COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

	)	
Application of Virginia Electric and Power	)	
Company for a Certificate of Public	)	
Convenience and Necessity to Construct and	)	**Case No. PUE-2007-00066**
Operate an Electric Generation Facility in Wise	)	
County, Va., and for Approval of a Rate	)	
Adjustment Clause Under Virginia Code	)	
§§ 56-585.1, 56-580 (D), and 56-46.1	)	

DIRECT TESTIMONY OF DOUGLAS H. CORTEZ
ON BEHALF OF
THE SOUTHERN ENVIRONMENTAL LAW CENTER
APPALACHIAN VOICES
THE CHESAPEAKE CLIMATE ACTION NETWORK
THE SIERRA CLUB
SOUTHERN APPALACHIAN MOUNTAIN STEWARDS

PUBLIC TESTIMONY
REDACTED VERSION

NOVEMBER 2, 2007

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1. INTRODUCTION

Q: Please state your name, current employment position and business address.

A: My name is Douglas Cortez. I am currently an independent energy consultant advising clients on all aspects of electric power plant planning, development, engineering, design and construction. My business address is Hensley Energy Consulting LLC, 412 North Coast Highway Suite B346, Laguna Beach, CA 92651.

Q. Please briefly describe your educational background and professional experience.

A. I received my BS in Chemical Engineering from University of California at Berkeley. I received my masters and doctorate in Chemical Engineering from the Massachusetts Institute of Technology. In February of 2006 I retired from Fluor Corporation (Fluor) after 36 years experience in the electric power, petroleum and petrochemical, and related energy industries in research and development, project development and financing, and engineering and construction capacities. My curriculum vitae is attached as Exhibit DHC-1.

I have testified as an independent expert in several power plant siting and environmental permit proceedings in the past two years. In most cases, I testified on the comparative merits of Integrated Gasification Combined Cycle (IGCC) and Supercritical Pulverized Coal (SCPC) technologies and related environmental and economic issues. As an independent technology consultant, I endeavor to present factual and objective information with the understanding that these are complex issues, and I take no position on the policies or regulations that should be adopted by the state or federal government.

Q: For whom are you testifying?

A: I am testifying for The Southern Environmental Law Center, Appalachian Voices, The Chesapeake Climate Action Network, The Sierra Club, and Southern Appalachian Mountain Stewards.

2. COMPARISON OF IGCC VERSUS CFB

Q: Can you describe Integrated Gasification Combined Cycle (IGCC) technology and comment on if carbon capture and sequestration technology is currently commercial available for IGCC?

A: IGCC technology can best be described as an environmentally superior process for generating power from coal. It accomplishes this by first converting coal to a clean burning fuel gas at high pressure in a gasification process. Gasification is the reaction of coal with steam in the absence of oxygen to produce "synthesis gas" or "syngas" which consists mostly of carbon monoxide and hydrogen. Pollutants in the coal, such as sulfur and nitrogen, are converted to acid gases and ammonia. Since the syngas is produced at high pressure (typically 500 to 1000 psi), the gas can be efficiently treated to remove virtually all of the impurities. The resultant "clean syngas" is burned in an efficient combined cycle plant which is integrated with the gasification step.

In addition to producing very low levels of regulated pollutants (i.e. SO_x, NO_x, particulates, mercury, VOCs), IGCC technology is uniquely suited to capture carbon dioxide (the major contributor to climate change and global warming). Since the clean syngas is produced at high pressure, it can be reacted with steam to shift the carbon monoxide to hydrogen and carbon dioxide. The CO_2 can then be removed and compressed for storage in underground geologic zones.

The technology for capturing carbon in an IGCC plant is proven technology that is practiced today on a large scale in commercial hydrogen, ammonia and other petrochemical plants.

Q. Does the technology exist today to capture carbon from a combustion power plant, such as a pulverized coal boiler or circulating fluid bed boiler?

A: The technology that is closest to being considered commercial is amine scrubbing technology. This technology has been used in the natural gas processing and refining industries to remove acid gases (hydrogen sulfide and carbon dioxide) from high pressure gas streams that do not contain excess air or oxygen. However, at this time, specialized amine scrubbing systems that process clean flue gas from natural-gas-fired boilers and power plants have been demonstrated on a small scale. The technology has not been demonstrated on a large scale on coal-fired power plants. The low-pressure flue gas would need to be compressed at high power cost for these absorbers to operate efficiently. In addition, the flue gas would require additional treatment to remove residual sulfur oxides prior to being fed to the CO_2 scrubbers. Although these steps have been demonstrated at a small scale, significant scale-up of these steps would be required before then technology could be classified as commercially proven, much less commercially available.

In a recent report from U.S. EPA[1], the contractor (Nexant) surveyed the current state of the amine scrubbing technologies for large-scale PC power plants. The study concluded, “While the amine process is technically proven in small-scale commercial operations, the economics and scale-up issues associated with a 500 Mw or larger power plant are substantial.” The EPA report also stated that, although the technology is being improved for natural gas applications, “...the development of similar systems for PC plants does not appear to be progressing

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[1] “Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technology,” EPA-430/R-06/006 (Jul. 2006) (“2006 EPA Report Comparing Gasification and PC Technologies”

very rapidly." Based on my review of the literature, it is my position that CO_2 scrubbing technology for SCPC plants carries significant cost and performance risk that can not be projected at this time. Only after large scale demonstration plants are operating, can these risks be fully understood. In contrast, the technology for capturing CO_2 in an IGCC plant has been demonstrated in large scale petrochemical plants and is ready for deployment if carbon controls are required.

Q. Will the carbon capture technology for pulverized coal plants be similar to that used for CFB plants?

A: I am not aware of any specific studies for adding carbon capture systems, such as amine scrubbing, to a CFB plant. However, since the flue gas stream to be treated will be similar I do not see any major differences. One difference might be the added costs of removing trace sulfur compounds from the flue gas. CFB boilers with post combustion dry lime scrubbers are likely to contain more residual SO_x than a PC plant with a wet limestone scrubber. Also, some developers of advanced amine scrubbing technology for PC coal boilers propose to integrate the scrubbing system with the coal boiler steam system to improve the energy efficiency of the total system. Similar integration features might be applied to a CFB plant. However, I am not aware of any published information on integrating CFBs with amine scrubbing systems.

Q: How would the emissions from the Dominion Virginia CFB Project compare with an IGCC Power Project?

A: Dominion has provided air emissions data in its PSD Permit. PSD permits have also been filed for several IGCC projects in recent years. Table 1 summarizes the key data for criteria pollutants. The data summarize the emission rates for criteria pollutants measured as normalized lb/MMBtu of fuel fed to the power plant. This method of measurement is commonly used to compare the environmental attributes of different technologies. (Note that in most cases, the emissions from start-up and shut-down periods and other ancillary sources are excluded. These other sources of emission are relatively small). The data show that an IGCC plant will produce dramatically lower emissions than the proposed CFB plant. As seen at the bottom of the table, the Dominion CFB project would produce 5 to 6 times the amount of CO, NO_x and VOCs when compared to the cleanest IGCC plant. It would produce about 17 times the SO_x and 30 times the particulate matter. When compared to the average performance of IGCC plants with permit applications, an IGCC plant will still have significant environmental advantages.

Table 1 also shows some data on mercury emissions. Based on the permit application for the Duke Edwardsport IGCC project, the Dominion CFB project would emit about 4 times as much mercury as an IGCC project. IGCC technology has the unique ability to capture essentially all of the mercury in coal fuels. The gasifer volatilizes the mercury which can then be trapped in sulfided carbon filters. Experience with mercury traps in the petrochemical industry shows that this method is extremely effective at removing mercury. Based on this experience, I would expect an IGCC with mercury traps to release even less mercury than the Duke permit application indicates.

Q: To what do you attribute the superior environmental performance of the IGCC technology over the CFB technology?

A: IGCC and CFB technology were developed for different applications. IGCC is best suited for higher Btu coals, including bituminous coal, sub-bituminous coals, heavy oils and petroleum coke. CFB technology is best suited for low Btu coals, such as coal waste and lignites. As currently practiced, CFB technology has some limitations on use of air pollution control technology that is proven for PC boiler power plants. In its PSD application, Dominion states that the following air pollution control technologies are not proven for CFB power plants: wet limestone scrubbing for SO_x reduction, selective catalytic reduction for NO_x reduction, and CO catalyst for carbon monoxide reduction. Although these technologies might be developed for CFB applications once certain technical improvements are developed, the cost would be prohibitive.

With IGCC technology, the systems used to reduce air emissions are each proven in IGCC and other commercial applications. More important, core systems can be engineered to improve environmental performance even after a plant is constructed. Retrofitting a CFB plant with wet limestone scrubbers, CO catalyst, and/or SCR units could be very expensive, provided the technology becomes available. Also, as illustrated below, the very large volumes of bottom and fly ash will create real challenges finding future markets for this waste material.

Q: How would the feed coal and ash disposal volumes for the Dominion Virginia CFB Project compare with an IGCC Power Project?

A: A typical bituminous coal IGCC project processes high btu, washed coal at a heat rate of about 8900 Btu/kw-hr. The IGCC plant requires no limestone and produces only a non-hazardous slag that may be sold or disposed in a land fill. To illustrate the broad solids handling dimensions, I have prepared Table 2.

Using the data provided by Dominion in its PSD application, the Southwest Virginia CFB project will produce about 14 times the volume of waste solids than a typical IGCC project. More important, the ash from a CFB plant is leachable and must be stored in managed landfills to prevent run off. An IGCC plant melts the ash in the coal and the slag product is non-hazardous. It may be sold as a construction material or stored in a less expensive land fill operation.

Table 2 also shows that the Southwest Virginia CFB project will also handle over twice the volume of solids to feed the plant (coal and limestone). The high volume of coal required to operate the CFB plant is due to its poorer efficiency and use of air cooling.

Table 1
AIR PERMIT EMISSION RATES FOR IGCC and Dominion CFB Units

Ref	Note	Power Project Name	Status	Coal Type	Technology	MMBtu/hr (Coal In) Plant MW (est'd)	lbs/MMBtu gasifier fuel energy input (approximate) CO	NOx	(SO)2	PM	VOC	lb/yr Hg
1	A	Wabash River	Operating, On-Line 1995	Illinois	E-Gas	2356 (262 Mw)	0.0360	0.0870	0.0800	0.0050	**0.0010**	
1		Polk Power Station	Operating, On-Line 1996	Eastern Bit	GE Energy	2191 (260 Mw)	0.0450	0.1010	0.1700	0.0080	**0.0010**	
1		Kentucky Pioneer	Permit Issued 2003	Eastern Bit	E-Gas	4413 (540 mw)	0.0260	0.0590	0.0260	0.0090	0.0040	
1		Lima Energy	Permit Issued 2003	Eastern Bit	E-Gas	4413 (540 mw)	0.0350	0.0670	0.0220	0.0080	0.0070	
1		We Energies - IGCC	Permit Issued 2004	Eastern Bit	GE Energy	5424 (550 Mw)	**0.0240**	0.0590	0.0230	0.0080	0.0030	
1		Steelhead Energy Center	Permit Filed 2004	Illinois	E-Gas	544 MW	0.0400	0.0590	0.0330	0.0092	0.0029	
1		Taylorville Energy Center	Permit Filed 2005	Illinois	GE Energy	677 MW	0.0360	0.0580	0.0450	0.0070	0.0080	
1	B	PMEC IGCC (Energy NW)	Permit Filed 2006	PRB	E-Gas	600 Mw	0.0360	**0.0120**	0.0160	**0.0010**	0.0030	
2		Mesaba I and II IGCC	Permit Filed 2006	PRB	E-Gas	600 Mw	0.0345	0.0570	0.0250	0.0090	0.0032	
		Mountaineer&MeigsCo IGCC	Permits Filed Sept 2006	Eastern Bit	GE Energy	629 Mw	0.0800	0.0500	**0.0070**	0.0075	0.0050	
4		Neuces IGCC Plant	Permit Filed 2007	PRB +Pet Coke	Dry Feed	600 Mw	0.0400	0.0190	0.0190	0.0140	0.0040	
5	C	Duke Edwardsport	Permit Filed 2006	Indiana	GE Energy	630 Mw	0.0440	0.0270	0.0140	0.0020	0.0020	16
		Lowest IGCC Emission Rate					0.0240	0.0120	0.0070	0.0010	0.0010	
		Average New Applications					0.0391	0.0489	0.0240	0.0081	0.0045	16
3		Dominion SWVa CFB	Permit Filed 2007	Unwashed Coal	CFB	580 Mw	0.1500	0.0700	0.1200	0.0300	0.0050	63
		Dom SW Va CFB X Average Permitted IGCC (Bolded)					3.84	1.43	5.00	3.71	1.12	3.94
		Dom SW Va CFB X Lowest Permitted IGCC (Bolded)					6.25	5.83	17.14	30.00	5.00	

Notes:
A SO2 adjusted to reflect published operating data
B Pacific Mountain Energy Center includes SCR for NOX Controls
C Excludes Startup/Shutdown, other intermittant. Steady State Operations

Ref:
1 Pacific Mountain Energy Center, Application for Site Certification Agreement Appendix B
Washington Energy Facility Site Evaluation Council, Application 2006-01, September 12, 2006
2 Mesaba Energy Project Mesaba I and II. June 16, 2006
Application to the Minnesota Pollution Control Agency for a NSR Construction Authorization Permit
3 PSD Application, Dominion Resources, Virginia Dept of Environmental Quality , August, 2007
4 Application for a TCEQ Flexible Air Quality Permit, Nueces County, Texas,Nueces Syngas LLC
5 PSD Application, Duke Indiana, Indiana Dept of Environmental Management, August 2006

Table 2 - Comparison of Solids Handling Volumes - CFB vs IGCC

Source		Dominion SW VA CFB PSD Application	IGCC Typical PJM Industry Reports
Plant Capacity	Mw	580	630
Coal Feed Rate	MMBtu/Hr	6,264	5,607
Coal Heating Value	Btu/lb	7,782	12,000
Plant Heat Rate	Btu (HHV)/kwhr	10,800	8,900
Plant Capacity Factor	%	90%	90%
Coal Use	tons/yr	3,173,052	1,841,900
Coal Use at 100% CF	coal at 100%	3,525,613	2,046,555
Coal Use at 100% CF	tons/yr	3,525,000	2,046,555
Limestone Use	limestone	350,000	-
Total Coal and LS	coal, limestone	3,875,000	2,046,555
Fly Ash Production	tons/yr	1,040,000	
Bed Ash Production	tons/yr	1,560,000	
Slag Production (10% ε	tons/yr		204,656
Total Ash to Disposal	tons/yr	2,600,000	
Total Slag Production	tons/yr		204,656
Ash Product Rate	tons/mwh	0.512	0.037
Coal/LS Use Rate	tons/mwh	0.763	0.371

3. LOWEST COST OPTIONS FOR NEW GENERATION

Q: Would a gas-fired facility be a lower cost option than Dominion's CFB proposal?

A: I have not specifically looked at a modern natural gas combined cycle option in comparison to Dominion's CFB project. In the past 2 years, the cost of power generation plants of all types has escalated dramatically as global competition for equipment, labor and construction services has exploded. From other reports I have seen, NGCC would be a lower cost resource when compared to a large SCPC plant based on today's price of natural gas.

Q: If Dominion proceeds with new coal generation capacity, is IGCC or SCPC a lesser cost resource compared to Dominion's CFB proposal?

A: Based on the documents Dominion provided, I was unable to see any information that addresses this question. In order to address it, I have completed a simplified comparison of the three coal options: IGCC, SCPC and CFB. The challenge in comparing technology options is finding consistent and current cost and performance data. So that my analysis is based on the most current cost information, I used the following information:

1. For IGCC, I started with the published information on the Duke Edwardsport IGCC project in Indiana. This information is available in the project PSD application and Indiana IURC filings.

2. For SCPC, I started with the published information on Duke's downsized *(i.e.,* one-unit) Cliffside project.

3. For CFB, I used the information provided by Dominion for the Wise County CFB project.

In the case of IGCC and SCPC, I relied upon a recent Department of Energy, National Energy Technology Laboratory (DOE NETL) report (Reference 4, Exhibit DHC-2), to estimate fixed and variable operating costs. For the CFB project, I used only information Dominion provided, [redacted] To insure a fair comparison, I applied the same factors the DOE NETL report used to the CFB project.

For fuel costs I used data from Dominion for the cost of unwashed coal in Wise County [redacted]. For SCPC and IGCC, I used the average cost of washed bituminous coal reported to FERC by utilities in the PJM region (about $2.35 / MMBtu).

To simplify the analysis, I used a levelized cost of capital based on Dominion's methodology and financing structure. For the CFB project, using Dominion's higher allowed return on equity, the levelized annual capital charge was estimated at 14.26%. For the IGCC and SCPC cases, I used Dominion's normal ROE. This reduced the annual capital charge to 12.66%. These are only rough approximations. However, I believe these assumptions capture the primary differences between the three technologies.

Q: In performing this simplified analysis, how did you address the issue of plant reliability, availability and capacity factor?

A: Dominion did not provide any basis for their assumption that the CFB plant would operate at 90% availability and capacity factor. There is little data available on availability of large CFB plants (over 500 Mw) in the public domain. The most recent, large CFB plant operating on waste coal is the Reliant project in Seward, Pennsylvania. Reliant reports the following information on their website[2]:

<u>Average Capacity Factor for 18 months ending June,2007</u>

All Reliant Coal Plants, excluding Seward	82.2%
Reliant Seward CFB Plant	72.5%

In examining the Reliant data, their 550 Mw CFB unit has rarely achieved the level of availability that the conventional coal units have achieved. Since Seward is operating on a very low cost waste coal, it seems unlikely that this low availability is due to economic dispatch. Therefore, for my analysis I used the Seward data for availability and also looked at the effect of higher operating reliability.

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2 http://www.reliant.com/PublicLinkAction.do?i_chronicle_id=0901752280002001&language_code=en_US&i_full_format=jsp

For IGCC and SCPC, I used 85% availability and capacity factor, assuming all plants are base loaded. This performance is representative of typical conventional PC coal plants according to the North American Electric Reliability Corporation (NERC) data. Commercial IGCC plants in Europe have also been operating at about the same level of reliability.

Q: How did the results of this analysis come out?

A: [redacted]

The COE for the IGCC and SCPC units are typical of what other studies have published, with the exception of the higher capital costs recently reported. Most studies report a 10 to 20% higher COE for IGCC. In this case, Table 3 reflects a higher premium for IGCC over SCPC due to the larger scale and economies of the 800 Mw SCPC unit.

[redacted]

[redacted]

These are preliminary data based on the information available to me. However, I believe the relative comparisons are meaningful, and the CFB project at this location appears to be a higher cost source of coal fired generation.

Q: Would the use of waste coal or biomass change this analysis?

A: Dominion did not provide any information that would allow me to examine the impact of waste coal or biomass. The Dominion filings state that the plant will be designed to feed up to about 20% of these materials. However, I could see no evidence that Dominion is required to use biomass or waste coal. Although these fuels are lower cost and may have some environmental advantages, it is unclear if they increase or decrease the cost of electricity when operating costs and reliability are factored in.

Q: How would this analysis change if Dominion were to add carbon capture equipment to the plant.

A: There have been many studies completed and more are underway on the costs of capturing carbon from conventional and IGCC power plants. In order to adjust the data presented in Table 3 for carbon capture, I developed the adjustment factors using several recently published independent studies. Table 4 below provides this information:

Table 4 - Changes for Carbon Capture (newly built)

Reference No. Exh B		1	2	3	4	5	
		US DOE / Parsons	US. DOE NETL	US. DOE NETL	MIT	IECM	Average
Technology	Parameter	2002 Bit	2006 Bit	2007 Bit	2006 NA	2005 Bit	various Bit Coal
IGCC	Increase in COE	37.9%	33.8%	34.6%	27.1%	48.9%	36.5%
PC Coal	Increase in COE	66.2%	68.0%	81.4%	60.9%	139.6%	83.2%
IGCC	$/kw investment	47.8%	32.8%	36.0%	32.2%	36.8%	37.1%
PC Coal	$/kw investment	73.3%	74.8%	82.2%	60.9%	53.6%	69.0%
IGCC	Increase in heat rate	16.6%	24.2%	20.8%	23.1%	16.1%	20.1%
PC Coal	Increase in heat rate	40.3%	43.1%	43.7%	31.9%	62.1%	44.2%

These studies were chosen because they examined both technologies with and without carbon capture on a consistent basis. Even though there were technology differences and time and cost differences, the results are remarkably in agreement. For my study, I used only the relative investment costs and heat rates to make the adjustments for carbon capture. All other assumptions remained the same.

There are no studies on adding carbon capture to a CFB plant. I would expect the costs to be similar, as the technical differences in flue gas properties are small.

Q: Using these guidelines, how did your study change when carbon capture is included.

A: Table 5 below shows the results of this exercise. The additional costs and performance penalties dramatically changes the projected cost of electricity. The IGCC option now becomes the least cost resource. The CFB option becomes the highest cost resource among the coal options. The very high CFB COE with carbon capture can be attributed to the high cost of adding CO_2 scrubbing and compression, the poor heat rate, and high fixed operating costs. Even at optimistic availabilities, a CFB unit with carbon capture is the most expensive power.

There are a number of assumptions in this study that should be clarified. The carbon capture data is based on applying amine scrubbing technology. This technology has not been applied to large scale coal plants but is believed by most experts to be the most advanced and commercially available technology for removing CO_2 from coal plant flue gases. There are other technologies that are under development that could reduce the cost of removing CO_2 from coal plant flue gases. The chilled ammonia and "oxy-fuels" technologies show credible promise for reducing the cost of carbon capture from PC boiler plants. However, those technologies are still in the research and demonstration phase and reliable data on performance and economics is not yet available.

The study is also based on "newly built" cost estimates. The cost of retrofitting existing coal plants could be more expensive. Significant engineering efforts are now underway to better understand and optimize the cost of retrofitting carbon capture to conventional coal or IGCC plants. However, I would not expect the relative costs between IGCC and conventional coal to change when the retrofit option is better defined.

[redacted]

Q: Is the proposed Dominion Wise County CFB Plant "carbon-capture compatible?"

A: According the documents Dominion provided, Dominion states the CFB project is carbon-capture compatible. They justify this statement on the fact that the plant plot plan contains space to add carbon capture equipment in the future. Other than identifying the plot space, Dominion provides no other information on this feature of the plant.

[redacted].

In order to be truly carbon capture compatible, it would be necessary to develop a conceptual design of the carbon capture and CO_2 compression equipment and prepare an equipment arrangement drawing. This would require selecting a technology basis for this operation. Such a study would determine the changes in the design of the CFB plant that might be required to accommodate future addition of carbon capture equipment. The most effective carbon capture process requires integrating the power plant steam system with the CO_2 scrubbing and stripping equipment. A phase one engineering study of the carbon capture system would identify the investments that would be needed to accommodate a future retrofit of the plant for carbon capture. Simply leaving plot area for a hypothetical carbon capture and compression plant does not make the plant carbon capture compatible.

In addition, the scope of work for the development phase did not appear to include any work effort that would be devoted to designing the plant for addition of future carbon capture equipment.

Based on my understanding of the term, I do not believe the current design of the Dominion CFB plant is carbon capture compatible.

4. NITROUS OXIDE EMISSIONS AND GLOBAL WARMING

Q: Is nitrous oxide a greenhouse gas pollutant? Is it more or less important than carbon dioxide?

A: Greenhouse Gases (GHG) have been identified by the U.S. Environmental Protection Agency (EPA) and the Intergovernmental Panel on Climate Change (IPCC). Both organizations have established Global Warming Potential (GWP) factors for GHGs [3]. The three gases that are produced in the largest volumes from combustion of fossil fuels are carbon dioxide (CO_2), methane, and nitrous oxide (N_2O). EPA reports that N_2O has a GWP factor of 310, which means that one pound of N_2O emissions is equivalent 310 lbs of CO_2 emissions.

Q: Compare N_2O emissions from IGCC to CFB.

A: It is widely understood that N_2O emissions from fluid bed boilers (bubbling and circulating) produce more N_2O than pulverized coal boilers. Formation of N_2O is favored at the lower temperature combustion conditions in a CFB. A PC boiler operates at much higher temperatures and nitrogen dioxide is formed at high temperatures. During the coal combustion process, fuel bound chemical nitrogen is a major source of nitrogen oxide gases, including NO_2 and N_2O. Nitrogen oxides are also formed from fixation of the nitrogen in the combustion air. Nitrous oxide is formed at low combustion temperatures. Because of the lower temperatures, a unique feature of a CFB is that the fuel bound nitrogen is likely the primary source of this climate change gas.

A principal advantage of a CFB is the lower amount of fixation of nitrogen due to its lower operating temperature. However, this condition creates a distinct problem for CFB technology in that the N_2O emissions are much higher.

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[3] http://www.epa.gov/nonco2/econ-inv/table.html

The gasification step in an IGCC plant operates at reducing conditions (absence of oxygen) under which no nitrogen oxides can be formed. All of the fuel bound nitrogen in the coal is converted to ammonia which is either sold as a chemical byproduct or converted back to harmless nitrogen. The combined cycle power block in an IGCC plant burns clean fuel gas with air. This process occurs at high temperatures at which no significant amount of N_2O is produced.

The 2006 IPCC Guidelines for National Greenhouse Gas Inventories provides data for estimating N_2O emissions from various coal combustion technologies[4]. Table 2.6 in the Guidelines (Utility Source Emission Factors) recommends using a emission factor for N_2O of 61 kg/TJ for circulating fluid bed boilers compared to 0.5 to 1.3 kg/TJ for PC boilers.

IPCC recommends, in Table 1.4[5] in the IPCC Guidelines, a default CO_2 emission factor for bituminous coal fired PC Boilers of 94,600 kg/TJ. Using these guidelines to estimate the impact of nitrous oxide emissions, the Dominion Southwest Virginia CFB project is estimated to produce N_2O emission equal to 310 times 61 or 18,910 kg/TJ of GHG equivalent CO_2 emissions. This suggests that the CFB project will produce about 20% more global warming gases than a similarly sized PC coal plant with the same heat rate. Since the CFB project operates on unwashed coal with air cooling, it's heat rate is 10,800 btu/kwhr (according to the Dominion PSD application) compared to about 8,900 btu/kwhr for a typical supercritical PC plant or IGCC plant operating on washed coal. So the Dominion CFB plant has a heat rate about 20% higher which means it processes 20% more coal fuel value to produce the same power as a SCPC plant. This suggests that the CO_2 emissions from the Dominion CFB project will produce about 20% more CO_2 gases per unit of power output. If the CFB plant produces N_2O at the rate estimated by the IPCC Guidelines, the total GHG emissions per unit of power output (CO_2 and N_2O measured as equivalent units of

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[4] http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_2_Ch2_Stationary_Combustion.pdf

[5] *Id.*

CO_2) could be about 46% higher than a bituminous coal-fired SCPC or IGCC plant.

Q: If N_2O, as a greenhouse gas, becomes a regulated pollutant, how does that impact the cost-effectiveness of CFB v. IGCC?

A: Although it is true that CO_2 and other GHGs such as N_2O are not currently regulated, such regulations are widely expected to be enacted soon and these regulations could have a large impact on the Dominion CFB project. PC Boiler and CFB projects that will operate for 30 to 50 years will likely be impacted by a tax on GHGs or a cap and trade system that requires offsetting GHG emissions or installing equipment to mitigate the emission of such gases. As discussed elsewhere in my testimony, the cost of capturing carbon from a SCPC or CFB plant will be much more expensive than an IGCC plant. Since N_2O is a recognized GHG by the EPA and the IPCC, a CFB plant like the one planned by Dominion will likely incur even higher costs to mitigate or offset N_2O emissions. In Dominion's PSD application, the company claims to leave space to add carbon capture equipment in the future. Dominion does not discuss N_2O emissions or if technology exists to mitigate N_2O emissions. [redacted]

Q: If N_2O becomes a regulated pollutant, is there technology available to reduce the N_2O emissions from CFB flue gas?

A: The limited amount of information I could find in the literature suggests that the CFB suppliers are aware of this problem and working on staged combustion and boiler modifications to reduce N_2O emissions. However, I was unable to confirm if this technology is effective, commercially proven, or available with warranties on the same terms NO_x and SO_x are guaranteed. Based on this limited information, I would be concerned that building a CFB plant would take on unknown risks of N_2O regulations and control technologies in the future.

Q: Does this conclude your testimony?

A: Yes.

EXHIBIT DHC-1

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Qualifications and Experience:

Dr. Douglas Cortez has over 35 years experience in the electric power, petroleum refining, chemical production, and synthetic fuels industries. During his career, he has focused on the clean fuels, clean power and alternative and synthetic fuels energy industries. He has held leadership positions in the fields of technology research and development, project development, project financing, and engineering and construction.

Hensley Energy Consulting LLC

In early 2006, he formed Hensley Energy Consulting LLC, an independent technology and management consulting company specializing in providing professional services to the clean energy and electric power industries and financial and government institutions. He is currently an advisor to the FutureGen Industrial Alliance, the Carson Hydrogen Power Project (BP Alternate Energy) and an advisor to Excelsior Energy (Mesaba IGCC). Other active clients include private equity funds, utilities, private developers of alternative energy projects and non-government organizations active in power plant siting proceedings.

Fluor Corporation

From 1984 to 2005, he was an executive with Fluor Corporation, the nation's largest publicly held engineering and construction company. At Fluor, he was Vice President, responsible for project development, project finance, and technology development serving a wide range of clients, including regulated utilities, independent power companies, coal mining, petroleum refining, and technology licensing companies. He contributed to the development and deployment of hundreds of power, cogeneration and clean coal and alternative energy projects, including coal, coke and heavy oil gasification projects, coal to liquids, substitute natural gas, integrated gasification combined cycle (IGCC) and coal to chemicals projects. His experience also includes carbon capture technologies for reducing the production of climate change gases.
In the power sector, he was active in developing, designing and financing a wide range of projects for regulated utility and independent power companies, including IGCC and conventional pulverized coal plants, complex refinery polygeneration plants, coal to chemicals and synthetic fuels facilities.

During his years with Fluor, he was active in technology evaluation, project development and finance in North America, Latin America, the Caribbean, Asia and Europe.

Tosco Corporation

From 1973 to 1983, he was an executive with Tosco Corporation (now part of ConocoPhillips). He was responsible for developing, financing and constructing cogeneration facilities at Tosco refineries and EOR fields, development of Tosco technologies for coal and petroleum coke utilization, development and licensing of Tosco's shale oil production, coal processing and petroleum refining related technologies. He was also a member of the management team that completed the acquisition of refining and marketing assets, as well as private and public oil and gas, coal and oil shale properties.

Other Experience

From 1969 to 1973, he was employed by an independent engineering consulting company that specialized in petroleum refining and geothermal energy production. During that period, he developed and constructed geothermal power plants, and petroleum refinery projects. He also consulted with the Plan Organization in Iran and developed the 10 year expansion plan for the NIOC refining and products distribution system.

Employment History:

2006- Present	Managing Partner, Hensley Energy Consulting, LLC
1984 - 2005	Vice President, Fluor Enterprises
1973 - 1984	General Manager, Tosco Corporation
1970 – 1973	Project Manager, Ben Holt Company
1969 – 1970	Research Engineer, TRW Systems

Education:

ScD	Chemical Engineering, Massachusetts Institute of Technology
MS	Chemical Engineering, Massachusetts Institute of Technology
BS	Chemical Engineering, University of California, Berkeley

Industry Participation:

American Institute of Chemical Engineers
Gasification Technologies Council (Industry Representative, Workshop Speaker, Communications Committee)
Coal Utilization Research Council (Industry Representative)
FutureGen Industrial Alliance – Technical Advisory Committee

Recent Expert Testimony:

The following testimony addressed only technology and economic issues in coal power plant cases where gasification combined cycle technology is being considered. HEC does not advocate a public utility policy position.

1. On behalf of Wisconsin Energy, Public Service Commission of Wisconsin Docket No. 05-CE-130.
2. On behalf of Wisconsin Energy, Wisconsin Electric Power Permit 03-RV-166, Case No.IH-04-03, Wisconsin Division of Hearings and Appeals.
3. On behalf of Excelsior Energy, Minnesota Office of Administrative Hearings for the Minnesota Public Utilities Commission, MPUC Docket No. E-6472-/M-05-1993, OAH Docket No. 12-2500-17260-2. (Phase 1 -2006)
4. On behalf of Environmental Defense, Southern Environmental Law Center, and Southern Alliance for Clean Energy, in the matter of Duke Power Co. LLC for approval of an Electric Generation CPCN to construct two 800 Mw Coal Units for Cliffside Project, North Carolina Utilities Commission, Docket No. E-7, Sub. 790

5. On behalf of Clean Air Task Force And Indiana Wildlife Federation, in the matter of the Duke Energy Indiana for approval of Edwardsport IGCC project, before the Indiana Utility Regulatory Commission, Cause No. 43114.
6. On behalf of Environmental Defense, in the matter of Applications of TXU Generation Co. LP for State Air Quality Permits and PSD Permits, before the Texas State Office of Administrative Hearings, SOAH Docket No. 582-07-0614.
7. On behalf of Excelsior Energy, Minnesota Office of Administrative Hearings for the Minnesota Public Utilities Commission, OAH Docket No. 4-2500-17260-2, MPUC Docket No. E-6472/M-05-1993, In the Matter of a Petition by Excelsior Inc. for Approval of a Power Purchase Agreement under Minn. Stat. § 216B.1694, Determination of Least Cost Technology and Establishment of a Clean Energy Technology Minimum Under Minn. Stat. § 216B.1693. (Exhibit DHC1, Phase 2 – 2007)

EXHIBIT DHC-2

List of Referenced Reports

Studies of SCPC and IGCC with and without Carbon Capture

1. Parsons Energy and Chemicals, on behalf of U.S. Dep't of Energy, Nat'l Energy Tech. Lab., "Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal," (2002) (*as reported in* Reference 9).
2. J. Klara, U.S. Dept. of Energy, Nat'l Energy Tech. Lab., "IGCC: Coal's Pathway to the Future," Gasification Tech. Council Annual Meeting, Washington D.C. (Oct. 2-4, 2006).
3. U.S. Department of Energy National Energy Technology Laboratory, Cost and Performance Baseline for Fossil Energy Plants, DOE/NETL-2007/1281, Volume 1: Bituminous Coal and Natural Gas to Electricity, Final Report, May 2007, available at http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf.
4. Massachusetts Institute of Technology, The Future of Coal: Options for a Carbon-Constrained World, March 2007, available at http://web.mit.edu/coal/The_Future_of_Coal.pdf.
5. Integrated Environmental Control Model (IECM) US DOE/NETL and Carnegie Mellon. Website: http://www.iecm-online.com/