Report Comparing Alternative Technologies for
The Virginia City Hybrid Energy Center

Prepared for
National Parks Conservation Association
1300 19th Street NW, Suite 300
Washington, DC 20036

In the matter of the Application of Virginia Electric and Power Company for a PSD Air Permit before the Virginia Department of Air Quality

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1. INTRODUCTION

National Parks Conservation Association (“NPCA”) retained Hensley Energy Consulting, LLC (“HEC”) to prepare this report in connection with the application by Virginia Electric and Power Co. (“VEPCO”) for a PSD air permit for the proposed Virginia City Hybrid Energy Center (“VCHEC”). HEC is an independent technology consulting firm specializing in clean power and energy technology. Its managing director, Dr. Douglas H. Cortez has over 35 years experience with a wide range of coal and petroleum processing technologies. Dr. Cortez’s curriculum vita is attached as Exhibit DHC-1.

The report addresses the primary alternative technologies available to VEPCO for generating power from coal, principally Circulating Fluid Bed (“CFB”) technology, Supercritical Pulverized Coal (“SCPC”) technology, and Integrated Gasification Combined Cycle Technology (“IGCC”). The primary focus of this report is environmental performance, including climate change or greenhouse gas (“GHG”) emissions. Other features of the technologies including fuel flexibility, water consumptions, solid waste, reliability and maturity of the technologies is discussed.

HEC is a technology consulting firm that relies upon publicly available information and the private experience of its managing director. Information and references cited in this report are from public sources and no third party confidential information available to HEC is disclosed. HEC believes the information presented in this report is from reliable sources but HEC cannot guarantee the accuracy of the information. HEC does not advocate any particular technology or project as such advocacy requires considering many important factors that are beyond the scope of this report.

2. COMPARISON OF IGCC, CFB and SCPC TECHNOLOGIES

Integrated Gasification Combined Cycle (IGCC)
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\textsubscript{x}, NO\textsubscript{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 chemically shift the carbon monoxide to hydrogen and carbon dioxide. The CO\textsubscript{2} can then be removed (“captured”) and compressed for storage in underground geologic zones or used for enhanced oil recovery.

The technology for shifting synthesis gas to hydrogen and for capturing carbon dioxide in an IGCC plant is proven technology that is practiced today on a large scale in commercial hydrogen, ammonia and other petrochemical plants. A few IGCC plants operating in Europe today are capturing a portion of the carbon dioxide although none are sequestering the CO\textsubscript{2}.

**Supercritical Pulverized Coal (SCPC)**

A supercritical pulverized coal (SCPC) power plant generates steam from pulverized coal in a conventional boiler and the steam is passed through a steam turbine generator set to generate electricity. SCPC plants achieve higher conversion efficiencies by generating steam at “supercritical” pressures. Under current definitions of BACT, recently constructed SCPC plant employ a wide range of pollution control equipment, including baghouses and precipitators to remove
particulate matter, selective catalytic reduction (SCR) to remove NOx, and wet limestone scrubbers to remove sulfur oxides. Over 25 SCPC plants have been constructed and are operating in the US today however not all of these plants include the full suite of environmental control technologies.

**Circulating Fluid Bed Boiler**

A circulating fluid bed boiler (CFB) power plant generates steam from pulverized coal in “fluid bed” into which limestone is injected to capture sulfur at lower combustion temperatures which also reduces the formation of NOx compounds. CFB boilers collect and recycle large quantities of ash to increase carbon burnout and increase plant efficiency. The nature of the combustion process in a CFB requires larger equipment with more solids handling than a conventional pulverized coal boiler which combusts the coal at higher temperatures in smaller volumes. Wet limestone scrubbing and SCR are not considered feasible for use with CFB technology today. In order to improve the SOx removal efficiency of CFB units processing high sulfur coals, dry lime scrubbing units have been added to some recently constructed CFB units. Selective Non-catalytic Reduction (“SNCR”) is available to reduce NOx downstream of a CFB boiler. Similarly, catalytic reduction of carbon monoxide is not considered proven for CFB technology. The first CFB units were developed for smaller scale power generation applications (up to 100 Mw) and for burning high ash coals, coal waste, biomass and other lower grade solid fuels. In recent years, single CFB boilers as large as 250 Mw net have been constructed. CFB technology operating with super-critical steam conditions is not commercially available although super-critical CFB technology is under development. The proposed VCHEC CFB project is based on the largest available CFB technology (almost 300 Mw gross) with SNCR and dry lime scrubbing technology.
3. CARBON CAPTURE CAPABILITIES OF IGCC, CFB and SCPC TECHNOLOGIES

Post-combustion carbon capture technology (carbon dioxide removal) for SCPC and CFB technology is still under development. 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, 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 for 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 CO₂ scrubbers. Although these steps have been demonstrated at a small scale, significant scale-up of these steps would be required before the technology could be classified as commercially proven, much less commercially available.

In a recent report from U.S. EPA¹, 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 very rapidly.” Based on a review of the public literature, there is a consensus that CO₂ scrubbing technology for SCPC plants carries significant cost penalties and performance risk that cannot be

projected at this time. Only after large scale demonstration plants are operating, can these risks be fully understood. Although a large coal IGCC plant with full carbon capture has not been constructed, numerous public and private studies have investigated the IGCC carbon capture option. There is a consensus in the literature that the technology for capturing CO₂ in an IGCC plant has been demonstrated in large scale petrochemical plants and is ready for deployment. The aforementioned EPA report stated: “The processes required to remove CO₂ from an IGCC plant are commercial in other gasification applications.”¹

We are unaware of any reported study examining the application of post-combustion carbon capture technology to a CFB plant. However, since the flue gas stream to be treated will be similar to a SCPC plant, we do not see any major differences. 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, having reviewed the literature, we are not aware of any published information on integrating CFBs with amine scrubbing systems.

4. COMPARISON OF VCHEC EMISSIONS AND TYPICAL SCPC and IGCC PLANTS.

VEPCO has provided air emissions data in its PSD Permit. PSD permits have also been filed or issued for several large SCPC power plants in recent years. We have reviewed seven of the most recent SCPC plants that burn bituminous coals with medium to high sulfur content. (SCPC projects using low sulfur sub-bituminous coals are governed by different, but similar, set of BACT standards). Exhibit DC-2 summarizes the BACT determinations for these seven SCPC plants. EPA BACT methodology applies emission rates expressed in pounds of each criteria pollutant per
Comparing Alternative Technologies for The Virginia City Hybrid Energy Center

MMBtu of fuel fired to the boiler or combustion device. Since this report is addressing the relative environmental performance of SCPC, CFB and IGCC as power generation technologies, we have converted the BACT data in for each power plant to pounds of pollutant per useful unit of energy produced for sale, or net kilowatt-hours. Those data are also shown in Exhibit DC-2.

Figure 1 below shows graphically how the VEPCO CFB project compares to the seven SCPC plants listed in Exhibit DC-2.

VEPCO represents that the Hybrid Energy Center is a “clean coal” project. Figure 1 suggests that this may not be the case. With the exception of particulate matter, these data show that the VCHEC CFB project will produce substantially more pollution. Compared to the “best in class” SCPC projects, VCHEC will produce 7 to 10 times more SO2, and 50% to 150% more CO, VOC and mercury emissions. NOx emissions will be slightly higher than the SCPC that have been permitted.

PSD permits have also been filed or issued for ten IGCC projects in recent years. Exhibit DC-3 summarizes the key data for criteria pollutants for those projects.
The data summarize the emission rates for criteria pollutants measured as normalized lb/MMBtu of fuel fed to the power plant. As with the SCPC data, we have estimated the same emission rates expressed in pounds per kwhr of useful power produced. (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). Exhibit DC-3 also shows data for the two IGCC demonstration plants operating in the U.S.

The table in Exhibit DC-3 summarizes the median and minimum BACT determined rates for these IGCC projects. We have excluded the Wabash and Polk data from this analysis. Although these plants have emission rates generally below most PC coal plants, we believe it is a mistake to use these data to represent the state of the art IGCC technology. It would likewise be a mistake to compare the most recent SCPC data using the emission data from plants constructed 15 to 25 years ago. The Wabash and Polk IGCC plants were permitted in the early 1990’s under different BACT rules and regulations. Therefore the most recent PSD permits represent the collective determination of permitting agencies and the technology suppliers of current emissions performance capabilities of IGCC and SCPC technology.

The data show that an IGCC plant will produce dramatically lower emissions than the proposed VCHEC CFB plant or a modern SCPC power plant. Figure 2 below shows graphically how the VCHEC CFB project compares to the ten IGCC plants. Since the differences are so large, we have plotted the ratio of VCEHC emissions to the median and minimum (“best in class”) emission rates for the IGCC plants using a logarithmic scale.
The chart shows that compared to the best in class IGCC technology, the VEPCO CFB project will produce 5 to almost 15 times as much mercury, CO, NOx, PM and VOC emissions. These data show that IGCC, as evaluated by ten State EPA’s will be the cleanest coal technology by a wide margin.

IGCC technology has the potential to achieve even better environmental performance. BACT methodology sets the emission rate after considering actual experience with the method of controlling each emission and the economics of achieving lower emissions. IGCC technology approved in the permits listed in Exhibit DC-3 is based on these conservative standards and the guarantees available from technology and equipment suppliers. Based on the practices of the refining and petrochemical industry, the gas processing technologies employed in a modern IGCC plant can be designed to achieve lower emissions. For example, in petrochemical plants where mercury traps have been used for years, the mercury in the clean product gas is virtually undetectable. Based on this experience, we would expect an IGCC
with mercury traps to release even less mercury than the best in class data in Figure 2 and Exhibit DC-3. Commercial gas cleaning technology also exists that could reduce SO2 emissions to near zero levels. However, the added cost of using this technology is not considered justified under today’s BACT methodology.

The superior performance of IGCC technology over SCPC and CFB can be attributed to several factors. IGCC and CFB technology were developed for different applications. IGCC is best suited for higher Btu, lower ash coals, including bituminous coal, sub-bituminous coals, heavy oils and petroleum coke. An IGCC plant is very efficient at removing sulfur, so coal with any sulfur content can be easily processed in an IGCC plant. As discussed in Section 8, low ash bituminous coals appear to be available in Southwest Virginia. CFB technology is best suited for low Btu, very high ash coals, such as coal waste and lignites. With very high sulfur content coals, a CFB will produce higher SO2 emissions. 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, VEPCO states that the following air pollution control technologies are not proven for CFB power plants: wet limestone scrubbing for SOx reduction, selective catalytic reduction for NOx reduction, and CO catalyst for carbon monoxide reduction. The inferior environmental performance of CFB technology is illustrated in summary of BACT determinations in Figures 1 and 2.

With IGCC technology, the systems used to reduce air emissions are each proven in IGCC and other commercial applications. More important, core IGCC subsystems 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.
5. COMPARISON OF SOLID WASTE PRODUCTION FROM VCHEC AND TYPICAL IGCC PLANTS.

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 landfill. To illustrate the broad solids handling dimensions, we have prepared Table 1.

Using the data provided by VEPCO in its PSD application, the VCHEC CFB project will produce about 14 times the volume of waste solids (per Mw-hr of useful product) 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 all of 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 landfill operation.

Table 1 also shows that the VCHEC 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, the use of high ash coal fuel, and use of air cooling. If low ash coal from the region were used, these volumes of coal transportation and ash handling would be reduced significantly. With IGCC technology, the amount of solid fuels and waste handling would be the lowest.
Table 1 - Comparison of Solids Handling Volumes - CFB vs IGCC

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

6. LOWEST COST OPTIONS FOR NEW COAL POWER GENERATION

Relative Cost of Electricity without Carbon Capture

Based on confidential information we received pursuant to the Virginia State Corporations Commission hearings, and recent estimates for SCPC and IGCC projects in the region, we prepared estimates of the cost of electricity (COE) from the VCHEC CFB project and a standard IGCC (630 Mw) and SCPC (800 Mw) power plant. The rated capacity of a “standard” IGCC is approximate 630 Mw and fixed by the use of currently available state-of-the-art combustion turbines (Frame 7 class). The largest single boiler SCPC plant available today, with a single steam turbine, is approximately 800 Mw. Similarly, the VCHEC is based on using two of the largest
CFB boilers available today. The details of our study are confidential under SCC rules of confidentiality. However, our analysis indicated that the COE from the VEPCO CFB project will be meaningfully higher than an 800 Mw SCPC plant burning high BTU bituminous coal. When compared to a 630 Mw standard IGCC plant, the COE of the VCHEC is estimated to be about the same. From this study, it would not appear that the VCHEC CFB project is the least cost resource. Further information on this analysis is available in our non-confidential testimony before the VA SCC. ²

**Relative Cost of Electricity with Carbon Capture**

When the impact of carbon capture equipment is included, the relative cost of electricity from SCPC, CFB and IGCC power plants changes dramatically. 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 address this question, we developed the adjustment factors using several recently published independent studies. Table 2 below provides a summary this information:

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² On behalf of the Southern Environmental Law Center, in the matter of the Application of Virginia Electric and Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate an Electric Generation Facility in Wise County, VA, before the Virginia State Corporation Commission, Case No. PUE-2007-00066
Table 2 - Changes for Carbon Capture (newly built)

<table>
<thead>
<tr>
<th>Reference No. Exhibit DC-4</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Technology</td>
<td>Parameter</td>
<td>2002 Bit</td>
<td>2006 Bit</td>
<td>2007 Bit</td>
<td>2006 Bit</td>
<td>2005 Bit</td>
</tr>
<tr>
<td>IGCC</td>
<td>Increase in COE</td>
<td>37.9%</td>
<td>33.8%</td>
<td>34.6%</td>
<td>27.1%</td>
<td>48.9%</td>
</tr>
<tr>
<td>PC Coal</td>
<td>Increase in COE</td>
<td>66.2%</td>
<td>68.0%</td>
<td>81.4%</td>
<td>60.9%</td>
<td>139.6%</td>
</tr>
<tr>
<td>IGCC</td>
<td>$/kw investment</td>
<td>47.8%</td>
<td>32.8%</td>
<td>36.0%</td>
<td>32.2%</td>
<td>36.8%</td>
</tr>
<tr>
<td>PC Coal</td>
<td>$/kw investment</td>
<td>73.3%</td>
<td>74.8%</td>
<td>82.2%</td>
<td>60.9%</td>
<td>53.6%</td>
</tr>
<tr>
<td>IGCC</td>
<td>Increase in heat rate</td>
<td>16.6%</td>
<td>24.2%</td>
<td>20.8%</td>
<td>23.1%</td>
<td>16.1%</td>
</tr>
<tr>
<td>PC Coal</td>
<td>Increase in heat rate</td>
<td>40.3%</td>
<td>43.1%</td>
<td>43.7%</td>
<td>31.9%</td>
<td>62.1%</td>
</tr>
</tbody>
</table>

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 the study of the VCHEC plant, we 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 that we are aware of on adding carbon capture to a CFB plant. However, we would expect the costs to be similar, as the technical differences in flue gas properties are small. Since the VCHEC CFB releases more CO₂ than a SCPC plant, the cost of carbon capture will likely be higher. For our study, we ignored this fact. Thus, our estimates are likely to understate the VCHEC costs of carbon capture.

The additional costs and performance penalties dramatically changes the projected cost of electricity. The details of our study are confidential under the SCC rules of confidentiality. However, our study shows that the IGCC option with carbon capture is projected to be the least cost resource. This result is consistent with the other studies that have been reported. The VCHEC CFB option becomes the highest cost resource among the three coal technology options. The significantly higher COE for VCHEC project with carbon capture is attributable to several factors, including
the high cost of adding CO₂ scrubbing and compression, the facility’s poor heat rate, higher fixed operating costs and higher regulated return on shareholder equity requested by VEPCO.

There are a number of assumptions in our study that should be noted. 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 CO₂ from coal plant flue gases. There are other technologies that are under development that could reduce the cost of removing CO₂ 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.

Our 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 and IGCC plants. However, we would not expect the relative costs between IGCC and conventional coal to change when the retrofit option is better defined.

VEPCO claims that the VCHEC is designed to be “carbon capture compatible”. The company justifies 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, VEPCO provides no other information on this feature of the plant.

In order to be truly carbon capture compatible, it would be necessary to develop a conceptual design of the carbon capture and CO₂ 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 CO₂ 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. Based on my understanding of the term, we do not believe the current design of the VEPCO CFB plant is carbon capture compatible.

7. RELIABILITY OF SCPC, IGCC AND CFB TECHNOLOGIES

A major consideration in selecting a coal fired power generation technology is its long term reliability. Plant operating factors have a major impact on the cost of services for these capital intensive projects.

SCPC technology is a proven power generation technology. The North American Electric Reliability Council ("NERC") reports on actual coal boiler plant availabilities using several defined terms for availability. One of the common measures of availability is Equivalent Availability Factor ("EAF") which measures the availability of the power plant after accounting for planned and unplanned outages including deratings due to partial outages. NERC reports the following EAF data for large coal power plants over 1000 MW:

<table>
<thead>
<tr>
<th>Time Period</th>
<th>EAF</th>
</tr>
</thead>
<tbody>
<tr>
<td>1982-2005</td>
<td>79.7%</td>
</tr>
<tr>
<td>1996-2005</td>
<td>81.9%</td>
</tr>
<tr>
<td>2001-2005</td>
<td>81.7%</td>
</tr>
</tbody>
</table>

The NERC data includes sub- and super-critical PC boiler plants with and without scrubbers, SCR and other contemporary environmental control equipment.

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3 See North American Reliability Council website: http://www.nerc.com/~gads/
The NERC data contains details for each type of boiler but this data is not available to the public. From the publicly available NERC data, we conclude that large coal PC plants average availability is in the 80% to 82% range.

In VEPCO’s SCC filings, the company assumes 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:\(^4\):

**Average Capacity Factor for 18 months ending June, 2007**

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

These data suggest that Reliant’s convention coal power plants have operating histories similar to the NERC averages. However, the data also show that their 550 Mw CFB unit has rarely achieved the level of availability that the conventional coal units have achieved. Since Seward is operating on only low cost waste coal, it seems unlikely that this low capacity factor is due to economic dispatch or curtailment. NERC most likely has individual power plant availability data, including CFB units. However, this data is not available to the public. Based on this limited amount of data, we would expect a very large CFB plant to perform no better than a SCPC power plant and possible with lower levels of reliability.

Reliability of newly designed IGCC plants is more difficult to determine. Critics of IGCC technology point to the performance of the Wabash and Polk IGCC

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demonstration plants as examples of reliability problems with IGCC technology. The operating history of these plants has been reported in detail in numerous DOE reports ending in about 2002-2003. Those reports explain in detail the sources of outages in the two demonstration plants. Although key components of the gasification sections of each IGCC plant had early problems with equipment design and performance, those problems have largely been addressed. Many of the outages of the Wabash and Polk plants were attributed to problems with conventional equipment outside of the gasification technology. For example, both plants have had ongoing problems with the air separation units and the combined cycle power units. Since 2002, there has been very little information available on the two US IGCC demonstration plants. The Wabash IGCC plant was acquired by Wabash Valley Power Cooperative two years ago. Recently, Wabash also acquired the combined cycle plant which is a major cause of plant outages. We understand that since the combined cycle unit has been acquired and the entire plant has been operating as an integrated IGCC unit, that the performance has been outstanding. However, this detailed operating data is confidential. It can be made available to power companies that sign non-disclosure agreements and express a serious interest in IGCC technology.

Although they are designed to operate on asphalt, the large Italian IGCC projects demonstrate that complex, integrated, multiple train, IGCC plants can be operated reliably. A recent report by Foster Wheeler has provided availability data for these projects. Foster Wheeler reports that the ISAB IGCC plant has achieved “excellent” results from the first year of commercial operations. Excluding the time the turbines operated on fuel oil, the facility achieved the following annual availabilities (i.e. syngas fuel only operations) during 2003 to 2005 of 86.5% to 96.3%. Foster Wheeler reports even better performance for the API Energia IGCC project. This plant achieved annual availability of 90% to 94% between 2004 and 2006.

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5 “IGCC Technologies: FWI Capabilities and Experience” Rosa M. Domenichini, Presentation to Great Plains Institute, October 8, 2007.
It is important to note that a significant investment in engineering of IGCC plants has been made in the past 2 to 4 years. Much of this information is not available to the public. Duke Energy, American Electric Power and other utilities have invested in the design, engineering and development of IGCC projects. Of relevance to the VEPCO VCHEC project is the efforts of Appalachian Power (AEP) to construct an IGCC in nearby West Virginia. Testimony of AEP Senior Vice President Michael Rencheck explained why AEP has selected IGCC technology for its long term reliable base load coal plant in West Virginia. Some of Mr. Recheck’s testimony is summarized below:6

“We recognize that the IGCC technology has advantages, both environmental and economic, especially under potential C02 control scenarios, making it the logical choice for new baseload generation at the Mountaineer site. An IGCC plant using the newest, cleanest technology will initially cost more than conventional pulverized coal units, but we project that it will be the least-expensive option over the life of the plant. It's a decision for long-term success in an environmentally constrained world.”

“We conclude that deploying the IGCC technology on a commercial scale is both fiscally responsible and the right thing to do as a matter of public policy for AEP, for APCo, and for the States of Virginia and West Virginia.”

“At this time, there are no known commercial scale applications for carbon capture for a pulverized coal plant. When IGCC's environmental benefits are compared to that of conventional pulverized coal, IGCC clearly comes out ahead.”

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6 Direct testimony of Michael W. Rencheck, On behalf of Appalachian Power Company before the Virginia SCC. Application of Appalachian Power Company For a Rate Adjustment Clause Pursuant to §56-585.1 A 6 of the Code of Virginia, Case No. PUE-2007-00068
These and other statements by AEP and APC in their testimony before the VA SCC are consistent with the studies and reports that we have cited and other statements in this report.

8. COAL QUALITY AND FUEL FLEXIBILITY

Both IGCC and CFB technologies are often described as “fuel flexible”. VEPCO has stated that the VCHEC plant is fuel flexible.

IGCC technology can be designed to operate on a wide range of feed materials. As examples, the Wabash IGCC plant has operated on a range of 100% bituminous coals and 100% petroleum coke, the Mesaba IGCC project is designed to operate on a range of western sub-bituminous coals, Illinois bituminous coals and petroleum coke, and the Shell IGCC plant in Buggenum, Netherlands, operates on a range of imported coals and significant amounts of biomass. The predecessor to the Wabash IGCC facility, the Dow Chemical Placquemine LA IGCC plant processed over 1 million tons of sub-bituminous coal successfully. Dry feed commercial gasifiers, such as those offered by Shell, MHI, and Siemens, are all capable of processing low btu, high ash coals, wastes, biomass, and other difficult fuels. The Dakota Gasification plant in North Dakota has been processing high ash lignite for many years with great success. Don Shepherd with the National Park Service described these capabilities in his presentation to the Virginia Department of Environmental Quality.7 Notwithstanding the technical ability of IGCC technology to handle a wide range of solid fuels, a fuel flexible IGCC plant requires specific design features that add to the cost of the facility. At the same time, a CFB power plant also requires added design features to process a wide range of solid fuels.

CFB technology is best suited for low value, high ash waste coals and biomass. The VCHEC plant is designed to operate primarily on high ash “run of mine” ("ROM") or unwashed coal (approximately 7780 Btu/lb, 44% ash). Although a CFB plant can be designed to run 100% waste coal, biomass or high ash coal, the plant must be designed for that purpose. The design of such a plant would add to the cost of the boiler, air pollution control equipment, utilities, off-sites and infrastructure. According to documents filed with the Virginia State Corporations Commission, VECPO has designed the VCHEC to burn up to 20% coal waste or up to 20% biomass or waste wood in blends with ROM coal. The VCHEC could be designed to process 50% or 100% very high ash coal waste, but VEPCO has chosen not to pay the premium in capital and operating costs to process more significant quantities of this waste material. Also, there appears to be no legal or regulatory requirement for VEPCO to process any coal waste or biomass. In addition, the proposed permit conditions limit the sulfur content of the coal fuels or blends. Therefore, it appears that the VCHEC could not be appropriately called a “fuel flexible” power plant and the statements made in the aforementioned Dominion letter to the DEQ do not appear to be supported by the facts.

VEPCO has not provided any information that would allow us to examine the impact of waste coal or biomass on environmental performance. VEPCO’s PSD permit application states that processing ROM coal or blends of this coal with waste coal or biomass will meet the permit conditions limiting short term and annual emissions of criteria pollutants. VEPCO also states that if these conditions can not be met they will offset the higher emissions by purchasing offsets or shutting down other emission sources.

Based on similar CFB projects, we would expect the plant efficiency to decline when waste coal is blended with higher quality coal. If the waste coal is lower in sulfur content, the plant should be able to meet emissions limitations and BACT standards. However, the plant will produce more GHGs per kilowatt hour of output when burning coal waste. We would expect emissions of most criteria pollutants and GHGs to improve when burning small amounts of biomass blended with coal.
9. VIRGINIA COAL SUPPLY

VEPCO has stated in documents filed with the Virginia State Corporations Commission that the VCHEC uses CFB technology because there are limited supplies of low ash ROM coal or washed coal in Southwest Virginia and that Virginia’s electric restructuring statutes require the use of ROM high ash coal and coal waste. VEPCO reinforced this position in a February 19, 2008 letter from Dominion to the Virginia DEQ\(^8\), which states:

“......Va. Code § 56.585.1.A.6, finds such use of Virginia coal to be in the public interest. Thus consideration of alternatives to Virginia coal would be contrary to the General Assembly’s clear intent. That leaves the question of fuel cleaning or coal washing. Such an alternative is also at odds with one of the goals of the project -- to consume waste coal so it does not pose an environmental risk. Waste coal is produced by fuel cleaning and preparation. It would be irrational to produce waste coal by fuel cleaning and then clean the waste coal. Moreover, there are no alternatives to CFB for burning waste coal. It would also be irrational to shun CFB technology that can eliminate the environmental risk of waste coal in favor of IGCC technology that would require greater amounts of coal washing resulting in still greater waste coal and its attendant risks.”

If one of the goals of the VCHEC is to process waste coal, VEPCO does not explain why the plant is designed to process only limited amounts of waste coal. ROM coal is not waste coal. It can be washed to create cleaner coal for use in conventional and IGCC power plants.

The enabling Virginia legislation (SB1416 and HB 3068) states:

“A utility may also apply a rate adjustment clause for recovery from customers of the costs of (i) a coal-fired generation facility that utilizes

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\(^8\) Letter from Pamela Faggert, Vice President and Chief Environmental Officer, Dominion, to David Pryor, Director, Virginia Department of Environmental Quality, February 19, 2008.
Virginia coal and is located in the coalfield region of the Commonwealth, (ii) one or more other generation facilities, or (iii) one or more major unit modifications of generation facilities, to meet the utility's projected native load obligations. The utility may recover an enhanced rate of return on common equity associated with the type of project, which may include projects utilizing nuclear power, renewable technologies, carbon capture facilities, combined cycle combustion turbines, and conventional coal facilities.”

Based on this language, it does not appear that the Virginia statute requires the use of biomass or coal waste to qualify for the enhanced rate of return. The primary requirement is the use of Virginia coal. Although the statute does not mention “clean coal” technology or IGCC, it does not preclude the use of advanced cleaner coal technologies.

VEPCO states in its filings with the Virginia SCC that higher quality bituminous coal may not available in the Southwest Virginia region. They suggest that only ROM, (unwashed coal) is available. Although unwashed coal will cost less than washed coal, the cost of processing high ash (40 to 50% ash) ROM coal in a CFB plant will add to the cost of electricity and would likely negate any cost advantages of using high ash coals. (Note: most waste coal CFB plants process 100% waste coal and have been financed with “solid waste” tax exempt bonds. This lower cost financing with lower cost fuel supply gives CFB technology an economic advantage over its alternatives. However, the VCHEC is not designed for 100% waste coal and would not qualify for solid waste financing.)

Most bituminous coals in the region are low ash or washed to reduce the ash and sulfur content. A report issued by the Virginia Department of Mines, Minerals and Energy9 provides detailed data on about forty coal deposits in Southwest

Virginia, the location of the proposed VCHEC plant. Although little data is provided on reserves and production, almost all of the coals described in this report are low ash, low sulfur coals. Many of the coals are high swelling index coals that might be valuable for metallurgical markets. These coals would require special washing to meet metallurgical specifications. Most Virginia coals listed in the report are high in pyritic and sulfate sulfur and appear to be well suited for coal washing to reduce sulfur and ash content. In fact, there are many coal washing plants in Virginia operating today. According to the U.S. Department of Labor, Mine Safety and Health Administration ("MSHA"), there are 46 coal preparation plants in Virginia\textsuperscript{10}. 32 of these plants are operating today and 15 of them are in Wise County where the VEPCO VCHEC is to be located. Eight of the Wise Co. coal preparation plants have been constructed in the past 8 years. In a subsequent communication from the MSHA, they provided a list of existing coal preparation plants in Virginia and the daily average production of these coal processing plants.\textsuperscript{11} These data show that the capacity of the Virginia fleet of coal prep plants is about 88,000 tons/day or 30 million tons per year. In it’s response to Mr. Shepherd’s presentation to the VA DEQ\textsuperscript{12}, VEPCO reports that Virginia coal production is about 30 mm tons per year. However, they also assert that an IGCC plant would run out of Virginia coal in 26 years.

In VEPCO’s response to Shepherd, they provide Virginia reserves data from Virginia Tech (Westman) and an attached report from Miltech Energy. VEPCO appears to agree with Shepherd that the coal now being produced in Virginia from


\textsuperscript{12} Attachment 3 “Questions and Answers on Coal Quality and Availability”, VEPCO response to Shepherd’s presentation to the Virginia DEQ, undated.
both underground and surface mines ranges from about 11,800 to 12,900 btu/lb with ash content between about 9 to 17%. This data is consistent with the coal assays contained in the aforementioned Virginia DMR Report 122. These high Btu, low ash coals also appear to be processed coals and VEPCO seems to agree in its response to Shepherd.

VEPCO’s sources indicate that the total reserves of Virginia coal vary from 273 million tons (recoverable reserves at producing mines) to 1349 million tons (mineable reserves). A 630 Mw IGCC plant will require about 1.8 million tons of coal (the high btu processed coal now being produced in Virginia is an excellent coal for an IGCC plant). Therefore, it appears that Virginia has adequate coal reserves for about 150 to over 700 years supply for a typical IGCC plant. In addition, the IGCC plant would consume only about 6% of the current supply of processed coal from coal preparation plants in Virginia.

VEPCO makes a unusual argument that the VCHEC plant will stimulate mining of ROM coal in Virginia. Since the CFB technology is best suited for high ash (40% or more), VEPCO reasons that the VCHEC project will stimulate production of this high ash coal. VEPCO does not provide any information on current production of the fuel it needs for at least 80% of the fuel requirements of the VCHEC project. In its response to Shepherd, it states that the VCHEC will require coal “not currently being mined in Virginia”. VEPCO cites the Alpha Natural Resources deposits of an example of how ROM coal reserves will become economically recovered if the VCHEC project is constructed. VEPCO estimates that 20 million tons of Alpha’s reserves would be proven if a market for ROM coal is created by VCHEC. Considering the high rate of consumption of ROM coal needed by VCHEC, the projected new reserves at Alpha would provide only a 6 year supply of coal to VCHEC. Over the 55 year projected life of the project, the VCHEC project will require about 175 mm tons of ROM coal. Developing a mine to produce this volume of ROM coal for a single customer will require third party investment in mine plant and reserves development. VEPCO has provided no information on why they believe the Virginia mining industry will make the required investment to provide this low
quality coal at a reasonable price for the life of the VCHEC project. However, the data appear to support Shepherd’s position that the existing coal mining and processing industry in Virginia can supply the coal required to operate an IGCC plant for its life.

VEPCO also states that they may process limited amounts of coal waste from local washing plants or retrieve coal waste from existing waste piles. Since there are 15 coal washing plants now operating in Wise Co., it appears that significant volumes of coal waste are produced in the region. However, the VCHEC can process only limited amounts of waste coal and VEPCO does not appear committed to processing even small amounts of this material.

From our reading of the Virginia statutes and coal databases, it does not appear that a CFB technology based project using high ash ROM coal or coal waste is the only choice for a “clean coal” power plant using Virginia coals. An IGCC project would find a ready supply of suitable coal from existing Virginia coal producing facilities and would qualify for the enhanced rate of return as defined by Virginia statute. An IGCC facility would be a much “cleaner” plant, be carbon capture compatible and produce power for a lower price. Appalachian Power (AEP) appears to agree as they have applied to the Virginia SCC for a certificate to build an IGCC plant located in West Virginia with some power flowing to Virginia. On March 7, the West Virginia Public Service Commission approved APC’s certificate of convenience and need for this IGCC project.

10. WATER USAGE

VEPCO states that there are limited supplies of water to operate a SCPC or IGCC plant with conventional wet cooling. To address this problem, VEPCO proposes to use dry or air cooling at the VCHEC. The use of dry cooling reduces plant efficiency and increases the emissions of criteria pollutants and GHG emissions
per unit of useful output. In the aforementioned testimony of AEP’s Michael Rencheck, he discusses fuel flexibility and water usage of an IGCC plant. He stated:

“Finally, the IGCC process requires about one-third less water than a pulverized coal plant, generates less solid waste than a conventional coal plant; and enjoys greater fuel flexibility than conventional coal plants. IGCC plants can utilize a broad range of fuels, including coal from the North Appalachian and Central Appalachian basins, biomass and pet coke. Polygeneration options for IGCC technology can allow the facility to expand into future applications for coal use by producing feed stock for chemicals, fuels and other products. A typical pulverized coal plant cannot produce this option.”

A major report from the US Department of Energy examined the relative performance of IGCC and SCPC operating on bituminous coals\textsuperscript{13}. The data of water usage in this report is consistent with the statements from AEP’s Mr. Rencheck. In addition, it shows the dramatic impact on water consumption for a SCPC plant employing carbon capture technologies. Table 3 below contains our summary of the DOE reported data on raw water consumption for SCPC and IGCC technologies.

\begin{table}[h]
\centering
\begin{tabular}{|c|c|c|c|}
\hline
& SCPC & IGCC & \% change \\
\hline
no Carbon Capture & 594 & 365 & -39\% \\
with Carbon Capture & 1,336 & 501 & -63\% \\
\% change & 125\% & 37\% & \\
\hline
\end{tabular}
\end{table}

The IGCC raw water consumption data are the average of the performance of three technologies (GE, ConocoPhillips and Shell). We normalized the data to show

the water consumption data in gallons per Mw-hour. The SCPC plant consumes more water than IGCC due to the high water needs of the wet scrubbing system. Without carbon capture the IGCC technologies consume about 39% less water.

When carbon capture is added to the SCPC plant, the water consumption rises 125%. However, carbon capture adds only 37% to the water use for the IGCC plants. The enormous increase in water demand for SCPC plant with carbon capture is due mostly to the large cooling loads required by the post-combustion CO₂ scrubbing system. When comparing IGCC with SCPC with carbon capture, the water use by the IGCC technology is 63% less.

Data is not available for the VCHEC CFB plant. However, the application of the same post-combustion scrubbing technology would have a similar effect. If water supply is limited in Southwest Virginia, then building an SCPC or CFB plant in that area would make these technologies even less “Carbon Capture Compatible” than an IGCC plant.

An SCPC plant in the same location as the VCHEC plant would require wet scrubbing and consume more water as stated above. However, an IGCC plant would require about one-third less water. If the water could not be supplied, then the IGCC plant could be air cooled using the same methods proposed by VEPCO. If carbon capture is added, then the IGCC plant would clearly have the lowest water consumption. Although we have not made the calculations, the IGCC plant with the use with dry cooling and carbon capture would be expected to be the lowest water consuming coal to de-carbonized coal to power plant possible.

11. GREENHOUSE GAS EMISSIONS

Numerous bills have been introduced in Congress proposing to limit the emissions of GHGs. Two of the leading bills are the Lieberman Warner bill and the Bingaman and Domenici bill. There is wide agreement that all major GHGs need to be included in any climate change gases, including carbon dioxide, methane and
nitrous oxide. There also appears to a broad consensus that climate change legislation is coming soon. However, the timing of when Congress will pass a bill and the President sign it is not known.

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\(^{14}\). 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\(_2\)O). EPA reports that N\(_2\)O has a GWP factor of 310, which means that one pound of N\(_2\)O emissions is equivalent to 310 lbs of CO\(_2\) emissions.

A principal advantage of a CFB is the lower amount of fixation of nitrogen due to its lower operating temperature. However, it is widely understood that CFB boilers produce more N\(_2\)O than pulverized coal boilers. Formation of N\(_2\)O is favored at the lower temperature combustion conditions in a CFB. A PC boiler operates at much higher temperatures at which formation of nitrogen dioxide (NO\(_2\)) is favored. During the coal combustion process, fuel bound chemical nitrogen is a major source of nitrogen oxide gases, including NO\(_2\) and N\(_2\)O. Nitrogen oxides are also formed from fixation of the nitrogen in the combustion air. A unique feature of a CFB is that the fuel bound nitrogen is preferentially converted to N\(_2\)O, a powerful climate change gas. NO\(_2\) is not considered a climate change gas.

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\(_2\)O is produced.

\(^{14}\) [http://www.epa.gov/nonco2/econ-inv/table.html]
The 2006 IPCC Guidelines for National Greenhouse Gas Inventories provides data for estimating N$_2$O emissions from various coal combustion technologies\textsuperscript{15}. Table 2.6 in the Guidelines (Utility Source Emission Factors) recommends using an emission factor for N$_2$O 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 in the IPCC Guidelines, a default CO$_2$ emission factor for bituminous coal fired PC Boilers of 94,600 kg/TJ\textsuperscript{16}. Using these guidelines to estimate the impact of nitrous oxide emissions, the VCHEC CFB project is estimated to produce N$_2$O emission equal to 310 times 61 or 18,910 kg/TJ of GHG equivalent CO$_2$ emissions. This suggests that the VCHEC 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 VEPCO PSD application) compared to about 8,900 btu/kwhr for a typical supercritical PC plant or IGCC plant operating on washed coal. So the VEPCO 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 VEPCO CFB project will produce about 20% more CO$_2$ gases per unit of power output. If the CFB plant produces N$_2$O at the rate estimated by the IPCC Guidelines, the total GHG emissions per unit of power output (CO$_2$ and N$_2$O measured as equivalent units of CO$_2$) could be about 46% higher than a bituminous coal-fired SCPC or IGCC plant.

Although CO$_2$ and other GHGs such as N$_2$O are not currently regulated, such regulations are widely expected to be enacted soon and these regulations could have a large impact on the VEPCO CFB project. SCPC Boiler and CFB projects that will operate for 40 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


\textsuperscript{16} Id.
mitigate the emission of such gases. As discussed elsewhere in this report, the cost of capturing carbon from a SCPC or CFB plant will be much more expensive than an IGCC plant. Since N₂O is a recognized GHG by the EPA and the IPCC, a CFB plant like the VCHEC will likely incur even higher costs to mitigate or offset N₂O emissions. In VEPCO’s PSD application, the company claims to leave space to add carbon capture equipment in the future. VEPCO does not discuss N₂O emissions or whether the technology exists to mitigate N₂O emissions.

The limited amount of information we could find in the literature suggests that the CFB suppliers are aware of this problem and are working on staged combustion and boiler modifications to reduce N₂O emissions. However, we were unable to confirm if this technology is effective, commercially proven, or available with warranties on the same terms NOₓ and SOₓ are guaranteed. Based on this limited information, we would be concerned that building a CFB plant would take on unknown risks of CO₂ and N₂O regulations and control technologies in the future.

12. CONCLUSIONS

Based on the information that contained in the documents filed by VEPCO with the VA DAQ and the VA SCC, and information from the literature cited in this report, we would offer the following conclusions:

- The VCHEC CFB project produces significantly more air emissions and solid waste and than alternative SCPC and IGCC technologies.
- Based on extensive BACT analysis and reviews of numerous recent IGCC and SCPC projects, IGCC technology produces significantly lower air and solid waste emissions than similarly sized SCPC plants.
- Based on published data for the VCHEC CFB project and alternative SCPC and IGCC technologies, the VCHEC project will produce significantly more greenhouse gases (CO₂ and N₂O) per kwhr of power. As a result, the cost of future carbon mitigation from the VCHEC CFB
The Virginia City Hybrid Energy Center project will be more expensive than for a SCPC plant and much more expensive than for an IGCC plant.

- An IGCC plant would produce electricity at a cost equal to or lower than VCHEC CFB project assuming reasonable levels of reliability (without consideration of carbon capture costs).

- If the cost of carbon capture is factored in and currently available commercial technology is considered, an IGCC plant will have a significantly lower cost of electricity than a CFB or SCPC power plant.

- Based on information from the Virginia Department of Mineral Resources, and data provided by VEPCO in the DEQ hearings, it appears that there numerous deposits of high quality, low ash coal deposits in Southwest Virginia which are suitable for feeding an IGCC power plant thus negating the need to use CFB technology for ROM coals. Data from the US Department of Labor Mine Safety and Health Administration indicates that there are numerous coal washing plants in the region that could supply lower ash and sulfur coal for IGCC facilities. This existing infrastructure could supply a typical IGCC plant for 150 years and much longer as proven reserves are developed to meet the demand of clean coal plants.

- There appears to no existing infrastructure to supply the ROM coal required by the VCHEC project and VEPCO has not provided a business case for why the required infrastructure will be developed by the mining industry. Waste coal appears to be available in the region. However, the proposed VCHEC project can process only limited amounts of this material.

- IGCC and CFB power plants can be designed for a wide range of fuel flexibility. However, it appears that the VCHEC plant is designed only for limited use of waste coals and biomass.
• An IGCC plant uses 33 to 39% less water than a SCPC plant. If dry cooling is used, the more efficient IGCC plant will use less water than the VCHEC plant. If carbon capture is required, then the IGCC plant will use dramatically less water than the CFB plant. Since the cost of carbon capture for VCHEC is prohibitive, the technology for reducing nitrous oxide emissions is not known, and supply of the large amount of water needed for this feature is problematic, it seems likely that VEPCO will be forced to buy large amounts of GHG offsets when climate change regulations are enacted. VEPCO does not appear to have estimated these liabilities in its forecast of the revenue requirements for the VCHEC project.

In summary, the results of our research indicates that the VCHEC CFB plant, when compared to the IGCC alternative, does not appear to be a “clean coal” plant, does not appear to “carbon capture compatible”, has limited fuel flexibility, may not have an assured source of ROM coal at a reasonable price, will use much more water if carbon capture equipment is required, and will likely have to purchase large amounts of GHG offsets in the future, and will likely have the highest life cycle cost of electricity of any of the alternatives available to VEPCO today.
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.

2. On behalf of Wisconsin Energy, Wisconsin Electric Power Permit 03-RV-166, Case No.IH-04-03, Wisconsin Division of Hearings and Appeals.
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
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| 2 | Title V Air Quality Permit, Commonwealth of Kentucky, Dept of Environmental Protection, Permit No. V-02-001 (Rev. 1), December 6, 2002. |
| 5 | Air Pollution Control Construction Permit, State of Wisconsin, Department of Natural Resources, Permit No. 03-RV-166, January 14, 2004, HR from Draft EIS 2003 |
| 6 | PSD Permit Application for the Proposed Virginia City Hybrid Energy Center in Southwestern Virginia June 2006 Updated August 10, 2007, Virginia Dept of Environmental Quality |
| 7 | http://daq.state.nc.us/permits/psd/cliffside.shtml |
| 8 | PSD Application Santee Cooper Pee Dee South Carolina Vol 1 May 2006 |

A Emission Rates per KwHr computed by HEC using published system performance data.
## Summary of BACT Determinations for Recent IGCC Coal Power Plants using Bituminous Coals

<table>
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<tr>
<th>Ref</th>
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<th>Power Project Name</th>
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Notes:
- **A** SO2 adjusted to reflect published operating data
- **B** Pacific Mountain Energy Center includes SCR for NOX Controls
- **C** Excludes Startup/Shutdown, other intermittent, Steady State Operations
- **D** Includes Startup/Shutdown, Calc'd by HEC using final Permit Data
- **E** For Sox, only high sulfur coal and coal projects considered for minimum emission rate
- **F** Emission Rates per KwHr computed by HEC using published system performance data

Ref:
1. Pacific Mountain Energy Center, Application for Site Certification Agreement Appendix B
4. Application to the Minnesota Pollution Control Agency for a NSR Construction Authorization Permit
5. PSD Application, Dominion Resources, Virginia Dept of Environmental Quality, August 2007
6. Application for a TCEQ Flexible Air Quality Permit, Nueces County, Texas, Nueces Syngas LLC
7. PSD Application, Duke Indiana, Indiana Dept of Environmental Management, August 2006
List of Referenced Reports

Studies of SCPC and IGCC with and without Carbon Capture


