Bechtel Group and US Navy, the PetroJet™ drilling system for oil wells, in situ heavy oil recovery and confidential US Government drilling projects

1970 - 1995 - Research Associate Cardiology, Mt. Zion Hospital & Cancer Center, University of California, San Francisco, and Stanford Medical School, Palo Alto.
Development and application of proprietary ultrasonic cardiology

1968 - 1990 – Executive Vice President, Agro-physics, Inc
Developed and marketed devices to stimulate non-chemical growth and weight gain in cattle and hogs, in cooperation with the University of California, Davis. Massive non-destructive testing of corn seeds for and with W.R. Grace.

1960-1971 – Executive Vice President, W.W. Dickinson Corp.
Developed and marketed ultrasonic systems for nondestructive testing of pipe, NASA missiles and US Navy submarines Developed ultrasonic cardiology systems "acoustic spectrometry" for astronaut and medical application, with technical and financial sponsorship by NASA Ames and in cooperation with Stanford Medical School, Palo Alto

1957, 1960-1964 – Engineer and Consultant, Bechtel Group
Design engineer for large U.S and Indian commercial nuclear BWR and GCR power plants, spent nuclear fuel processing plants

1957-1959 – US Army, Corp Engineers, 1st LT Executive Office
Field Maintenance company in Heidelberg, Germany

Academic Experience:

1984-2004 - Lecturer, University of California, Berkeley
"Venture Design - The Start-up Company," College of Engineering, UC Berkeley
Teach and manage process of student created and managed Company Teams for entrepreneurial high technology ventures, each semester. 165 Student Company Projects were created. Several successful companies and approximately 700 technology company executives have resulted from the class

Patents Issued and Pending (35+):

A large number of U.S and Foreign Patents and Patent Applications in field of endocrinology, animal growth stimulation devices, seed vigor testing systems, ultrasonics, enhanced oil recovery equipment, and oil field drilling system.

Jon Myers, CEO, Managing Member

- Ten years as founder, manager, director of successful technology-centric companies
- Prior 17 years in trading and arbitrage, sales and investment banking with major Wall Street firms including Goldman Sachs and Donaldson Lufkin Jenrette
- BA Williams College 1975, MBA Kellogg Graduate School of Business, Northwestern University 1980

Terry Brookshire, Chairman of the Board

- Founder and CEO of several successful financial and software firms
- Experienced entrepreneur and business leader
- Former Vice-Chairman, Pacific Stock Exchange

Key Advisors

Alexis T. Bell, Ph.D, Chair, Chemical Engineering, College of Chemistry, U.C. Berkeley
- Advisor in chemistry, catalysis and engineering of geological and CO2 systems

Porter Underwood, Formerly Senior Engineer, Halliburton
- Expert in geologic fracturing methods

John Mode, Formerly, Senior drilling engineer and field manager, Major Oil Companies
- Expert in drilling, design, costing and execution of complex, sub-surface facilities and piping systems

Shan Bhatttacharya, VP, Engineering, Pacific Gas and Electric (Retired)
- Adviser in energy markets and energy engineering

David Maul, Manager, Natural Gas Office, Energy Commission, State of California (Retired)
- Industry and regulatory advice and access

Appendix B: Additional Technology and Market Discussion

CONTAINMENT TECHNOLOGY REDACTED

HYDRAULIC REDACTED

CONTAINMENT REDACTED

COMPETITIVE ADVANTAGES OVER CONVENTIONAL SEQUESTRATION METHODS (IN NATURAL BRINE RESERVOIRS OR OIL WELLS/FIELDS) REDACTED

SET ★ Foundation

vision and service – where the future begins

FOIA exemption 4 is claimed for the excluded lines in the following redacted copy of SET Foundation's (SETF) 3/3/2008 original submission in response to your RFI. Competitive harm is highly likely in any FOIA release of SETF proprietary and/or business sensitive information. SETF is a small, recently incorporated entity that is positioning to license its intellectual property (IP) as a core business strategy. Also a utility patent that would formalize protection of the IP, has yet to be issued. Business/technology concepts have been exposed in the 3/3/2008 submission that may be taken by larger technology development entities. The blacked-out text in the redacted copy is SETF proprietary and/or business sensitive information that must be protected.

COMMENTS IN RESPONSE

TO

REQUEST FOR INFORMATION (RFI) ON

THE DEPARTMENT OF ENERGY'S

PLANT TO RESTRUCTURE FUTUREGEN

MARCH 3, 2008

NAME OF FIRM: **SET Foundation**
CONTACT: Irvin H. Davis, President
TELEPHONE: 301/277-7003
MAILING ADDR: P.O. Box 118
Hyattsville, MD 20781
EMAIL ADDR: idavis@setvision.org

LOCATION OF PROJECT: to be determined

NARRATIVE DESCRIPTION OF PROJECT

SETF approach to FutureGen reformulation

The SETF version for a reformulated FutureGen model would differ from the existing version in two aspects (see a fuller description in Appendix II-b):

1) [redacted]

2) [redacted]

The [redacted] Process also applies to retrofitted conventional power and early IGCC power systems [redacted]

Economic Benefits of the SETF technologies

Given the replacement of the carbon sequestration under the SETF system, funds anticipated for the creation of a nationwide grid of carbon sequestration facilities, be redirected to the retrofitting of the existing base of U.S. conventional pc-fired power plants to enable expanded carbon capture. Captured CO2 can be sold to [redacted]

Organizing for the project

At this point SETF is moving to organize a consortium to enable the rapid reduction of technology to practice. We will require R&D grants from DOE to achieve the work of the consortium. See the attached executive summary on the organization and it's technology.

SET ★ Foundation

vision and service – where the future begins

Executive Summary

This introduces the mission, initiatives and technology licensing potential of SET[1] Foundation. SETF is a nonprofit corporation for scientific research and new era economic development with a heavy technological twist. We believe the Foundation provides the missing ingredients needed for the vigorous development of subeconomic communities, while striving to serve America broadly. These ingredients consist of effective scientific, engineering, and technical cadres capable of creating robust technologies and derivative industrial ventures that generate significant employment and lasting socioeconomic fulfillment in our service community. We seek sponsors and grantgivers to achieve our purpose and initiatives.

SET Foundation and its mission

The SET Foundation, incorporated in August 2006 in New York, is a nonprofit corporation for scientific research and economic development. SETF is also registered to operate in Maryland. The Foundation has a seven-person board of directors and other capable team members who together, provide an ideal skills mix in the sciences, engineering, industrial operations, grantwriting, and insightful business development. The board works toward the advancement of the Foundation's mission (See Appendix I for SETF director profiles)

Our mission is to conduct socioeconomic research, develop innovative technologies and build viable business paradigms towards sustainable development in subeconomic communities. SETF's mission is exemplified by a program initiative for regional development in central Alabama. As discussed more fully later, this initiative seeks to provide clean energy, new industrial capacity, and badly needed jobs, through our association with sister for-profit operators who license SETF technology.

The Foundation embodies a new approach to economic development. Our vision is that innovative, robust technologies can be tasked with enriching subeconomic communities, just as they have historically served as primemovers in the accrual of wealth in major metropolitan centers. We believe that significant levels of productive resources can be steered to such communities to achieve their lasting economic fulfillment.

Why is SETF unique and a portal for greater service to the nation?

Much of our approach is modeled on best practices that underpinned America's industrial evolution – the synergy of technological innovation and vertically integrated industrial superstructures from mining to finished product distribution. Through these proven practices, firms like Standard Oil, US Steel, and Alcoa joined the ranks of the largest corporations in the world, more than a century ago, to achieve lasting prominence in their respective sectors and massive profits. History has shown that such a large-scale synergistic approach can generate strong profitability and thousands of blue-collar jobs – the very outcomes so desperately sought in the communities targeted for assistance by SETF.

The simple claim of the Foundation is that – today, we've demonstrated the capacity to organize and control robust proprietary technologies and large-scale derivative ventures that generate massive employment for the benefit of SETF's service community and the nation as a whole. This is possible due to our unique team of inventors and scientific innovators, insightful business developers, and proven industrial managers. To achieve SETF's goal, we will partner with firms in energy technology, power generation and mining/metalmaking, together with academic institutions and the DOE's National Labs.

Technology and initiatives

[redacted]

[1] *SET: The acronym stands for "Scientific, Engineering, and Technical." SETF: SET Foundation*

[redacted]

SET Foundation

Irvin Davis, President

Appendix I – SET Foundation Directors

[redacted]

[redacted]

More detailed profiles of directors and staff are available on request.

SET ★ Foundation

Innovation for socioeconomic change

Appendix II-a

[redacted]

* SETF Proprietary: all rights retained; use/disclosure of material for other purposes is forbidden – contact idavis@setvision.org.

SET ★ Foundation

*IGCC Carbon Oxides Management**

[redacted]

[redacted]

* SETF Proprietary: all rights retained; use/disclosure of material for other purposes is forbidden – contact idavis@setvision.org

Dear Mr. Miles:

In response to the DOE's request for public comments regarding the "Request for Information" ("RFI") ON THE DEPARTMENT OF ENERGY'S PLAN TO RESTRUCTURE FUTUREGEN, Shell appreciates the opportunity to share our thoughts on improvements that we believe will demonstrate and further develop clean utilization of our national coal reserves and large-scale Carbon Capture and Storage ("CCS").

DOE Plan Should Expand to Coal Gasification Applications Beyond IGCC

We believe that the DOE's ultimate purpose in a restructured FutureGen program is to fund multiple projects that demonstrate the cleanest coal utilization while also capturing and storing the carbon dioxide at commercial scale. Shell agrees that this is needed given the national desire to improve our domestic energy security by cleanly using our large domestic coal reserves while also capturing and storing the carbon dioxide. However, given that the main driver is to demonstrate clean coal usage with large-scale CCS projects, the DOE Plan should focus on Coal/Petcoke Gasification projects (the cleanest coal utilization technology and the most efficient for CO2 capture), but not restrict the support only to IGCC projects.

From our Houston offices, Shell US Clean Coal Energy, Inc. is actively developing (or providing technology to) a broad range of projects in the United States where "Syngas" (Carbon Monoxide plus Hydrogen) is produced from coal/petcoke using Shell's Coal/Petcoke gasification technology. These projects include applications such as IGCC's, Coal to Liquids (CTL) facilities, Synthetic Natural Gas (SNG) plants, and hydrogen/chemical plants. Each of these projects will produce several million tons per year of CO2 and plan to capture and store their produced CO2. These projects will enhance US Energy Security and also help the US seize technology leadership, but these same projects may not happen without CCS assistance.

CCS Projects Will Require More than Economic Incentive to Proceed

Shell believes the capabilities possessed by the petroleum industry (geologic assessment, drilling and injection) apply directly to implementing a CCS project. Thus we are confident that large scale CCS will happen and be successful; however, we also recognize that the US currently lacks a clear regulatory program to ensure CCS is done to high standards, that geologic pore space ownership is clear, and that long-term liabilities are clear as well. We suggest that the DOE Plan address these issues if possible alongside the economic support.

Closing

We hope to participate when the DOE issues a competitive Funding Opportunity Announcement (FOA) in next few months, and I hope that the FOA incorporates the thoughts outlined in this letter. Thank you for the opportunity to comment on this extremely important and valuable program to utilize our large domestic coal reserves as cleanly as possible and to demonstrate large scale CCS.

Please do not hesitate to contact me at any time if would like to discuss further this matter.

Sincerely,

Milton Hernandez

VP Clean Coal Energy, Americas

Shell US Gas & Power

Sierra Pacific Resources
Comments in Response to
DOE's Request for Information on Plan to Restructure FutureGen

Sierra Pacific Resources, parent company of Nevada Power Company and Sierra Pacific Power Company, submits the following comments in response to DOE's invitation for expressions of interest and comments on its proposed restructuring of the FutureGen program (the "RFI"). Sierra Pacific has a strong interest in participating in FutureGen and is well advanced in its planning for the Ely Energy Center, an ultra-supercritical coal-fired power plant that we believe could offer some unique benefits to the reconfigured FutureGen program. Our comments are divided into two parts: Part I provides the project information that DOE specifically requests in the RFI. Part II comments on the issues raised in the RFI, including most particularly the question whether the revised FutureGen program should allow for advanced coal technology systems other than IGCC at locations other than the finalist sites for the prior FutureGen program

Part I. Ely Energy Center - Project Description

Point of Contact:

David Sims, Director, Project Development
(702) 367-5860 [office]
(702) 334-5860 [cell]
Sierra Pacific Resources
6226 West Sahara Avenue
Las Vegas, Nevada, 891 5 1
dsims@.~ievp.com

Location of Project:

EastICentral Nevada
White Pine County, Nevada
Approximately 20 miles north of Ely, Nevada (250 miles north of Las Vegas)

Narrative Description of Project:

The Ely Energy Center is a 2500-megawatt coal-fueled power plant that will be built in two phases. The first phase (1500 MW), which itself will be constructed in two 750 MW phases, is being developed as an Ultra-Supercritical Pulverized Coal (USCPC) project. The second phase is intended to utilize the Integrated Gasification Combined Cycle (IGCC) technology with Carbon Capture and Storage (CCS) once that technology has been demonstrated at elevation and with sub-bituminous coal. The facility is designed to be the cleanest coal plant in the West in terms of its emissions control technology. Additionally, it is being designed to consume half the normal requirement of water by utilizing a hybrid cooling technology. The facility will operate at extremely high efficiencies, allowing the Companies to retire 300 megawatts of 50-year-old coal facilities at the Reid Gardner Generating Station.

The project is being developed by Sierra Pacific Resources, which is headquartered in Nevada and is an investor-owned corporation with operating subsidiaries engaged in the utility business. The company's stock is traded on the New York Stock Exchange under the ticker symbol SRP. The company's chief operating subsidiaries are Nevada Power Company and Sierra Pacific Power Company, which together serve more than one million customers. The operate as regulated utilities under the jurisdiction of the Public Utilities Commission of Nevada.

The Ely Energy Center has been in the development stage since 2006 and is awaiting a final air permit by the Nevada Division of Environmental Protection and an Environmental Impact Statement (EIS) from the U.S. Department of Interior's Bureau of Land Management.

The project development has been approved by the Public Utilities Commission of Nevada, and it has received support in writing from the White Pine County Commission, the Ely City Council, the McGill Town Council, and the majority of local businesses, taxing authorities, the local news media and community members. Among the reasons for this project's widespread support is that it will enable Nevada Power to decommission three older coal-fueled units in Nevada, improve the state's system reliability by directly connecting the northern Nevada grid with the Southern grid for the first time, open the pathway for transmission-locked renewable energy, and help Nevada be more energy independent and improve its energy diversity by relying less on natural gas.

The company has extensive experience with pulverized coal plants at its Reid Gardner Generating Station and its North Valmy Generating Station. It also has experience with IGCC technology, as it helped pioneer that technology at its Piñon Pine Power Project near Reno, Nevada.

Project Timetable:

The Ely Energy Center has completed key regulatory, community support, water resources and other milestones. Construction is scheduled to begin in 2010 or 201 1, depending on completion of the EIS process and issuance of a record of decision. Under conservative planning assumptions, Ely is scheduled to commence commercial operations in 2015, DOE'S target date for CCS projects.

Requested DOE Contribution to CCS:

Sierra Pacific does not yet have an estimate of the cost of CCS for Ely, and thus cannot specify a requested DOE contribution at this time. The company has begun detailed analysis of the geologic formations in Nevada that could best support CCS in a saline aquifer as called for in the RFI (as well as the other CCS options for Ely, such as enhanced oil recovery). Thus, it will be able to provide cost estimates for CCS and to identify a requested DOE contribution in response to the Funding Opportunity Announcement (FOA) that DOE expects to issue in the next several months.

Technological, Financial or Legal Issues or Barriers:

Sierra Pacific does not believe that Ely presents any unique technological, financial or legal issues. USCPC technology commercially proven, and the Company, as noted above, the company has extensive experience operating pulverized coal plants. The carbon capture aspect of the project is, of course, the known challenge, but there has been substantial research and development of carbon capture as applied to pulverized coal technology, and the technology risk associated with carbon capture and storage is at the heart of FutureGen. The distinct programmatic advantage Ely offers DOE is that applying CCS to a USCPC plant offers the greatest promise for accelerating the development of a retrofit technology for CCS that can be applied to the predominant coal burning power plant technology in use in the United States and the world. For decades to come, pulverized coal technology will dominate power generation. Expanding the scope of FutureGen to allow proof of CCS on this technology can greatly increase the benefit of this demonstration program.

Ely presents no unusual financial or regulatory barriers, but rather offers distinct advantages that reduce its risk profile. It is a facility that will be in a regulated rate base, and the Public Utilities Commission of Nevada has already approved development costs for Ely. It will be subject to normal regulatory oversight during the various project stages. The Nevada Department of Environmental Protection, the relevant air permitting authority, is presently considering Sierra Pacific's air permit application, but it has publicly stated that it believes the plant's emissions profile is probably the best in the Nation.

Other Project Benefits:

The Ely project offers two important additional benefits. First, it will be accompanied by the addition of transmission capability that will also enable up to 500 MW of renewable energy that currently has no transmission pathway to be delivered to customers in southern and northern Nevada. Second, in addition to hosting the CCS demonstration, the Companies have actively studied the integration of a solar thermal system into various points within the USCPC plant steam cycle. In such an arrangement, a solar thermal energy system would convert water to millions of Btu's of hot water and/or steam, and inject it at one or more points within the plant's cycle, reducing the amount of energy required to be generated from the burning of coal. Studies are currently underway to refine the amount of solar thermal energy that could be generated and how it could best be integrated into the boilers. This aspect of the project, for which the con~paniesw ould not be seeking DOE funding, could greatly offset the energy penalty typically thought to accompany carbon capture in USCPC plants. The Companies would be pleased to explore incorporating this novel use of renewable energy into the project, and we are prepared to submit a formal proposal to do so as part of our application responding to the FOA.

Part 11. Comments on DOE's Revised Approach to FutureGen

Sierra Pacific Resources applauds DOE's attempts to move forward and demonstrate the ability to capture and store carbon from coal-based power plants. We are strongly interested in participating with the Department and, if the terms of the FOA permit, Sierra Pacific will respond to the Department's FOA for a facility to demonstrate CCS at its proposed Ely Energy Center. The plant would provide a working demonstration of CCS facilities on ultra-supercritical boilers fueled with Powder River Basin coal. We are pleased to offer the following comments on the RFI, comments focused on a request that DOE expand its focus in the FOA to allow multiple coal-fired technologies from throughout the country, and most particularly in the West, where there is a great need to establish the viability of CCS.

Technology Choice:

DOE proposes to limit FutureGen CCS projects to power plants based on IGCC technology. Sierra Pacific respectfully suggests that this multi-award program should make room for one or more non-IGCC technologies. As noted above, pulverized coal (PC) technology is the predominant coal burning technology in use today Demonstrating CCS on a PC technology will provide the maximum programmatic benefit in that it will greatly accelerate the availability of CCS to the plants that are already in operation and likely to continue to operate for decades to come. Given the pace of development of PC plants that is ongoing around the world today, this is a highly significant benefit.

Moreover, as emphasized in MIT's recently published study "The Future of Coal," it is unwise to let a single technology be the focus of our carbon capture and sequestration research efforts at this early stage:

> It is premature to select one coal conversion technology as the preferred route for cost-effective electricity generation combined with CCS. With present technologies and higher quality coals, the cost of electricity generated with CCS is cheaper for IGCC than for air or oxygen driven SCPC. For sub-bituminous coals and lignite, the cost difference is significantly less and could even be reversed by future technical advances. Since commercialization of clean coal technology requires advances in R&D as well as technology demonstration, other conversion/combustion technologies should not be ruled out today and deserve R&D support at the process development unit (PDU) scale *(MIT Studv on The Future of Coal, p 98)*

Although some have suggested that IGCC offers the easiest implementation of CCS for a grassroots or "greenfield" plant, there are other technologies that should be included in the program to ensure that the viability of CCS is demonstrated with a range of fuels. Today, for example, there is no demonstrated commercial experience with IGCC using sub-bituminous Powder River Basin (PRB) coal, even though it is one of the nation's most widely used sources of energy, and, because of its low sulfur content, of significant benefit in the control of emissions of S02lS03. Restricting the FOA to IGCC units only would significantly diminish the likelihood of any demonstration of CCS projects using PRB coal.

In focusing its attention on IGCC, DOE appears to be betting that IGCC-CCS is the most costeffective
approach to achieving DOE'S stated goals. However, as EPRI has explained, from a cost standpoint, IGCC offers no clear and consistent cost advantage:

> Some studies show an advantage for IGCC with CCS with bituminous coal. With lignite coal SCPC with CCS is generally preferred. With sub-bituminous coals, SCPC with CCS and IGCC with CCS appear to show similar costs. *(Testimony of Bryan Hannegan, Vice President-Environment, Electric Power Research Institute, before the Science, Technology and Innovation Subcommittee of the Committee on Commerce, Science, and Transportation, November 7, 2007.)*

Thus, DOE should take care in this important program to avoid the proverbial "eggs in one basket" approach. There are several coal-based technologies in addition to IGCC that provide opportunities for the integration and testing of CCS. These include super-critical pulverized coal (SCPC), ultra supercritical pulverized coal (USCPC), and oxy-fueled coal plants. Each has its unique attributes and potential advantages for CCS, and they should all be eligible for consideration in the restructured FutureGen program to ensure that a full range of alternative technologies is available to the nation with CCS.

Emissions Targets:

The emissions targets DOE identifies in the RFI as its objectives for participating projects essentially reinforce the preference for IGCC technology since they are emissions standards that only IGCC can meet. Sierra Pacific's USCPC Ely project comes very close to meeting those standards. It is designed to achieve the following emissions levels:

97% sulfur removal
.06 lb./million Btu NOx emissions
99% removal of particulate matter
>90% mercury removal

Very small deviations of this type from DOE'S identified emissions objectives should not preclude a project's participation in FutureGen.

Geographic Diversity:

DOE encourages potential program applicants to focus their proposed demonstration facilities at the four original FutureGen sites:

> The Department recognizes the tremendous effort expended by the four sites - two in Illinois and two in Texas - evaluated in the Department's Environmental Impact Statement (EIS). . . . The site announced by the FutureGen Industrial Alliance in December 2007, Mattoon, IL, as well as the other three sites evaluated in the EIS may be eligible to host a commercial-scale IGCC plant with CCS technology. DOE encourages appl~canttso include these four sites in their consideration for this restructured FutureGen approach since the site analysis and characterization data at those four sites may be applicable to future environmental analyses under this restructured approach. (*RFI* at 5.)

This would effectively limit the demonstration value of the program to two geographic areas, Texas and Illinois, and would thus preclude the program from demonstrating CCS is a variety of geographic locations and environments. Although Sierra Pacific recognizes that significant environmental effort was expended in the Department's FutureGen EIS, other sites may offer substantial other benefits and may even have similar environmental analysis underway in connection with plans for a coal plant using a non-IGCC technology, as is the case with the Ely project. Such projects at alternative locations should not be barred from even competing to participate in the restructured FutureGen program.

It is noteworthy that the West is home to many of the fastest growing states and populations, and is thus likely to face the fastest growing demand for electricity. FutureGen's benefit will be greatly increased if it provides demonstrations in areas like the West that are going to require significant new generation capacity. Moreover, broadening the geographic horizon of the program will enhance the demonstration value of the program by allowing it to test CCS with a wider range of coal types. Indeed, IGCC coal plants, using bituminous coal (the predominant coal in the eastern US.) and operated at or near sea level, have already been built and are being operated in the eastern US., in Florida and Indiana. However, CCS has not been demonstrated with sub-bituminous coal, such as Powder River Basin coal, the coal most abundant in the West.

Finally, broadening the geographic horizon of the program will offer the opportunity to demonstrate CCS at higher elevations, provided the IGCC-only focus is also lifted. As DOE is well aware, IGCC plants face a decline in output of at higher elevations because of the much lower air density and decreased gas turbine output. If the FOA limits its demonstration of carbon capture to Texas and Illinois IGCC units as the only potential hosts for the research, it will in effect limit the benefit of the demonstration to the eastern United States. There would seem to be no legitimate programmatic justification for such a narrowly focused program, when the need for CCS exists throughout the country.

NAME, POINT OF CONTACT, TELEPHONE NUMBER, MAILING ADDRESS, E-MAIL ADDRESS

Skyonic Corporation
Stacy MacDiarmid, Director of Communications
Tel: 512 436.9276
3600 Bee Cave Road
Suite 200
Austin, TX 78746
stacy@skyonic.com

LOCATION OF PROJECT

The proposed project site is the 2 unit, 1 2 gigawatt Luminant coal-fired power plant in Fairfield, Texas, Big Brown Steam Electric Station. For fuel, Big Brown blends Texas Lignite coal from its own mine-mouth operation with Western subbituminous coal. Big Brown units are equipped with low NOx burners, overfire air, electrostatic precipitators and pulse-jet fabric filter baghouses. In addition, Luminant will be installing selective non-catalytic reduction technology on these units. Luminant, a subsidiary of Energy Future Holdings Corp. (EFH), is a competitive power generation business, including mining, wholesale marketing and trading, construction and development operations, with more than 18,300 megawatts (MW) of generation in Texas, including 2,300 MW of nuclear and 5,800 MW of coal-fueled generation capacity Possible alternate locations are being discussed. This is a retrofit option to existing coal power plants.

NARRATIVE DESCRIPTION OF PROJECT THAT INCLUDES THE STATUS OF PROJECT DEVELOPMENT AND THE TECHNICAL AND FINANCIAL QUALIFICATIONS OF THE PROJECT TEAM TO CONDUCT THE PROJECT

The project that Skyonic Corporation proposes is a commercial-scale implementation of the SkyMine™ process at Luminant Power's Big Brown Steam Electric Station in Fairfield, Texas The SkyMine™ process is a post-combustion, multi-pollutant-removal technology SkyMine™ plants capture the emissions from the stack and send them through the SkyMine™ process, where mercury and heavy metals are removed, acid-gases are removed, and carbon dioxide emissions are captured and mineralized for safe, permanent, solid sequestration of carbon Since the sequestration product is a solid, this process differs materially from sequestration techniques that require the gaseous injection technology currently considered in FutureGen and there are no injection and subsequent leakage considerations. While it can be employed with IGCC, it does not require it. The first deployment of this technology is targeted at reducing CO_2 emissions at existing coal-fired plants.

Skyonic has developed the SkyMine™ process to mineralize gaseous CO_2 after combustion, changing it into solid, stable, non-toxic $NaHCO_3$ and Na_2CO_3, which can then be returned to the ground as inert filler In the current application, flue gas from coal power generation is processed through several steps to generate primarily $NaHCO_3$. In addition, heavy metals present in coal, such as mercury, and acid gases, such as SOx and NOx, are removed and converted into a solid, concentrated, easily-managed form. Testing with two different coal sources, Texas lignite and PRB coal show no difference in process performance in removing metals, acid gases and carbon dioxide. As part of the process, on-site electrolysis generates hydrogen and chlorine, both necessary chemicals that can be sold to market, and NaOH, which is consumed in the mineralization process. All of this can be accomplished at significantly lower energy penalty than other, existing technologies.

Using a low energy electrochemical process, SkyMine™ produces sodium hydroxide (NaOH) from a salt solution, which is reacted with the CO_2 in the flue gas to produce primarily sodium bicarbonate (baking soda). The benefit of the lower energy process can be seen in the table below compared to a typical gaseous sequestration process. The results in the table have been verified with Southwest Research Institute.

	Units	Base Case Power Plant	Typical MEA Plant (96% CO2 Emissions Avoided)	SkyMine™ Process (96% CO2 Emissions Avoided)
Coal Input Heat (HHV)	kW	1239361	1239361	1239361
Existing Steam Turbine Generator Output(+)	kW	463478	269341	463478
CO2 Turbine Output(+)	kW	0	62081	0
Potential Energy from Captured Hydrogen(+)	kW	0	0	340346
Total Plant output	kW	463478	331422	803824
Total Auxiliary Power (-)	kW	29700	70665	501450
Total Transport/Compression Power(-)	kW	0	25143	5469
Net Plant Output	kW	433778	235614	296905
% Decrease in Net Plant Output	*%*	***0***	***46***	***32***
Plant Thermal Efficiency (Coal Input/Net Output)	*%*	***35***	***19***	***24***

Since the CO_2 is sequestered as a solid, there is no issue with compression, transport and storage, as with a gaseous system. Standard transport systems such as truck or rail can be used to transport the solid sodium bicarbonate. Additionally, since no special geologic formation is required for storage and the material is non-toxic, the process can be employed almost anywhere. Therefore, the transport and storage are not an integral part of the power generation process and could reasonably be decoupled from it and performed by a separate entity.

Skyonic Corporation was founded in 2005, and has spent three years completing lab research at Southwest Research Institute in San Antonio, TX, and field research, trial, and demonstration at LCRA's Fayette coal plant, and Luminant's (formerly TXU's) Big Brown Steam Electric Station in Fairfield, TX. There is a currently operating pilot plant (tens of tons) on-site at the Big Brown Steam Electric Station. Skyonic is now modeling and specifying a commercial scale plant. The next step is to complete a site-specific design for the largest commercial CO_2-capture system in the world.

Currently, Skyonic is funded with private money. We envision a joint-venture for the first plant, in which a consortium of utilities, chemical partners, contractors, and large corporations will contribute funds, in return receiving carbon credits and public relations benefits. Profits from the chemical operations would ultimately pay for the operation of the carbon capture plant.

The project director and inventor of the SkyMine™ process is Joe David Jones; he earned his BS in Chemical Engineering from the University of Texas at Austin and spent the first 25 years of his career in the semiconductor manufacturing industry. Starting with chemical, electrical, and electro-chemical process engineering, he went on to manage Process & Product teams for Ross, Sun Microsystems and Fujitsu. Achieving low-power operation in semiconductor devices lead directly to Jones's development of a low-energy method of sequestering CO_2, as analogous power-reductions apply to electro-chemical cell operation. Mr. Jones is the author and holder of a high-speed testing patent from the United States Patent Office, and has also submitted two patent applications (nos. 20060185985 and 60/973,948) called "Removing Carbon Dioxide from Waste Streams through Co-Generation of Carbonate and/or Bicarbonate Materials" to the U.S. Patent Office.

The lead engineer on the project is Skyonic's Vice-President of Field Operations, David St Angelo. Mr. St. Angelo joined Skyonic in May of 2005. He earned a Bachelors in Chemical Engineering from the University of Massachusetts and a Masters in Electrical Engineering from Northeastern University. Prior to joining Skyonic, Mr. St. Angelo worked in the field of rechargeable lithium batteries at Valence Technology and in technology research at Mobil Solar Energy. Mr. St. Angelo built both of the demonstration plants currently on the ground at Big Brown, and continues to work on optimizations of the SkyMine™ process

DISCUSSION OF THE COMPANY'S ABILITY TO MEET OR EXCEED THE TIME FRAME SET FORTH IN THE ABOVE SCHEDULE

Skyonic has already begun the generalized design for this plant, and has begun assembling the contractors needed for the project. We are on track to have a generalized design completed by the end of 2008, and could begin a site-specific design, to be completed, including contracts to sell the by-products, by the end of 2009. Since this is designed to be a retrofit on an existing coal plant, a phased approach is planned. The initial plant would be designed to capture ~40% of the CO_2 from a 50 MW equivalent stream. We anticipate the construction of this phase to take approximately 18 months, with the plant on-line 2011. The process design is such that implementation could be done incrementally and additional capacity could be added to reach 300 MW by 2014. While the process could capture 90%, this project would not be designed in such a manner since it would be retrofit to an existing plant that has a lower efficiency than newer technologies. In addition, the process is of a modular design and planned as a retrofit to existing plants. The chemical portion of the plant could be operated during the hours when demand and electricity cost are lower while the absorption portion could run 24 hours per day.

ESTIMATED AMOUNT OF DOE CONTRIBUTION (IN PERCENTAGE AND/OR DOLLARS) THAT WOULD BE REQUIRED FOR THE COMPANY TO PURSUE THE PROJECT WITH IGCC-CCS TECHNOLOGY

Since this project is a retrofit for an existing coal power plant, there are no costs associated with an IGCC plant. All incurred costs would be for the CCS project. We anticipate a DOE contribution of 50% of the initial capital.

ANY TECHNOLOGICAL, FINANCIAL, OR LEGAL ISSUES OR BARRIERS THAT DOE SHOULD BE MADE AWARE OF THAT LIMIT THE EFFECTIVENESS OR FEASIBILITY OF DOE'S RESTRUCTURED APPROACH TO FUTUREGEN

The FutureGen project, even in the restructured form, assumes that all CO_2 sequestration is in gaseous form and that it can only be accomplished on new plant technologies. Such a narrow definition of sequestration will both limit the creativity and exclude from consideration viable technologies that can address new plants' as well as the existing coal fleet's CO_2 emissions

OTHER INFORMATION OR CONCERNS THAT WOULD ASSIST DOE IN IMPLEMENTING THE REVISED FUTUREGEN

A fast track program for technologies that are deployable and retrofittable would accelerate the implementation of FutureGen.

DOE seeks comments on whether the revised FutureGen approach should allow for advanced coal technology systems, other than IGCC, that would also meet the performance requirements stated above. If an interested party believes such an alternative technology is warranted, such party should provide the same information requested in the bullets above

The flexibility of the SkyMine™ process also allows it to work with the more advanced coal technologies as an integral part of the design. In fact, in more efficient plants, the technology is even more attractive as the amount of power consumed is related to the amount of CO_2 captured. If the plant produces a lower amount of CO_2 per megaWatt, the percentage of the plant power needed by SkyMine™ is accordingly lower.

DOE also seeks comments on whether the carbon transport and storage of CO_2 may reasonably be decoupled from the power generation aspects of the project and performed by separate entities.

As noted above, since the CO_2 is sequestered as a solid, there is no issue with compression, transport and storage, as with a gaseous system. Standard transport systems such as truck or rail can be used to transport the solid sodium bicarbonate. Additionally, since no special geologic formation is required for storage and the material is non-toxic, the process can be employed almost anywhere. Therefore, the transport and storage are not an integral part of the power generation process and could reasonably be decoupled from it and performed by a separate entity.

Southern Company Comments on Restructured FutureGen Program Request for Information (RFI) from DOE dated January 30, 2008

Background

Southern Company was instrumental in the formation of the FutureGen Industrial Alliance and has been an active participant since its inauguration in August, 2005. Southern Company personnel served as the initial Chairman of the Board of Directors for the Alliance and as Chair of the Technical Committee during the first critical year of FutureGen operations. As such, Southern Company has some significant insights to offer to DOE regarding the restructured FutureGen program.

Southern Company supports the FutureGen project. The company joined the FutureGen Industrial Alliance due to a need to develop, demonstrate and understand integrated gasification combined cycle technology that includes significant carbon capture and sequestration. The FutureGen project offered the opportunity to demonstrate the significant technology advances (e.g. hydrogen turbines) required to make IGCC with CCS operate reliably for electric utility applications.

Southern Company lauds DOE's goals to accelerate demonstration of advanced carbon capture and sequestration (CCS) technology. The U.S. and global energy industries need commercially demonstrated, cost-effective CCS technology that can be counted on for reliable electric power generation while minimizing air and water emissions at the lowest possible electricity cost.

However, the draft solicitation criteria outlined in the RFI raise concerns that the restructured program will not meet DOE's goals. We have specific concerns about the following proposed criteria:

> "Demonstrate approximately 90 percent CO_2 capture and storage on one nominal 300 MW train with annual requirements of one million metric tons in a saline aquifer and
>
> - > 99 percent sulfur removal
> - <0.05 lb/Mbtu NOx emissions
> - <0.005 lb/Mbtu particulate matter emissions
> - >90 percent mercury removal"
>
> And
>
> "at least one million metric tons of CO_2 must be stored in a saline storage formation, CO_2 in excess of one million metric of CO_2 per year may be used for enhanced oil recovery.....or other uses that result in permanent storage of CO_2."

Specific Southern Company comments are:

1. DOE's goal of demonstrating IGCC with CCS in commercial plants must balance cost and risk.

The original intent of FutureGen was to drive CCS technology forward. Due to the high cost, technical risk and research nature of the large-scale FutureGen effort as originally conceived it was appropriate for the federal government through DOE to take most of this risk in a first-of-a-kind (FOAK) project. Moreover, because of the costs and risks were large, no single company was able to bear the remaining technical risk individually. Thus, commercial risk was appropriately spread over several private companies.

Much of the technical and cost risks in the original FutureGen project stemmed from the requirements for 90% CO_2 removal and long-term CO_2 sequestration requirements Establishing these same criteria as a condition for DOE cost share to support CCS in a restructured FutureGen program as part of commercial power projects transfers FOAK cost and risk to the private sector

The proposed criteria to require 90% total CO_2 capture from at least 300 MW are overly stringent for a FOAK application of CCS in a commercial IGCC plant. CO_2 capture at this level will result in a syngas containing large amounts of hydrogen. To-date, no utility-scale F- or G-class gas turbine has been operated commercially or even demonstrated in short-term trials to enable utilization of a high-hydrogen fuel, despite some OEM's claims.[1]

In addition, to achieve 90% total CO_2 capture in a single train will require at least 2 if not 3 stages of water gas shift (WGS) reactors which must be integrated into the thermal system of a commercial power plant. To-date, no operating power plant has been designed or operated with such a dramatic modification to the steam/thermal system.

The original FutureGen project was conceived to enable public-private partnership in sharing of the technological risk for integrated operation of CCS with IGCC. The restructured program – if it maintains 90% total CO_2 capture as a criterion for DOE cost share participation, places an inordinate amount of technical risk on the private sector and may result in no bidders for the restructured program.

A large amount of captured anthropogenic CO_2 is necessary to adequately demonstrate sequestration. However, it seems unnecessary to carry forward the original FutureGen specification of one million metric TPY to the restructured program. Depending on site and gasifier specific issues 15 to 25 % of the carbon delivered to the gasifier in the coal is present in the syngas as CO_2 as it exits the gasifier. If the bulk of this "native" CO_2 is removed from the syngas from a 2x1 IGCC plant then 500,000 to 1,000,000 tons of CO_2 will be captured annually without the need for water gas shift or a gas turbine firing high a syngas that is rich in hydrogen

[1] One suggestion is that on a plant with two IGCC trains syngas from one train (with 90% CO_2 removal) might be blended with syngas from the other train that had no CO_2 removal to reduce the risk associated with firing hydrogen rich syngas in a gas turbine. However, this is not operationally practical. Individual gasifiers must be linked to individual gas turbines for safe, reliable operation

An additional implication of the RFI language is that the first one million tons of CO_2 captured in a facility where DOE shares in CCS costs must be sequestered and can never be sold for enhanced oil recovery. While there is a clear need to understand how a large volume of CO_2 interacts with a sequestration repository over time, the requirement of one million tons is arbitrary. A smaller injection volume for permanent sequestration evaluation will be adequate to understand CO_2 capacity and trapping mechanisms and still allow monitoring, measurement and verification (MMV) techniques to be evaluated. Utilization of captured CO_2 in enhanced oil recovery (EOR) provides a means for early-adopters of CCS to offset some of the incremental costs associated with CCS. Utilization of CO2 in EOR will likely play an early role in many commercial deployments of CCS and excluding the first one million tons may impede the willingness of industrial companies to participate in the restructured FutureGen program

Southern Company recommendation: Rather than focus on 90% CO_2 removal, DOE should focus on the amount of CO_2 needed annually to support sequestration demonstration requirements. By not mandating a percent CO_2 capture requirement, DOE would enable "step-wise" demonstration of CCS added to IGCC plants at levels of technological risk acceptable to commercial projects and still achieve its goal of accelerating IGCC-CCS deployment. One such possible step-wise approach is to design to capture 90% of the native CO_2 in syngas as part of initial operation, with provisions to increase this initial level of capture as experience is gained and technology improves. The first step can be accomplished without water gas shift The second step requires 1 stage of shift and brings the overall CO_2 footprint of such a plant to levels near that of a natural gas fired combined cycle plant. The first step would not require any changes to the gas turbine burner and even the second step can be accomplished with minimal burner design changes. This approach is much more realistic for a commercial IGCC plant employing these technologies for the first time

Rather than a percentage removal requirement, DOE could impose a size requirement of at least 500,000 TPY of anthropogenic CO_2 capture. This amount would be sufficiently large to meet the need to demonstrate large-scale sequestration and is a reasonable requirement for DOE financial participation in a project under restructured FutureGen. This annual amount is consistent with the regional CCS demonstration program already underway with DOE support.

2. DOE must enable public policy debate and economic analyses to determine levels of CO_2 capture.

As discussed above, DOE has proposed that a restructured FutureGen program require 90% CO_2 capture However, it is not clear that 90% capture will be the economic optimum for long-term utility operation of IGCC-CCS plants. DOE should not pursue a carbon capture percentage that could become interpreted as BACT or could become a legislated standard prior to demonstration of achievable technical performance and economic analyses derived from such performance. The results of early demonstrations of CCS will help to establish the marginal costs of CO_2 capture as a function of increasing CO_2 capture percent Preliminary analyses indicate that CO_2 capture costs rise linearly until a threshold around the 50% removal level is reached. Beyond this level, marginal CO_2 capture costs rise dramatically. CO_2 capture of ~50% will make the carbon footprint of coal-based IGCC approximately equal to a combined cycle unit firing natural gas. Requiring 90% CO_2 capture as a condition of DOE participation in CCS will impose capture costs on participants beyond what is likely to be the economic optimum in commercial projects and may prejudice public policy makers in a direction that reduces, rather than enhances, the probability that clean, affordable coal-based generation will be used for power generation in the future.

Southern Company recommendation: DOE should not require 90% CO_2 capture for the restructured FutureGen program, as this level of capture is likely not the economic optimum and may become a de facto standard. Rather, DOE should allow potential participants in the restructured program to propose CO_2 capture levels based on their site-specific situation. This would allow the demonstration projects to establish the "cost-curve" for CO_2 capture and better inform debate about the economic level of CO_2 removal from coal.

3. DOE's contribution to CCS demonstration must include operations as well as capital cost considerations.

Adding CO_2 capture to a commercial power plant requires not only additional capital investment for CO_2 capture equipment, it also burdens the power plant with additional operating costs over the life of the plant. This operating cost penalty is proportional to the amount of CO_2 removal required. Requiring 90% carbon capture as a condition of DOE cost share will dramatically increase the cost of electricity from a plant equipped with CO_2 removal and reduce the plant's net power output.

Southern Company recommendation: Under a restructured FutureGen program, DOE's criteria for participation in the cost of CCS should be developed with the full economic cost of a CCS-equipped plant in mind. A private company will calculate the cost of lost generation capacity imposed by operating CO_2 capture equipment and impute that cost to any plant equipped with CCS. If the cost is too high DOE is unlikely to receive bids for participation in the restructured program.

4. The criteria specified for conventional emissions are unnecessary and may be counter-productive

The federal and state permitting process will require extremely low emissions from new coal-based power plants. This process is designed to ensure that all relevant legal emission criteria are met while accounting for the public interest for a specific plant site. The restructuring of FutureGen should be focused on increasing the likelihood of commercial demonstrations of new low carbon coal-based power generation technology. Specifying additional emission criteria as a condition of DOE participation in CCS at a new IGCC plant adds unnecessary complication without any public benefit. This is especially true since any DOE financial participation in a project will require a full review under the National Environmental Policy Act

Southern Company recommendation: Eliminate the criteria for conventional emissions. Existing permit requirements are adequate to ensure that any new IGCC plant that is built will be far cleaner than any existing coal-based power plant. Including additional criteria as a condition of DOE financial participation in CCS increases the likelihood of DOE receiving no bidders for the restructured FutureGen.

5. DOE should seek to confirm future funding for CCS under a restructured program.

Although DOE proposes up to $1.3 billion (in as-spent dollars) will be available for a restructured FutureGen program, only $156 million is presently appropriated. This amount of funding is likely to be insufficient to support more than one commercial scale CCS demonstration. Absent additional appropriations, it is unlikely that commercial entities will endeavor to bid for FutureGen projects unless it is evident that sufficient funding is available.

Southern Company recommendation: DOE should champion a larger commitment to CCS research, demonstration and deployment and work to assure that a restructured FutureGen program has sufficient authorized and appropriated funding to enable meaningful financial contributions before announcing a competitive Funding Opportunity Announcement. In this way, a restructured FutureGen program will operate similarly to the Clean Coal Power Initiative program, through forward appropriations. This will allow planning certainty for commercial project developers and operators who will seek to apply for and use these funds.

6. DOE should seek to link CCS under restructured FutureGen program to existing Regional Sequestration partnerships.

In the RFI, DOE affirms many technical goals for sequestration associated with the restructured FutureGen program. However, many of these technical goals are already being addressed by the Regional Sequestration Partnerships.

Southern Company recommendation: The restructured FutureGen program should seek to provide funding for the CO_2 capture costs associated with a sufficient amount of CO_2 to enable the Regional Partnerships to fulfill their already established technical goals. This will enable geologic storage potential and measurement, monitoring and verification (MMV) techniques to move forward as already initiated by the Regional Partnerships. The original FutureGen project has produced an outstanding set of technical results on geologic monitoring and other information of value to sequestration science. Linkage of these programs will move sequestration forward faster than moving them alone.

7. Carbon transport and storage of CO_2.

DOE requested comment on whether CO_2 transport and storage could be decoupled from power generation aspects. Southern Company recognizes that any CO_2 produced from power plant carbon capture system will, of necessity, be transported to storage via a pipeline, whether that storage is on the plant site (short distance) or some at a remote location (long distance) away from the plant. Since a pipeline will be connected to the power plant and CO_2 from power generation is required to be cleaned and compressed to pipeline conditions, the power plant will be coupled to storage efforts.

Southern Company recommendation: Southern Company has no problem with CO_2 pipeline operations being conducted by a third party, so long engineering designs can reasonably protect the power plant operations from upsets in the pipeline (and sequestration injection system) operations and so long as operational liabilities and risks can be properly allocated between power plant owner/operator and pipeline operator.

8. Carbon capture on advanced coal systems other than IGCC.

Southern Company considers IGCC with CCS is likely to be the long-term lowest cost alternative for carbon capture, provided technology hurdles (H2 turbines, WGS, CO2 regeneration costs) can be reduced and performance demonstrated. However, these remain as significant technical risks and as such; it is pre-mature to reject options for other advanced coal-based systems, including CO_2 capture on post-combustion and oxy-combustion. Combustion based systems, if they can be demonstrated as cost-effective, may enable retrofit to the existing coal-fleet and may offer a technology alternative to gas turbine based systems.

Southern Company recommendation: Allow for multiple technology demonstrations of pre-combustion, post-combustion and oxy-combustion are conducted provided such demonstrations show adequate economic potential.

9. REDACTED

REDACTED

UNITED STATES DEPARTMENT OF ENERGY

REQUEST FOR INFORMATION
ON
USDOE'S PLAN TO RESTRUCTURE FUTUREGEN

SUBMISSION OF THE SUMMIT POWER GROUP
March 3, 2008

The Summit Power Group ("Summit") welcomes this opportunity to submit comments in response to the Department's ("USDOE's") plan to restructure FutureGen. Summit supports USDOE's plan, and – as an active developer of integrated gasification combined cycle ("IGCC") power projects – offers suggestions here for improving the plan's design in a manner that will achieve real-world results and help accomplish USDOE's objectives.

A. Background: The Summit Power Group & Its Gasification Projects

Summit was founded in the early 1990s by its current Chairman, Donald Paul Hodel, and its current CEO and President, Earl Gjelde Mr. Hodel had previously served as Secretary of the USDOE and later Secretary of the U.S Department of the Interior ("USDOI") under President Ronald Reagan, and Administrator of the Bonneville Power Administration ("BPA"), the largest Federal power marketing agency Mr. Gjelde had served with Mr. Hodel as his top deputy at USDOE and USDOI, and earlier as the Acting Administrator, Deputy Administrator, and Power Manager of BPA

Summit develops power projects for utilities, independent power producers, private equity companies, and other owners of such projects. Summit is paid on a success fee basis, and has successfully completed some five billion dollars ($5 billion) in

U.S. power projects, primarily with Siemens equipment, with an even larger portfolio of current projects in development.

Summit has three main business lines: (1) combined cycle combustion turbine ("CCCT") projects, (2) alternative energy projects such as wind power and solar power, and (3) coal gasification power projects with carbon capture. All of these business lines involve climate-friendly energy technologies of potential worldwide significance, and all help the United States achieve energy security and independence.

Summit's gasification power projects with carbon capture that are currently in development fall into three categories:

1. Large scale surface gasification projects. Summit has been working for several years with Siemens and Linde on a large scale IGCC project known as the Texas Clean Energy Project ("TCEP"). TCEP will be owned by a large private equity investor in the North American power sector. TCEP will include four (4) five hundred megawatt thermal (500 MWTh) Siemens gasifiers and state-of-the-art Siemens F-class power generation equipment operated in combined cycle. The project's expected capital cost is roughly two and a half billion dollars ($2.5 billion). TCEP will produce electric power, carbon dioxide (CO_2) for enhanced oil recovery ("EOR") and carbon capture and sequestration ("CCS"), and a variety of other commercial products and by-products. Summit expects to announce TCEP publicly, as well as the project's location, in the near future. Summit is also in discussions to develop additional large scale surface gasification projects for other parties elsewhere.

2. Industrial scale surface gasification project. Summit is working for a major worldwide manufacturing company on the design and feasibility analysis for a potential

industrial scale surface gasification project for on-site as well as other applications. The project will include two (2) Siemens 500 MWTh gasifiers and smaller than F-class generation equipment operated in combined cycle. In addition to electric power, the project will produce hydrogen and other gases for the host manufacturing facility, as well as excess synthesis gas ("syngas") for potential sale to ethanol manufacturers or others. If this project proceeds, it should be announced publicly in mid-2008.

3. Underground coal gasification ("UCG") on-site power projects. Summit has agreed to develop the power projects for at least the first three North American underground coal gasification projects of Laurus Energy. Laurus Energy is the exclusive Canadian and non-exclusive U.S. licensee of the proprietary Ergo Exergy UCG process, which has successfully produced air-blown syngas in the West in Australia and South Africa. Both Siemens and General Electric will warrant their turbines to operate on this syngas. Summit also expects to be involved in power plant development for UCG projects outside North America.

In addition to the foregoing, Summit is considering potential involvement with several advanced coal gasification technology companies whose technologies have not yet been deployed at commercial scale.

B. Summit's Comments on USDOE's Plan: Major Points

Summit believes USDOE is wise to support CCS at commercial IGCC projects, rather than just in experimental or research projects. IGCC technology is ready for commercial deployment now. What's needed is acceptable carbon management for IGCC projects, and proof to the world (and the industry) that CCS actually works. In the absence of a settled Federal legislative policy (and international policy) on carbon emissions, including policies that will help support CCS by market mechanisms, USDOE support for CCS at commercial IGCC projects may be very helpful.

Summit offers three major suggestions to USDOE in this respect:

1. <u>USDOE should not demand ninety or ninety-five percent (90-95%) carbon capture from this first generation of commercial IGCC projects. Instead, the applicable requirement should be that the IGCC project is designed to capture sufficient carbon to allow it to meet a reasonable natural gas-fired combined cycle (or "NGCC") CO2 emissions standard, recently established by California and Washington, among others, at eleven hundred pounds of CO2 per megawatthour ("MWh") of net power produced.</u>

The importance of this point can hardly be overstated. The first generation of IGCC projects involves many early-stage costs that can seriously hamper commercialization. Second and third generation IGCC plants will face fewer such costs, reflecting additional economies and optimization in design and operation that can come about only based on the experience of the first-generation plants, the capturing of economies of scale, and the development of reference plant designs.

The first-generation IGCC plants should not be saddled with excess costs that are not necessary for society's and USDOE's purposes. It should be enough, for now, that the first IGCC plants in commercial operation are designed to emit no more CO2 than an NGCC. NGCCs emit much less CO2 than conventional coal-burning plants. NGCCs are also the type of plant now being built across the country to replace coal-fired plants that are being canceled.

To achieve the NGCC standard of 1100 pounds of CO2 per MWh of net output, an IGCC project must capture between fifty-five percent (55%) and sixty-five percent

(65%) of the carbon in its syngas. This amount can be achieved through a combination of acid gas cleanup (for sulfur removal, but also removing CO2) and a water-gas shift reactor. It is not possible to achieve 90-95% removal without the addition of significantly greater shift reaction capacity. This adds significant capital and operating costs to the IGCC project. For most if not all first generation IGCC projects, those added costs are potential straws that can break the back of the project's pro forma, making the project impossible to fund, develop, finance, and build

2. <u>Use of anthropogenic CO2 for enhanced oil recovery should be considered appropriate CCS for all purposes, to the extent that the injected CO_2 is removed from the produced oil, reinjected, and ultimately is confined underground, provided that the EOR project(s) in which such CO2 is used include appropriate monitoring, measurement, and verification ("MMV").</u>

In the long run, EOR cannot entirely take the place of other forms of CCS, since the amount of CO2 that will ultimately be sequestered on a nation-wide and world-wide basis exceeds the amount that could be used in currently estimated EOR opportunities. But use of anthropogenic CO2 for EOR represents an important bridging strategy for commercialization of IGCC with CCS At the moment, the absence of settled carbon policies that might provide IGCC projects with market incentives to help cover the costs of EOR means that such projects have few if any sources of revenue, apart from EOR, to help defray those costs

Some injected CO_2 may be released to the atmosphere during the oil production resulting from EOR. Operating fields to achieve and demonstrate CO_2 storage also was not, perhaps, a priority of the industry prior to climate concerns making apparent the importance of such permanence However, the oil and gas industry is capable of providing MMV, satisfactory to regulators, and demonstrating that proper oil field management can result in a very high percentage of EOR-injected CO2 remaining trapped underground, effectively permanently for climate purposes. Given that EOR may be vital to the economics of the first generation of IGCC projects, it should be viewed as an appropriate form of carbon sequestration, despite the potential release of relatively insignificant volumes of CO_2 during the cycling of the gas that is inherent to EOR operations.

There is also no sound basis for disfavoring use of anthropogenic CO2 for EOR on grounds that the effect of injecting such CO2 into oil fields is to bring more hydrocarbons to the surface, the carbon from which eventually ends up in the atmosphere. First, producing oil with EOR methods does not increase either the demand for or the consumption of oil. Current climate modeling assumes that oil to meet current demands will continue to be produced, and that carbon from that oil will end up in the atmosphere EOR as a means of production has no impact on climate projections, and does not facilitate the addition of CO2 to the atmosphere that is not expected and already taken into account in those projections.

Second, if CO2 is not used for EOR, then other substances, including other gases, will be. Use of CO2 (compared with, say, water or nitrogen) is one way of putting carbon into effectively permanent sequestration in the process of recovering oil.

Finally, of course, EOR is conducted today using CO2, the vast majority of which occurs naturally in underground formations This CO2 is not anthropogenic. It is actually being removed from geological sequestration in the first instance. To the extent anthropogenic CO2 used for EOR can displace and ultimately replace non-anthropogenic CO2 used for EOR, the net carbon emissions reduction and climate benefits are large. It is for this reason that Texas, for example, has adopted a statute to incentivize the use of anthropogenic CO2 for EOR by reducing taxes on the oil recovered using such CO2.

3. Petcoke should not be disfavored as an IGCC feedstock, at least if blended with coal, lignite, or similar hydrocarbons. In some first generation commercial IGCC projects, petcoke may be necessary or useful to make the project's physical or financial performance acceptable. Petcoke has a high Btu content, it is dry, and although it has a relatively high sulfur content the gasification process is capable of removing that sulfur.

Moreover, petcoke is a domestic energy resource. By using it, rather than by treating it as waste product or exporting it, we improve U.S. energy security and independence.

In addition, gasifying petcoke in an IGCC project with partial carbon capture means that less carbon is released to the atmosphere than would be the case if, for example, the petcoke is burned – which is the most likely other use of petcoke domestically.

Finally, the carbon in petcoke is carbon that comes from oil that has already been produced. World climate models assume this carbon will end up in the atmosphere. To the extent the petcoke is gasified and a majority of its carbon captured in an IGCC project designed to meets the NGCC emissions standard for CO2, the atmosphere receives less CO2 than currently assumed in world climate models. The benefit from any given IGCC project may be relatively small, but it represents movement in the right direction, and is real.

C. Other Points

1. Integration of CCS and EOR: USDOE should encourage projects for saline injection of CO_2, or other forms of geologic CCS, to be designed and developed in conjunction with the use of CO_2 for EOR. These should not be considered entirely separate activities if they can be integrated. Integration is not simple, since the requirements of EOR projects and those of CCS projects are not identical. But integration can reduce total capital and operating costs. This can improve project economics for the IGCC plant, the EOR project, and the CCS project alike. Importantly, this can also allow any USDOE financial contribution to integrated CCS and EOR infrastructure to be doubly effective in helping commercialize first generation IGCC projects that include EOR and CCS.

2. Sulfur removal: It is a mistake for USDOE to continue to focus on sulfur removal in terms of the *percentage of sulfur removed*. The important criterion should be an IGCC project's ability to meet a specific standard for the allowable level of sulfur emissions *that remain*. What matters to human health and the environment is how much sulfur an IGCC plant emits, not how much it does not emit. Continuing to employ USDOE's "percentage of sulfur removed" standard simply discriminates against IGCC projects using low-sulfur feedstocks – for no legitimate environmental or other public policy purpose.

3. Avoiding the concept of gasifier "trains": The RFI speaks in terms of "one nominal 300 MW train." As you know, the concept of "trains" applies more closely to some particular gasifier technologies than others. As noted above, Summit is currently working on two IGCC projects, each of which uses multiple 500 MWTh Siemens

gasifiers These are relatively small and modular units, with two units being joined in a common manifold. These are not trains in the same sense as those of, say, the ConocoPhillips gasification technology. USDOE has no reason to favor gasifier trains over other configurations, and we ask that in its final plan, USDOE not do so.

* * *

Thank you again for the opportunity to submit this comments. Please do not hesitate to contact Summit Power if we can be of further assistance. We look forward to participating in the next stage of your process.

Sincerely,

Karl E. Mattes

Director of Projects

Summit Power

3720 Emberwood Drive

Brookfield, WI 53005

262-439-8007

kmattes@summitpower.com

DOE request for public comments regarding the plan to restructure FutureGen

Tampa Electric response:

Comments to "SUMMARY" section:

The DOE's stated objective of the restructured FutureGen is to "help understand, address, and solve technical, siting, permitting, regulatory and fiscal aspects of CCS deployment in various commercial settings". This objective is reasonable and important to enable the use of coal fueled power generation in a carbon constrained future.

The stated intent for the restructured FutureGen project is to fund "the incremental cost associated with CCS technology ". This needs to be more fully defined. The incremental costs will include the initial capital for the CCS equipment, ongoing expenses for operation and maintenance of this equipment, the expense of additional fuel required due to heat rate degradation, the cost of replacement power due to capacity degradation and any expense associated with CCS permitting and long term liability for the sequestered CO_2

Comments to "KEY GOALS OF REVISED FUTUREGEN" section:

The description of revised approach describes the characteristics that would be required for projects to qualify for participation and funding. These qualifying characteristics are aggressive and will create a significant economic burden for participating entities In particular, the requirement for 90 percent CO_2 capture will dictate significant changes to plant equipment affecting not only initial capital expense but also plant output and efficiency The DOE may want to consider projects that do not meet the 90% capture and one million metric tons of CO_2 per year targets if the alternative project can demonstrate CCS in a meaningful way on an accelerated timeline

The performance targets of >99% sulfur removal, < 0.05 lb/million Btu NOx emissions, < 0.005 lb/million Btu particulate matter emissions and >90 percent mercury removal will be very difficult for existing facilities to achieve. The department may want to consider lower standards for projects at existing IGCC facilities in order to demonstrate CCS in a meaningful way on an accelerated timeline.

The stated goals may not adequately stress the importance of establishing permitting guidelines and procedures for CO_2 sequestration.

The stated goals may not adequately stress the importance of developing mechanisms to deal with the long term liability associated with the sequestered CO_2.

The stated goals may not adequately stress the importance of the process needed to gain public acceptance of local CO_2 sequestration.

Description of potential project in response to RFI:

- Name, Point of Contact, Telephone Number, Mailing Address, E-Mail Address

  Robert Howell
  813-229-1932
  702 N. Franklin St.
  Tampa, Fl 33601
  RNHOWELL@TECOENERGY.COM

- Location of project.

  Polk Power Station
  Mulberry FL

- Narrative description of project that includes the status of project development and the technical and financial qualifications of the project team to conduct the project.

  Demonstration of CO_2 capture and sequestration below the site in a deep saline aquifer at an operating IGCC power facility.

  The proposed project would proceed in two phases.

  Phase one would entail the capture of approximately 15,000 tons per year of CO_2 from the MDEA stripper overhead gas stream. The captured CO_2 rich stream would be passed through an additional sulfur removal step prior to compression and below site sequestration. Implementation of this project would offer significant benefits:

  1. This project would demonstrate CCS from an operating IGCC power facility in the thousands of tons of CO_2 per year scale in a much shorter time frame than would be possible by waiting for new projects to reach commercial operation.
  2. This project would demonstrate CO_2 storage in a deep saline aquifer directly below the site and would be the first of its kind project in Florida.
  3. This project would become a mechanism to address the policy issues regarding long term CO_2 storage in Florida.
  4. This project would become a mechanism to establish permitting guidelines regarding long term CO_2 storage in Florida.
  5. This project would become a vehicle for public communication and outreach regarding long term CO_2 storage in Florida and nationally.
  6. The demonstration of CCS at the scale proposed by this project would significantly reduce the costs and impacts due to efficiency and capacity impacts on the operating facility

  Phase two of the project, contingent on acceptable results from phase one would be an expansion of the CCS system to approximately 400,000 tons per year of CO_2. This would be accomplished by the addition of a second amine absorption/stripping system downstream of the sulfur removal system that would be optimized for CO_2 removal.

- Discussion of the company's ability to meet or exceed the time frame set forth in the above schedule.

  Tampa Electric has over 11 years of experience in designing, constructing and operating an IGCC power facility. The proposed project would utilize Polk Unit 1, which is one of only two facilities of its kind in the US and is known world wide as a leader in technology innovation. By using this existing facility, this project can achieve the objectives of a significant demonstration of CCS in a significantly shorter time frame than other projects.

- Estimated amount of DOE contribution (in percentage and/or dollars) that would be required for the company to pursue the project with IGCC-CCS technology.
  Tampa Electric would look at this project as a joint venture with Electric Power Research Institute (EPRI) for additional co-funding opportunities. It is not know at this time the cost break out to facilitate the project.

- Any technological, financial, or legal issues or barriers that DOE should be made aware of that limit the effectiveness or feasibility of DOE's restructured approach to FutureGen.

  The stated intent for the restructured FutureGen project is to fund "the incremental cost associated with CCS technology ". This needs to be more fully defined. The incremental costs will include the initial capital for the CCS equipment, ongoing expenses for operation and maintenance of this equipment, the expense of additional fuel required due to heat rate degradation, the cost of replacement power due to capacity degradation and any expense associated with CCS permitting and long term liability for the sequestered CO_2.

- Other information or concerns that would assist DOE in implementing the revised Future Gen.

TENASKA TRAILBLAZER PARTNERS, LLC

1701 E Lamar Blvd., Suite 100
Arlington, Texas 76006
817-462-1500
FAX: 817-462-1510

March 3, 2008

VIA E-MAIL
Keith Miles
U.S. Department of Energy
National Energy Technology Laboratory
Keith.Miles@NETL.DOE.GOV

Re: Request for Information on the Department of Energy's Plan to Restructure FutureGen

Dear Mr. Miles:

Tenaska, Inc. is a privately held company with more than 20 years of power plant development and energy marketing experience. Based on the company's belief that coal-fueled power plants are essential to our nation's continued economic well being, and that such plants will be required to capture and sequester carbon dioxide ("CO_2") in the near future, two Tenaska affiliates have begun the development of advanced clean coal generating stations.

The Taylorville Energy Center is a bituminous coal-fueled Integrated Gasification Combined Cycle ("IGCC") located in Taylorville, Illinois. It is being developed by Christian County Generation, L.L.C., whose membership interests are owned 50% by MDL Holding Company, L.L.C. and 50% by Tenaska Taylorville, LCC. Due to the joint ownership of this project, Christian County Generation's response to this Request for Information is being provided separately.

Another Tenaska, Inc. affiliate, Tenaska Trailblazer Partners, LLC, is developing a supercritical pulverized coal-fueled electric generating station in Nolan County, Texas, that will capture 85% to 90% of the CO_2 produced during normal operation. Although the Tenaska Trailblazer Energy Center ("TTEC") will not employ IGCC technology, it will help further FutureGen's primary goal to demonstrate advanced technology that produces electricity from coal in a way that mitigates the atmospheric emissions of CO2. Therefore, Tenaska respectfully requests that DOE consider the Tenaska Trailblazer Energy Center for inclusion in the restructured FutureGen initiative.

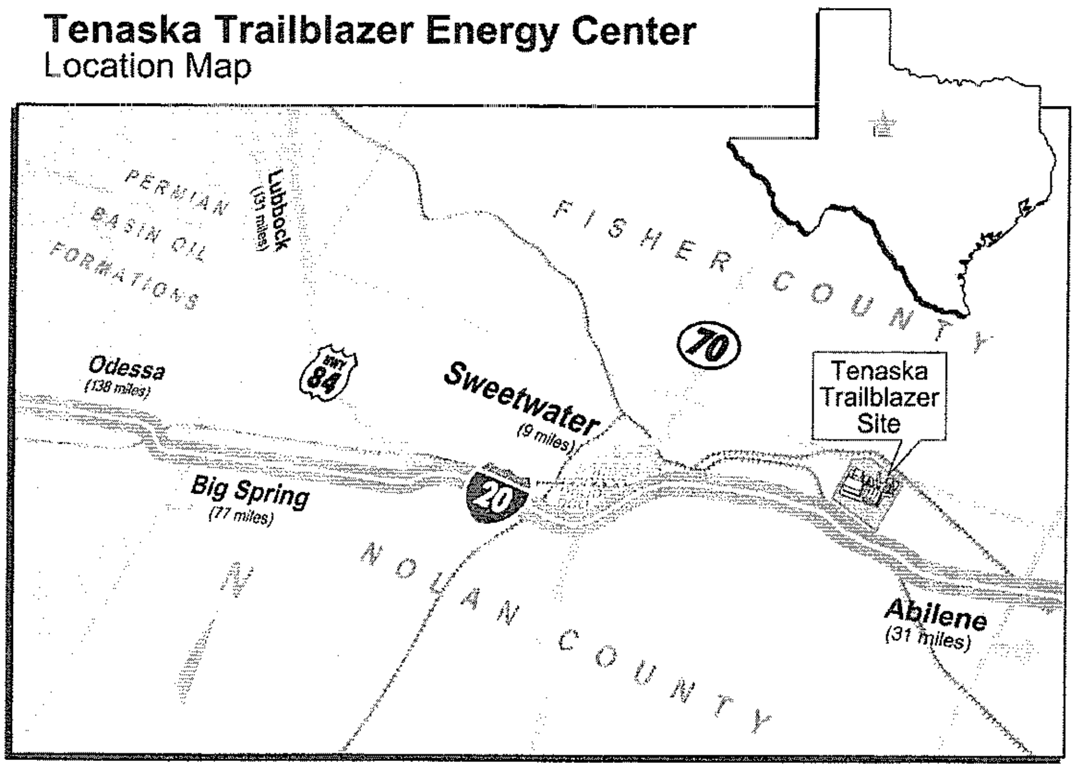
Following is the information requested in the RFI for the TTEC:

Name, Point of Contact, Telephone Number, Mailing Address, Email Address

Tenaska Trailblazer Energy Center
Jeff James
Director, Business Development
Tenaska, Inc.
1701 E. Lamar Blvd., Suite 100
Arlington, TX 76006
817/303-3600
jjames@tnsk.com

Location of project

The Tenaska Trailblazer Energy Center will be located nine miles east of Sweetwater, Texas in Nolan County. It will be electrically interconnected with the Electric Reliability Council of Texas (ERCOT).



Narrative description of project that includes the status of project development and the technical and financial qualifications of the project team to conduct the project.

A. Project Description

TTEC is a proposed supercritical pulverized coal project to be located approximately nine miles east of Sweetwater, Texas. It is being developed by Tenaska Trailblazer Partners, LLC, an affiliate of Tenaska, Inc (collectively with affiliates, "Tenaska") The TTEC will install equipment during its initial construction to capture up to 90% of the carbon dioxide produced during the combustion process. The base case assumes that the project will be dry cooled; with dry cooling, the project's gross output is expected to be 765 MW and its net output is expected to be 600 MW. If the project is able to find a suitable water source to allow wet cooling, the gross output is expected to be 785 MW and the net output is expected to be 630 MW. The expected cost of the TTEC with carbon capture and dry cooling is more than $3 billion.

The project will use sub-bituminous coal from the Powder River Basin, which will be brought to the project site via rail. A Tenaska affiliate has purchased a 1,919-acre parcel of undeveloped ranchland for the project that is bordered on the north by the Union Pacific Railroad and on the south by the Burlington Northern-Santa Fe railroad. All required rail infrastructure for the project will be built on Tenaska-owned land

Tenaska is evaluating several different carbon capture technologies, including conventional amine, advanced amine, aqueous ammonia and chilled ammonia technologies. The ultimate selection of carbon capture technology will be based on performance, scalability, economics, timing and financability. Tenaska is confident that one or more of these carbon capture technologies will be suitable for the TTEC.

B. Project Development Timeline

The development timeline for major TTEC activities is as follows:

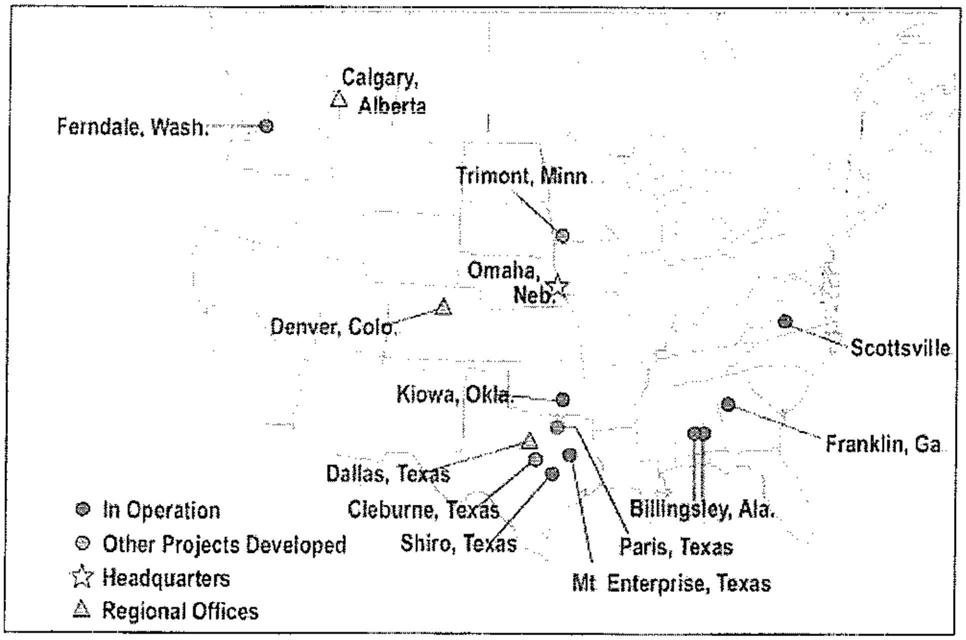
Activity	Status	Scheduled Completion
Secure site	Completed	-
Phase I & II Environmental Assessment	Completed	-
Establish plant configuration and location	Completed	-
Execute EPC contract	Not begun	January 2009
Determine and contract for water supply	In process	February 2009
Obtain transmission interconnection	In process	February 2009
Execute plant O&M services agreement	Not begun	April 2009
Execute power off-take agreements	In process	April 2009
Execute CO2 off-take agreements	In process	April 2009
Obtain permits	In process	April 2009
Financial Close	Not begun	August 2009
Provide notice to proceed to EPC contractor	Not begun	August 2009
Commercial Operation	Not begun	June 2014

C. Developer Qualifications

Tenaska is a privately held company with more than 20 years of power plant development and energy marketing experience. In 2006, *Forbes* magazine ranked Tenaska 26th largest among the top 100 privately held companies in the United States based on revenues.

Tenaska has developed and constructed approximately 9,000 MW of generation representing more than $7.7 billion in financing and capital investment. Unlike most other independent power developers, Tenaska has maintained a strict discipline of incurring debt only through non-recourse debt at the project level. Accordingly, Tenaska, Inc. is debt free. This strong financial position provides assurance to Tenaska's counterparties that the organization will remain financially stable and strong.

The following map shows the breadth of Tenaska's operations and experience



Tenaska employees have experience in all aspects of large-scale generating project development, including combined and simple cycle natural gas facilities, pulverized coal, fluidized-bed, waste coal and lignite facilities. Tenaska employees have experience in gas and coal plant siting and permitting; engineering design and optimization; financing; construction contracting and management; fuel procurement and handling; commissioning; and operations and maintenance.

Tenaska Marketing Ventures, a Tenaska affiliate is among the top 10 daily marketers in the North American natural gas market, selling or managing more than 1.86 trillion cubic feet of natural gas in 2007. This volume is equivalent to approximately eight percent of total U.S. natural gas consumption. Tenaska also has a power marketing affiliate, Tenaska Power Services, that develops custom power supply solutions for its customers. It operates a 24-hour trading floor dealing primarily with sales of physical electric power, totaling more than 15,615 gigawatt-hours of electricity sales in 2007.

Tenaska is headquartered in Omaha, Nebraska. Regional offices are in Arlington, Texas; Denver, Colorado; and Calgary, Alberta, Canada.

D. *Project Financing*

The TTEC will be funded by the following sources:

- **Equity**. Tenaska, and possibly other partners, will fund a significant portion of the total required funds.
- **Financial Institutions** Tenaska expects to obtain the non-equity portion of the project funds from the commercial bank market.

Discussion of the company's ability to meet or exceed the time frame set forth in the above schedule.

The DOE is contemplating a project with a commercial operation date of 2015. The TTEC's current proposed commercial operation date is June 2014, but does not contemplate a National Environmental Policy Act (NEPA) review. If a NEPA review is required we expect this would delay our commercial operation date until June 2015.

Estimate the amount of DOE contribution (in percentage and/or dollars) that would be required for the company to pursue the project with IGCC-CCS technology.

Although the TTEC does not plan to use IGCC technology, it does intend to install and operate CCS technology from day one. We have just completed the first phase of our development period with the filing of: 1) the TTEC air permit application and 2) the TTEC transmission interconnect request. We are now entering the second phase of development, which involves plant design work, obtaining engineering and construction bids and determination of ultimate financial viability. Tenaska will spend more than $15 million during this second phase – a considerable commitment to the development of the TTEC. Some of this phase two effort must be completed before we can determine the amount of DOE contribution that would be required for Tenaska to pursue CCS at the TTEC

Any technological, financial or legal issues or barriers that DOE should be made aware of that limit the effectiveness or feasibility of DOE's restructured approach to FutureGen.

In the absence of a specific statutory exception, DOE grants constitute taxable income to the recipient. This was not an issue when the recipient of DOE funding was to have been a not for profit corporation, but it will be an issue in the funding of commercial projects. In order to preserve the full amount of any potential funding to pay for the capital cost of capture and sequestration, it would be desirable for DOE to pursue a legislative exemption with Congress.

Other information or concerns that would assist DOE in implementing the revised FutureGen.

As mentioned above, TTEC is not planning to use IGCC technology. DOE should consider FutureGen funding for at least one project that contemplates capture and sequestration of carbon dioxide in a post combustion configuration. It is important for this country to find a way to capture CO2 in a post combustion configuration, since most all of the coal-fueled projects in this country do not utilize IGCC technology.

Tenaska believes the carbon transport and storage of CO2 may reasonably be decoupled from the power generation aspects of the TTEC and performed by separate entities

Sincerely,

TENASKA TRAILBLAZER PARTNERS, LLC
By: Tenaska Trailblazer I, LLC, its Managing Member

By: David G. Fiorelli
President & CEO, Business Development

Wallula Energy Resource Center (WERC) Project
Response to Department of Energy
Request for Information to Restructure FutureGen

Point of Contact

Robert E. Divers, CEO, United Power Company, LLC
3202 Harbor View Drive NW, P.O. Box 2089, Gig Harbor, WA 98335
Phone 253-853-1669, Cell 253-431-9250
E-Mail Address rdivers@unitedpowerco.com

Location of Project

The WERC Integrated Gasification Combined Cycle Project will be located on a greenfield site in the Wallula Gap Business Park, Walla Walla County, Washington. The project is approximately 11 miles southeast of the city of Pasco, WA, 1 mile east of U.S. Highway 12, approximately 1.75 miles north of the town of Wallula and 1.25 miles east of the Columbia River.

Project Description

Power Block

The WERC project 2x1 configuration power block consists of two Mitsubishi Power Systems (Mitsubishi) Model 501 G combustion gas turbine generators each with a Heat Recovery Steam Generator (HRSG) and one Mitsubishi Power Systems single reheat, condensing steam turbine generator receiving steam from each HRSG. At full load operation and average ambient site conditions, each combustion gas turbine will produce 268,700 KW gross and the steam turbine 376,700 KW gross for a total facility gross output of 914,100 KW. The auxiliary power consumption is estimated at 215,900 KW for a net plant output of 698,200 KW. The gross efficiency is 42.7 % and the net efficiency is 32.6 %. The project is located at an elevation of 500 feet above sea level with an average annual temperature of 54 F and 71 % relative humidity. The main power train cooling system will use wet mechanical-draft cooling towers and inlet evaporative cooling will be used to maximize combustion gas turbine output for peak summer operating conditions.

Gasification Block

Up to 3.2 million tons per year of Powder River Basin (PRB) coal will be utilized as the primary fuel feed and natural gas will be utilized as back-up, start-up and shut-down fuel. The project will be operated primarily on hydrogen rich (low carbon) fuels that have CO2 emissions that are less than a modern natural gas-fired combined cycle gas power plant. The coal will be gasified using Mitsubishi two train air blown dry feed, membrane waterwall gasification technology to produce synthesis gas (syngas), a high purity carbon dioxide (CO_2) for sequestration, and slag, elemental sulfur and ammonia byproducts for sale to third parties. See attached block diagram entitled "WERC 700 MW IGCC with Integrated CO_2 Capture (Avg. Ambient 54 F)" for a block representation of the WERC gasification process.

Mitsubishi's air blown dry feed, membrane waterwall gasification technology is a unique gasification process that has been under development for over 20 years in Japan. It was developed exclusively to provide the power industry with the most efficient IGCC technology.

The MHI technology was selected for the WERC project design due to the ability to fire low cost PRB fuels, the use of an air blown design which reduces auxiliary power, a dry coal feed which lowers the heat loss and reduces water demand resulting in increased efficiency, and the use of water wall construction which removes the requirement for high maintenance refractory thus increasing plant availability. In addition, the Mitsubishi gasifier is smaller than other technologies which allow the complete gasifier vessel to be shipped by barge to the site in one piece thus reducing construction costs. The Mitsubishi gasification process technology using PRB fuels is currently under testing in a 250 MW demonstration plant in Japan. This plant has been in start-up operations since the fall of 2007 and to date all systems have proven to run as designed. The test program will be completed this spring with the test results used in the final design of the WERC project. A cooling system utilizing wet mechanical-draft cooling towers will be provided for the gasifier process and combined cycle power-island.

<u>Carbon Sequestration</u>

Sixty-five percent of the CO_2 produced in the gasification process (approximately 4 million tons per year) will be captured by a Selexol (ARG) unit, pressurized to approximately 2,200 psig and injected into the Grande Ronde #5 basalt formation located directly under the site where the pressurized CO_2 will convert to a solid carbonate and remain in permanent sequestration. The injection well(s) will be located on or near the project site. The site is positioned above approximately 12,000 to 14,000 feet of basalt that is available for sequestration. The WERC project is partnering with the Big Sky Carbon Sequestration Partnership (Big Sky), one of seven DOE partnerships, U.S. Department of Energy, Battelle Institute, Pacific Northwest Labs, the Port of Walla Walla and others to provide the project site as the study site for sequestering CO_2 into basalt formations. The formal on-site testing was started in the summer of 2007 with the test results to be obtained over the next two years. Please refer to the attached document entitled "Field Activity Plan: Characterization Test for CO_2 Sequestration in the Columbia River Basalt Group, dated June 2007" for details of the basalt sequestration program and anticipated results. We believe this will be the first large scale IGCC project sequestering CO_2 in basalt.

The sixty-five percent CO_2 sequestration design was selected as the break between a traditional low Btu fuel combustion gas turbine design with a history of operating experience and a new, lower Btu hydrogen based fuel gas turbine design with little design experience in combustion gas turbines of this size. The WERC project team did not want to accept both risks for a new gasification technology and a new gas turbine technology for a plant that will cost in excess of $3 billion dollars. Mitsubishi has extensive operating experience with low Btu combustion gas turbines of the type selected for this project. There is no operating experience with the low Btu hydrogen based technology. Additionally, the low Btu hydrogen fuel will result in lower plant efficiency thus further compounding the operating cost difference between an IGCC plant design and a traditional natural gas-fired combined cycle design which is the marginal cost competitor for base load operation.

Transportation Systems

PRB coal will be transported from the Wyoming mines to the site by one of two railroads (Burlington Northern & Santa Fe Railway or the Union Pacific Railroad) which have a common tie located adjacent to the site. The common tie will allow coal delivery competition thus reducing fuel delivery costs. Approximately 5 unit trains of 150 cars each will be run to the site per week. The WERC project is also being designed to burn a range of PRB coals thus further allowing coal purchase price flexibility. The same coal supply transportation system will be used to transport slag and sulfur byproducts off-site to third party customers. Ammonia byproducts will be transported to local customers by truck.

Natural gas will be supplied from the existing TransCanada GTN System (GTN) main pipeline which is located approximately 4 miles south and east of the site

See Figure 2.2.3.2-5 entitled Transmission, Makeup Water and Gas Routing for a representation of the rail and natural gas transportation systems.

Electric Transmission System

Electric transmission services for the WERC project will be through Bonneville Power Administration (BPA). A three mile 500 kV transmission line and substation will need to be constructed from the WERC project site to the existing main BPA Lower Monumental to McNary 500 kV transmission line. A System Impact Study has been performed which indicates the feasibility of this design. See Figure 2.2.3.2-5 entitled Transmission, Makeup Water and Gas Routing for a representation of the proposed electric transmission system

Water Supply and Discharge

Water for the project will come from the Wallula Business Park municipal water system. An annual average 4,000 gpm is required for the WERC project. The plant is being designed as a zero discharge plant with all water collected, treated and reused except for a small stream of brine flow to an on-site evaporation pond where the liquid portion will be evaporated and the solids transported to an approved land fill. The only other liquid discharge is sanitary waste through an approved septic system.

Project Access

Access to the project site will be a network of country roads off of U.S Highway 12 which is located approximately 1 mile from the project site.

Air Emissions

The WERC project is located in an air quality attainment area. In addition to reducing CO_2 emissions, preliminary air modeling has indicated that the WERC Project will have emissions closely approximating a natural gas fired power plant meeting all federal, state and local air quality requirements. Mercury emissions will be reduced to the stringent proposed Washington state limits and the sulfur in the syngas will be substantially reduced (to 10 ppmv total sulfur) to enable effective utilization of SCR, concurrently achieving very low sulfur emissions

Status of Project Development

The following activities have been started or completed:

- Mitsubishi and Fluor Enterprises, Inc. (Fluor) have been selected as the design team and equipment providers.
- A complete Feasibility Study including cost estimates has been completed by Mitsubishi and Fluor.
- An outline of the FEED Study to be performed by Mitsubishi and Fluor has been agreed to
- Preliminary negotiations have been completed for the land and water supply with the Port of Walla Walla, the owner of the Wallula Gap Business Park
- Agreement has been achieved and work started by Big Sky to prove the science of carbon capture in basalt on the project site.
- A potential Site Study has begun with EFSEC (the Washington State Energy Facility Site Evaluation Council) which is the state wide permitting agency for thermal power projects exceeding 250 MW's) as a required precursor to a licensing application. The first EFSEC site visit is scheduled for March 13th 2008.
- A licensing application to the state of Washington has been started and is approximately 65 percent complete. Approximately 3 months remain to complete this effort Once the licensing application is submitted to EFSEC, the time to site approval from the state of Washington is 14 months.
- A System Impact Study has been completed by BPA that provides the design requirements of the 500 kV electrical interconnection with the BPA system.
- Discussions have been made with PRB coal suppliers and the railroads to confirm the availability and costs of the fuel supply.
- A detailed proforma (financial analysis) has been developed and has been used to provide answers to what if questions.
- The project is on-schedule for start-up operations in the year 2014.

Technical Qualifications

Mitsubishi is one of the top three producers of large combustion gas turbines and steam turbines in the world. The Mitsubishi "G" combustion gas turbine is one of the largest and most efficient in the industry with over 45 units presently operating. In addition, Mitsubishi has over one million operating hours of experience with large low Btu fuel firing combustion gas turbines. Mitsubishi has extensive experience in the development of IGCC plants in Japan starting with the early pilot plants (CRIEPI and Nakoso) in the 1985 to 1995 time periods to the startup and operations (this last fall) of a 250 MW demonstration plant firing PRB coal. The Mitsubishi gasifier design is based on extensive experience in the boiler industry with over 2,800 boiler units in service.

Fluor has been a top ranked engineering, design and construction company for many years and recently ranked #1 in Fortune magazine's "Engineering Construction Category of America's Largest Corporation" and Engineering news record ranked Fluor #1 in the top 100 contractors. In recent years Fluor has built over 150 combustion gas turbine generating facilities and in the last 5 years has consistently been awarded approximately 1/3 of the new combustion gas turbine projects in the U.S. In the area of gasification, Fluor has over 30 years of experience in the design, engineering and construction of gasifiers and over 80 years of experience in the petroleum refining, a related business unit that work experience can be drawn from.

Developers and Owners Qualifications

Robert Divers, CEO and managing Partner of United Power Company, LLC was lead developer of the project team that successfully licensed the 1,300 MW combined cycle Wallula Power Project and was responsible for the successful development of the 250 MW combined cycle Rathdrum Power Generation Facility. United Power has been developing the project under a joint development agreement with Edison Mission Energy, the unregulated company owned by Edison International. The parties are currently interviewing a short list of potential industry partners (coal companies and utility affiliates) who have asked to invest in the next project phase which will be the FEED study resulting in an EPC contract and a Power Purchase Agreement. This expanded going forward consortium will provide the equity for and own the completed project. The expanded project ownership group will be in place in the next 60 days.

Schedule

The project schedule consists of the following milestones:

- 3 months to complete the licensing document and submit to EFSEC – the licensing effort is 65 % complete and all information is available from the project consultants and the Mitsubishi/Fluor Feasibility Study to complete this effort
- 14 months to complete licensing and state of Washington Governor review – by law, the EFSEC review process has to be complete in a 12 month period on the assumption of a timely response to questions by the Applicant. At the end of this

process, a recommendation is made to the Governor and the Governor has up to 2 months to make a decision. The project team is working closely with the various departments in the state of Washington to keep them up to date of project activities and design data and to bring them into the process as a partner as information is developed. This process was used by the existing project team in the licensing of the 1,300 MW Wallula Natural Gas Power Project in 2002 with the result that the project was licensed in the stated time and without opposition.

- 3 to 6 months to complete agreement for construction financing – the project team is experienced and will have the information available for review by prospective power purchasers and financing companies within the required time
- 54 months after notice to proceed for plant operations – the notice to proceed will be issued after the completion of the FEED Study which is a detailed design and engineering effort of the project with a complete detailed cost estimate. The Feed Study will begin at the time of the licensing application submittal to the state of Washington and be complete by the time of construction financing. Approximately 44 months are allocated for on-site construction activities. In addition, due to the ability to construct many of the gasification modules in Japan and ship directly to the site by ship/barge, the amount of on-site construction time and activities are reduced further leading to on-time construction activities. 15 months are allowed for the FEED Study effort during which time negotiations will be performed for the EPC contract with the Mitsubishi/Fluor team. It should be noted that technology licensors, major equipment suppliers, and selected contractors for the IGCC plant and offsite facilities have been selected and are engaged in project development activities

The above schedule would result in the project achieving substantial completion in mid 2014.

Estimated Amount of Department of Energy Contribution

Incremental costs of CCS technology as estimated by Mitsubishi/Fluor are itemized as follows:

Acid gas removal system (Selexol)	$193,000,000
CO2 compressors and drying system	$ 50,000,000
CO2 collection, distribution and injection system	$ 25,000,000
Site preparation	$ 2,680,000
Construction Management and Engineering	$ 29,480,000
Other costs (transportation, vendor reps and erection services, warranty, custom and import duties)	$ 13,400,000
Contractor base fees	$ 5,360,000
Contingency	$ 13,400,000
Total	**$332,320,000**

Technological, Financial and Legal Issues/Barriers

There is one technological barrier that would preclude WERC from qualifying for the restructured approach to FutureGen. The WERC project has selected 65 percent CO2 sequestration versus the FutureGen requirement of 90 percent. As noted above, the 65 percent CO2 sequestration was based on the need to reduce project risks and improve project economics to compete with natural gas-fired combustion technologies. The project already has a significant risk in the use of a new technology (gasification process) and cannot withstand the additional risk of a new low Btu hydrogen combustion gas turbine design which has not been designed and operated for projects of the size under discussion. The WERC project team selected the combustion gas turbine vendor (Mitsubishi) with the most experience with low Btu gas firing gas turbines that the 65 percent CO2 sequestration design would require. There is little operating experience with the 90 percent CO2 sequestration design.

In addition, the IGCC design already has built in efficiency penalties and cost adders for the gasification process all leading to elevated energy operating costs Reducing the CO2 sequestration levels from the 65 percent level to the 90 percent level only increases the cost of energy production to levels that might not be cost effective with other competing technologies Care needs to be made to not only make the project technology sound but also costs competitive in order for this technology to be a part of the future generation mix in the U S

For the above reasons, the WERC project requests that the 65 percent sequestration design be considered for the restructured approach to FutureGen.

Other Information

It is our understanding that the WERC project is the only project considering CO2 sequestration in basalt. This process provides the safest CO2 sequestration design as the resulting mineralization is a solid carbonate which would be permanently locked in the basalt formation without the ability to leak back to the surface. This has CO2 sequestration implications for other countries such as India where there are large basalt formations such as in the Pacific Northwest We are advised by Big Sky that the world wide basalt storage reservoirs can hold up to 600 years of the present world's CO2 annual releases. The project team is closely working with Big Sky to provide a different approach to CO2 sequestration that would benefit not only the U.S but other basalt regions of the world most specifically India.

WERC Project Impact and Significance

When completed the WERC project will set several milestones for the power industry, the U.S and the Pacific Rim, including:

- First commercial PRB or sub-bituminous coal fueled IGCC unit of its size (nominal 700 MW net) in the world

- First commercial IGCC plant operating on coal to capture CO2 for sequestration.
- First to demonstrate storage of CO2 in the vast Western U.S. basalt formations
- Largest commercial unit of a gasification combined cycle plant designed to use PRB coal as feed stock
- First commercial unit of this size in the world using the unique and efficient Mitsubishi air blown dry feed, membrane waterwall gasification technology.
- The lowest CO_2 emitting coal fired IGCC plant of this size in the world

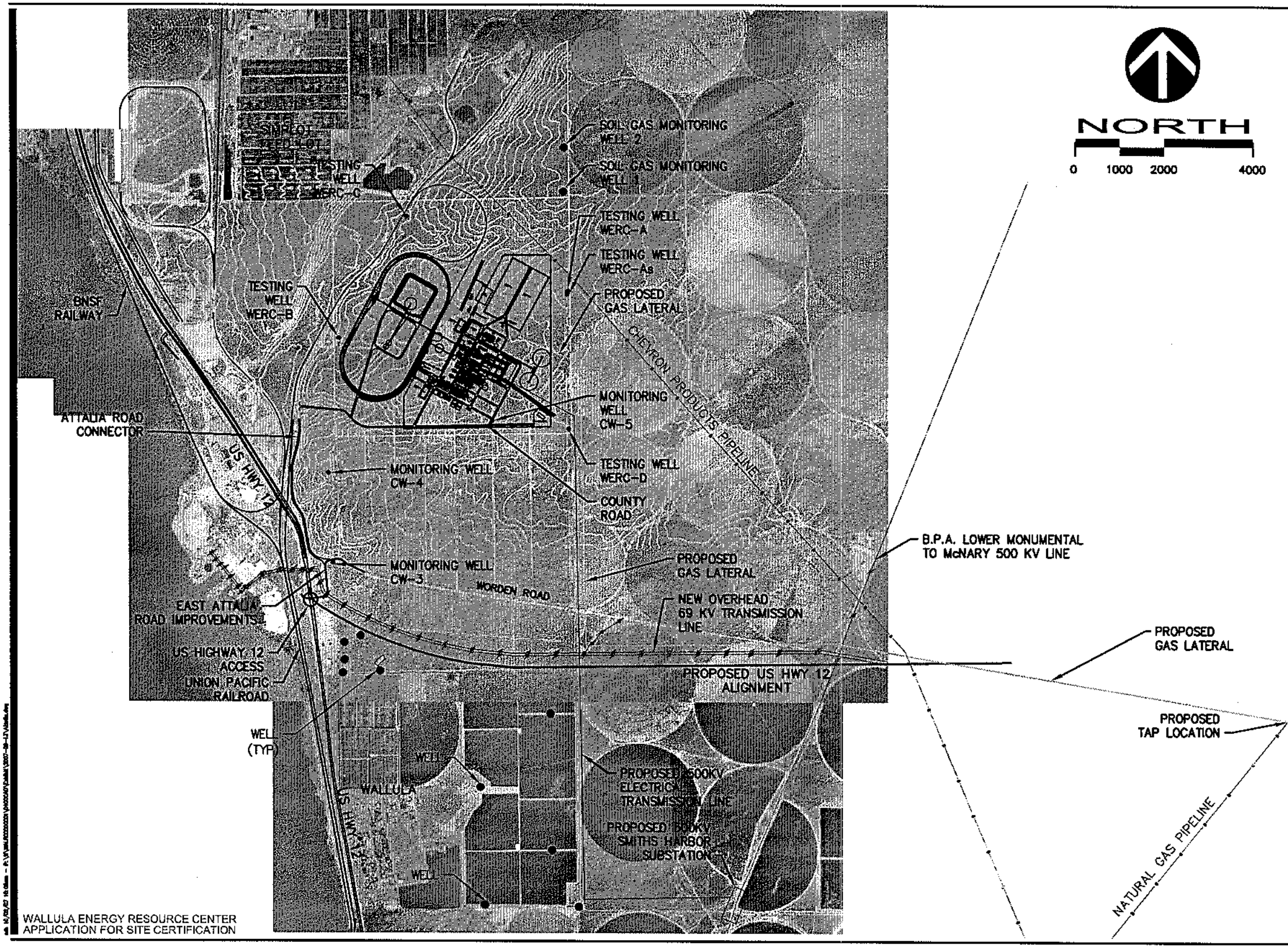


FIG. 2.2.3.2-5

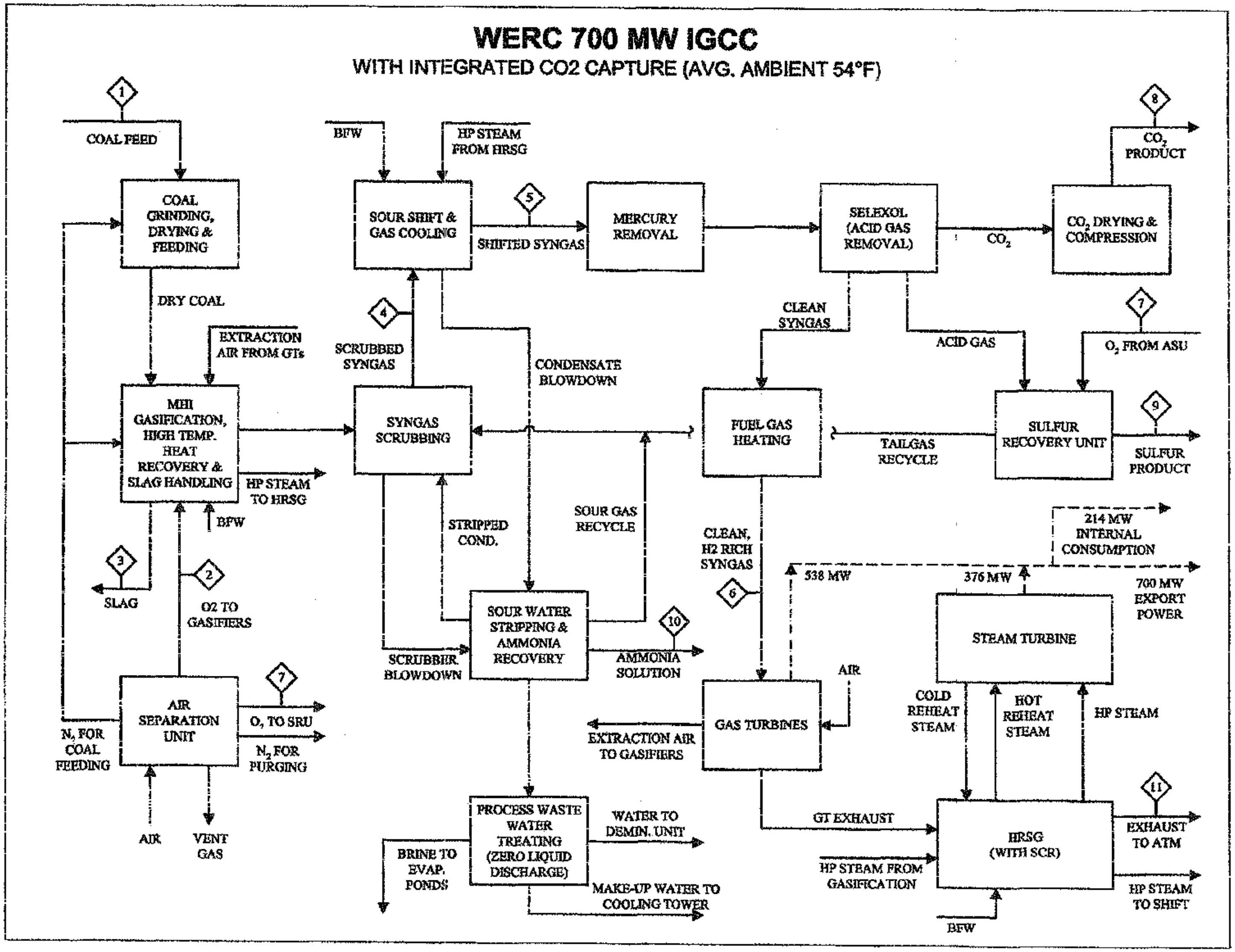
TRANSMISSION, MAKEUP WATER AND GAS ROUTING

DAVID EVANS AND ASSOCIATES INC.
3700 Pacific Hwy. East, Suite 311
Tacoma Washington 98424
Phone: 253.922.9780

WALLULA ENERGY RESOURCE CENTER
APPLICATION FOR SITE CERTIFICATION

Figure 1
Overall BFD

31 July 2007
Revision C



The Need to Demonstrate Post-combustion Capture
Comment on DOE'S restructured approach to FutureGen

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March 3, 2008

Summary

In its FOA on the restructured approach to FutureGen, DOE should explicitly allow for a 300 MW demonstration of post-combustion capture on an existing coal-fired power plant. CO_2 Capture by aqueous absorption/stripping is capable of meeting all the environmental and performance goals of FutureGen. The cost and timing of such a demonstration will be competitive with proposals that use IGCC. The demonstrated technology will be useful for both new <u>and</u> existing coal-fired power plants.

Luminant Carbon Management Program

The Luminant Carbon Management Program at the University of Texas is focused on the technical obstacles to the deployment of CO_2 capture and sequestration from flue gas by alkanolamine absorption/stripping and on integrating the design of the capture process with the aquifer storage/enhanced oil recovery process. The objective is to develop and demonstrate evolutionary improvements to monoethanolamine (MEA) absorption/stripping for CO_2 capture from coal-fired flue gas.

The Luminant Program will provide technical support for one or more proposals from our sponsoring companies to build and operate a 300 MW alkanolamine absorption/stripping process retrofitted on an existing coal-fired boiler. The Luminant Program will not seek additional funding from DOE for this technical support.

The Luminant program will provide fundamental, modeling, and pilot plant results on generic solvent and process alternatives. The scope of effort will include solvent thermodynamics and rates, solvent degradation and management, process configurations and modeling, and pilot plant testing at 0.2 MW.

The research program includes 15 PhD graduate students, 4 faculty, and 5 professionals. The effort is currently funded for five years by $500,000/yr from Luminant. LS Power is providing $100,000/yr for three years for the "LS Power Pilot Plant Initiative" of the Industrial Associates Program for CO_2 Capture by Aqueous Absorption. Additional support of more than $400,000/yr is provided by 17 Industrial Associates in the Program for CO_2 capture by aqueous absorption/stripping and the Luminant Carbon Management Program, including 7 process suppliers (Alstom Power, Babcock & Wilcox, Shell Global Solutions, IFP, Mitsubishi Heavy Industries, Cansolv, URS), 3 users (Southern Company, RWEnpower, E ON), and 7 others (AspenTech, Chevron, BP, Huntsman Chemical, CSIRO, Siemens, Battelle)

Background

CO_2 capture by absorption/stripping with aqueous monoethanolamine (MEA) is the benchmark technology for addressing CO_2 emissions from existing coal-fired power plants Conventional coal-fired power plants represent a large fraction of the existing capacity and capacity to be built before advanced power systems can be deployed. These conventional plants cannot be abandoned in any comprehensive strategy to reduce CO_2 emissions for global climate change. This technology will also be competitive with IGCC in new plants burning Texas lignite, Power River Basin, and other lower rank coals.

The MEA process is a derivative of extensively used technology for treating natural gas and hydrogen It is used commercially in combustion plants with gas rates equivalent to 20 MW. There are two commercial suppliers at this scale: Fluor and Mitsubishi. Additional suppliers for this generic technology are likely to emerge from the research sponsors of the Luminant Program

The economics of the first generation MEA technology have not been attractive The energy requirement can reduce the power output of a coal-fired plant by as much as 30%. However, the alternatives for existing coal-fired power plants can be equally unattractive. Like limestone slurry scrubbing for flue gas desulfurization, aqueous absorption/stripping for CO_2 capture is the first technology to receive serious consideration and it will survive as the primary technology to be used for this application.

The deployment of this technology will require a demonstration of CO_2 capture and sequestration on an absorber module at a commercial scale (100-300 MW). Texas has a number of existing boilers fired by lignite or PRB that would be excellent sites for such a demonstration These power plants are located on sites with excellent opportunities for geologic sequestration.

Performance Requirements

A retrofit demonstration of post-combustion capture will meet the environmental goals of the restructured FutureGen project. CO_2 capture can exceed 99%, but would be designed for 80 to 90% on an annual average. SO_2 removal will exceed 99 99%. NO_x emissions will be controlled by selective catalytic reduction Particulate emissions will be controlled by existing ESP or bag filter facilities in combination with the extensive gas/liquid contacting required for CO_2 capture Mercury will be controlled by carbon injection, if necessary implemented with an additional bag filter system.

Post-combustion capture will provide un-matched flexibility and reliability for coal use in both existing and new power plants. The demonstration can proceed quickly on a large existing coal-fired boiler with existing environmental controls. A realistic schedule could allow for start-up of carbon capture and sequestration as early as 2012. The existing plant will continue to produce power with or without successful operation of the capture system. The capture plant will be designed to be turned off during peak power demand, so that new capacity will not be required to replace energy used for the capture system.

A suitable demonstration of post-combustion technology could be as small as 100 MW or as large as 400 MW. Since most appropriate units will be 800 MW, it may be more appropriate to consider 200 MW or 400 MW for the demonstration. It does not make sense to do 800 MW at this time, but a sequentially scheduled demonstration could start with 200 MW and add up to 800 MW as the uncertainties are eliminated, funding becomes available, and legislation mandates full control.

Cost to DOE

The total capital cost of this project will be \$200 – 400 million. If the project is installed at an existing coal-fired power plant with full environmental controls, there will be little or no capital cost associated with issues other than CO2 capture. Therefore there will be less uncertainty associated with overall project financing than with the construction of a new power plant. The loss of power production for operation of the capture system will cost \$20-40/ton CO_2. In the absence of legislative mandates for CO_2 capture, DOE will need to provide most of both the capital and operating cost. The cost to DOE may be reduced in proportion to the timing and magnitude of legislative mandates for CO_2 capture.

$\alpha\beta\chi\delta$

Response to request for comments on revised FutureGen approach

From:
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Alstom Power, Inc.

Alstom Power Inc. welcomes this opportunity to submit its views on the proposed restructuring of the FutureGen program. America's long-term energy and economic security depends on the availability of a strong portfolio of clean, reliable, and economic technologies for power generation including renewables, nuclear, and clean use of fossil fuels. Alstom strongly believes that CO_2 capture and storage is critical to sustainable long-term energy supply. As such, our company is a global leader in innovative R&D to meet the technological and economic challenges of capturing CO_2. ***A policy framework that includes adequate Federal funding for technology demonstrations, coupled with incentives for early deployment, can help to accelerate commercialization of these and other crucial technologies that help utilities address CO_2 restrictions.***

Alstom has a 100$^+$ year history of providing power generation and environmental control technologies to the global electric industry. Alstom is a global specialist in energy and transportation infrastructure with annual sales of over $21 billion. In the US, Alstom has 65 locations in 22 states, including its US corporate headquarters in Windsor, CT. The company serves the energy market through its activities in power generation, power transmission and distribution, and power conversion. Alstom offers a comprehensive range of power generation solutions from turnkey plants to all types of turbine (gas, steam, hydro) generators, boilers, environmental control products and control systems, as well as a full range of services including plant modernization, maintenance and long-term operation.

Looking forward, long-term environmental sustainability places an additional standard for coal-based power – reduced carbon emissions. As a technology innovator, we firmly believe that carbon reduction, capture and sequestration technologies at competitive costs are a critical and achievable goal for coal-based power. However, realizing this goal will not be easy; it will require the combined skills and knowledge of the public and private sector, working in close cooperation over, at a minimum, the next decade.

In seeking public comment on its proposed revisions to the FutureGen program, DOE clearly demonstrates it willingness to continue to work closely with industry to develop these technologies.

Comments to RFI for FutureGen restructuring:

In the recent announcement of intent to restructure the FutureGen project, DOE stated that the objectives of the revised approach are:

- Place emphasis on gaining early commercial experience validating clean coal technologies.....
- Provide the opportunity for international coordination ....
- Build upon current power market trends

In order to effectively meet these objectives, we believe it is essential that DOE expand the FutureGen program to include demonstration of a portfolio of promising CO2 capture technologies for combustion-based power. Continuing to restrict the FutureGen program to carbon capture for IGCC will have the unfortunate consequence of limiting innovation in CCS, thus increasing the risk and prolonging the timeline for successful deployment of CCS technology for the range of US coals and sites

Since the original decision of the FutureGen program to focus on IGCC technology, there have been significant developments in research in CO2 capture for combustion-based power including advanced amines, new solvents, oxycombustion and improved concepts for integration with the steam cycle. These technologies (both post combustion capture and oxycombustion), have the potential to meet and/or exceed the reliability, emissions performance, cost competitiveness and operational flexibility of IGCC with capture carbon. These developments have been recognized by a number of US and international organizations, including EPRI, the IEA, Canadian Clean Power Coalition and others, resulting in a steady expansion in lab and pilot scale testing of new capture technologies for combustion, and strong interest in the design of first of kind larger scale demonstrations by utilities and independent power producers. DOE's technical and project management skills would be highly beneficial to moving these technologies to commercial deployment.

It is also important to note that the Coal Utilization Research Council (CURC) has prepared a CCS technology roadmap, with input and consensus from a range of industry stakeholders. This roadmap defines both the content and timeline of RD&D needs to bring a portfolio of advanced coal technologies to commercialization. The CURC roadmap also endorses the need to expand beyond the original FutureGen IGCC technology platform to include both gasification and advanced combustion CCS technologies in programs to encourage early movers and first of kind commercial applications.

At the same time, there is growing recognition that the application of gasification to Western fuels and higher elevation sites will require further R&D to determine actual costs and performance capabilities. With the need to evaluate and prove basic gasification technology for Western fuels and to demonstrate reliability and cost of gasification on all fuels, it will be difficult if not impossible for the US to meet the goal of rapidly moving forward commercial options for carbon capture if technologies for combustion units are not included in the FutureGen program.

Expanding the FutureGen program to include capture technologies for combustion would also strongly support the goal of increased international coordination. Current market trends for new coal power generation are incorporating advanced coal combustion power plants utilizing supercritical and ultra supercritical steam cycles. High efficiency supercritical/ultra supercritical plants represent the majority of actual new capacity additions in the US and Europe, and are a rapidly increasing percentage of new coal plant orders in China, India, Australia, South Africa, and parts of Asia. By 2010, China alone will have almost 200,000 MW of new high efficiency supercritical combustion units in operation. These units present a viable base for the retrofit of CO2 capture, but the capture technologies must be demonstrated at commercial scale and need the benefits of cost reduction and performance improvements provided by a robust learning curve before they can be applied in competitive international markets. The US needs to lead this effort.

If the US is to provide leadership through international cooperation, CO2 capture technologies for combustion plants are a necessity. Projects to demonstrate post combustion capture and oxycombustion have recently been announced in the UK, Germany, Australia and Canada. Joint programs to demonstrate and deployment capture for combustion plants (similar to that executed for the previous FutureGen program) would likely be welcomed by the international community and would benefit the US and the world power industry.

Finally, although our comments today are focused on the technical requirements of the revised FutureGen program, we believe that the CCS program overall will require a significant commitment of funding beyond what has been applied to date. We encourage future DOE budgets to address expanded funding for CCS demonstration, commercialization and integration.

Recommendations for the modification of technical requirements as proposed for the restructured FutureGen program.

In parallel with the recommendation for expansion of the restructured program to incorporate advanced combustion technologies with CO2 capture and storage, it is important to review the technical specifications proposed in the RFI for applicability to the range of technologies.

Support for post combustion capture and oxycombustion technologies is well matched to the stated program goals of demonstrating 'the effectiveness, safety, monitoring and permanence of carbon sequestration (with the requirement of an annual 1 million metric tons for sufficient scale for storage monitoring and quantification), verification of commercially-accepted operability and reliability standards, producing the technical and economic data needed for these types of plants to gain acceptance, developing information necessary to estimate future costs of CO2 management and finally, ...

demonstrating the practical reality of CCS for coal-based power plants operated on different coals and at different US locations.' Advanced combustion with CCS is aligned with these goals, as well as the requirements specified for conventional emissions.

However, there are technical requirements that should be modified to incorporate the portfolio of technologies.

- Required size of demonstrations

  The RFI includes requirements on capture plant size, specifically, 'demonstrate approximately 90 percent CO2 capture and storage on one nominal 300 MW train ' which are not logical for application to advanced combustion units. IGCC projects are designed as 'trains', i.e., multiple modules of gasifiers and gas turbines, primarily due to the size limitations of commercially available gas turbines and current scale-up experience with gasifiers.

  However, advanced combustion plants do not have comparable equipment restrictions; units can (and have) been built as single 'trains' up to 1100 MW. On the other hand, CO2 capture processes for advanced combustion need to progress through a well-managed scale-up of modules (similar to the necessary scale-up for CCS on IGCC); it is expected that 200-300 MW would be the range of first commercial designs for post combustion capture. A requirement to build 90% first of kind CO2 capture into a new 800-1000 MW combustion unit would require multiple modules (trains) of post combustion capture technology... essentially having to duplicate the first of kind project multiple times on the same new power plant.... clearly an inefficient use of incentives, research $$, etc. In fact, the quantity of CO2 produced by high capture levels on a full 800 MW plant would likely exceed the scale of first of kind sequestration demos, making siting and integration of sequestration at this scale difficult.

  The logical corollary to 'CO2 capture and storage on one nominal 300 MW train for IGCC technology' would be to require combustion based technology to accomplish 'CO2 capture from a quantity of flue gas equivalent to 200-300 MW or to capture at least 1 million metric tons of CO2/yr'. The latter requirement (1MMT/yr) would ensure that the capture system provides sufficient scale of CO2 for storage demonstrations while allowing for a first of kind capture system at a technically reasonable scale. A capture 'train' on 200-300 MW of flue gas equivalent from an advanced combustion unit would allow evaluation of key design elements, liquid/gas contact surface designs, optimization of reaction kinetics, material and mechanical design improvements, etc. Following the demonstration, additional capture trains with next generation improvements can be added to the remaining flue gas to reach the goal of 90% total CO2 capture

  Ultimately, given the limitations of the CURRENT YEAR program budget, the objective of advancing storage technology may be better served by having more locations evaluated with less CO_2 injection, as long as the injection quantity is substantial (e.g., 500,000 TPY instead of 1,000,000). This option should be considered to increase the number of projects funded in order to broaden both technology and storage options to be evaluated. In subsequent fiscal year budgets, the DOE request should take into account the true scale of funding needs to accelerate this deployment and testing.

- Requirement for 90% CO2 capture.

  The stated requirement of 90% capture is clearly the commercial goal for all capture technologies applied to both combustion and gasification; it is expected that this goal will be reached as experience is gained with design and operation. However, it is more reasonable to expect performance of the first generation of commercial capture systems to be in the 65 –80% range for initial applications and to allow for improvements to the next generation to reach 90% capture. This development path is similar to industry experience with other environmental processes such as wet FGD.

As a practical matter, if the cost and or risk of implementing these first-of-a-kind systems greatly exceed the value of the incentive, industry will not build the units with CCS. This negates the purpose of having the incentive to gain near-term experience with these advanced technologies. In our discussions on CCS technologies with utility leaders, we have consistently heard from them of the importance of an improved CCS program to help address the need for both pilots/demonstrations as well as incentives for first of kind early adopters. The DOE role is important to reduce the risk premium that must be paid in ALL CCS technologies. It is important to find methods within this program to drive first generation technologies to commercial application, accepting that it may be too costly to optimise all aspects of performance until the technology is more mature. We must begin and learn by doing, rather than place initial performance hurdles so high that we discourage those with the courage to be the first movers of CCS technology.

Ultimately, the Revised FutureGen program success will be dependent on continued long-term dialogue and cooperation between DOE, utilities, technology suppliers, environmental organizations, regulatory bodies, and public stakeholders. We thank DOE for the opportunity to provide our comments.