Virginia City Hybrid Energy Center
Response to Data Request
Vivian Thomson, Vice Chair, Virginia Air Pollution Control Board

Question (Page No. 2):

More generally, what annual emission levels of criteria pollutants, hazardous air pollutants, carbon dioxide, and N2O would be achieved at the Virginia City Hybrid Energy Center if the BACT and MACT analyses included the best-in-class emission rates from IGCC or pulverized coal facilities? In doing this analysis, please conduct literature searches and obtain information directly from vendors to analyze the most advanced technologies, e.g., IGCC, different coals, coal cleaning, wet flue gas desulfurization, selective catalytic reduction. What are the emission rates for criteria pollutants, hazardous air pollutants, carbon dioxide, and N2O of the permitted IGCC facilities referred to in the National Energy Technology Laboratory's recent report on coal-fired generation plants in the US (National Energy Technology Laboratory 2008)? How does DEQ reconcile the contradictory claims of Dominion, on the one hand, and the Hensley Report, on the other hand, concerning potential emission rates of conventional and hazardous pollutants from IGCC facilities relative to the Virginia Hybrid Energy Facility's CFB proposal (Hensley Energy Consulting 2008, Dominion Resources Services 2008)?

Response:

With respect to the criteria pollutants and hazardous air pollutants, the reference found in Attachment 7 of the March 6, 2008, submittal (Attachment 1) explains that, because IGCC and PC would redefine the project, they would not be included in a lawful BACT analysis. Because they are not "similar sources", they would not be included in a MACT analysis. However, a study was done to compare criteria pollutants between VCHEC's CFB boilers, PC technology and IGCC technology (Attachment 2). With respect to CO_2 and N_20, the New Source Review program does not impose any requirements for CO_2 or N_2O.

Dominion has developed an integrated strategy to meet the growing energy needs of our customers in an environmentally responsible, reliable and cost-effective manner. This strategy includes working with policymakers to design new incentives to reduce greenhouse gas emissions by improving the efficiency with which Dominion and our customers use energy, and for building low-carbon and non-emitting generation facilities as well as those whose carbon emissions can be captured and sequestered.

To meet our customers' needs, it will be necessary to rely on a variety of tools and each tool is an integral part of our approach. Conservation, renewable generation development, the construction of other generating capacity and supplemental infrastructure improvements will help maintain fuel diversity on our system while meeting our customers' needs in an environmentally responsible manner.

Dominion supports federal legislation to address the global problem of climate change that:

- Regulates greenhouse gas emissions economy-wide,
- Establishes a system of tradable allowances,
- Slows the growth of greenhouse gas (GHG) emissions in the near term and reduces GHG emissions in the long term,
- Sets a realistic baseline year and schedule of compliance,
- Promotes technology development, and
- Includes a "safety valve" to protect consumers from dramatic and potentially ruinous rate increases.

Furthermore, we are actively pursuing research on carbon capture, transport and storage technologies.

Dominion is gaining hands-on experience with technologies related to carbon capture. In October 2007, Dominion announced that it will host a large-scale coal gasification test facility and research center at our Brayton Point Power Station in Massachusetts. The test facility owned by GreatPoint Energy will convert coal, petroleum coke and biomass into pipeline-quality natural gas and a separate stream of sequestration-ready carbon dioxide. The process also captures mercury, sulfur and other pollutants.

Dominion is also one of the leading gas transport companies in the world and can apply this experience to the transportation of carbon dioxide from capture to storage.

Successful commercial application of carbon storage on a utility scale is a critical part of our energy future. With regard to carbon storage, Dominion is a major sponsor of research being conducted by Virginia Tech on carbon storage in unmineable coal seams. Some of the most-promising potential sites for carbon storage are in the Virginia coalfield region, near the location of this project. This proximity would substantially simplify the process of carbon transport and would enable effective carbon storage.

On November 3, 2007, Dominion announced our contribution of $500,000 to the Virginia Center for Coal and Energy Research at Virginia Tech. This contribution is to support a planned full-scale carbon storage demonstration project, to be located in close proximity to the project site in adjacent Russell County.

Our financial support makes it possible for Virginia Tech to qualify for substantial funding from the U.S. Department of Energy.

A. PSD Requirements - Pollutant Must Be "Subject to Regulation" Under the CAA

The CAA requires the construction of a new major stationary source of air pollutants to receive a PSD permit. 42 U.S.C. § 7475(a); 40 C.F.R.§ 52.21(a)(2)(iii). A PSD permit must include a BACT limit for "each pollutant subject to regulation" under the Act for which emissions exceed specified significance levels. 42 U.S.C. § § 7475(a), 7479; 40 C.F.R. § § 52.21(b)(1), (b)(2), (b)(12), (b)(50) & (j)(2). BACT is further required "for each regulated NSR pollutant that [a source] would have the potential to emit in significant amounts." 40 C.F.R. § 52.21(j)(2).

EPA has defined "Regulated NSR pollutant" as:

> i) Any pollutant for which a national ambient air quality standard has been promulgated and any constituents or precursors for such pollutants identified by the Administrator (e.g., volatile organic compounds and NOx are precursors for ozone);
>
> (ii) Any pollutant that is subject to any standard promulgated under section 111 of the Act;
>
> (iii) Any Class I or II substance subject to a standard promulgated under or established by title VI of the Act; or
>
> (iv) Any pollutant that otherwise is *subject to regulation under the Act*; except that any or all hazardous air pollutants either listed in section 112 of the Act or added to the list pursuant to section 112(b)(2) of the Act, which have not been delisted pursuant to section 112(b)(3) of the Act, are not regulated NSR pollutants unless the listed hazardous air pollutant is also regulated as a constituent or precursor of a general pollutant listed under section 108 of the Act.
> 40 C.F.R.§ 52.21(b)(50) (emphasis added).

Therefore, an air pollutant must be "subject to regulation" (and emitted over a specified significant amount) under the CAA for it to be considered a regulated NSR pollutant and for a BACT analysis to be required in a PSD permit. By contrast, EPA and delegated permitting authorities "lack[] the authority to impose [PSD permit] limitations or other restrictions directly on the emission of *unregulated* pollutants." *North Country Resource Recovery Assoc*., 2 E.A.D. 229, 230 (Adm'r 1986) (emphasis added).

B. CO_2 is not "subject to regulation" under the CAA

1. EPA's Longstanding and Reasonable Interpretation of "Subject to Regulation" Means "Subject to Actual Emission Controls"

CO_2 is not currently subject to regulation under the CAA and, in fact, has never been regulated as a pollutant under the Act. While the term "subject to regulation" is not

defined in the CAA, EPA has historically taken the position that "subject to regulation under the Act" for PSD permitting purposes includes "*only those air pollutants for which actual emission control requirements exist. . . .*" *In re Christian County Generation*, PSD Appeal 07-01, Brief of EPA Office of Air and Radiation (Sept. 24, 2007) (*Christian County* EPA Brief) at 4-5 (emphasis added). *See* Memorandum from Lydia N. Wegman, OAQPS Deputy Director, *Definition of Regulated Air Pollutant for Purposes of Title V* (April 26, 1993) at 4-5 (explaining which pollutants are "subject to regulation under the Act" for Title V permitting purposes and noting that the interpretation was similar to the approach taken in PSD permitting). This memorandum specifically suggested that CO_2 would not be considered subject to regulation under Title V because there were no actual controls of CO_2 emissions in the Act. *Id.*[1]

Moreover, EPA has generally identified specific pollutants subject to regulation in its regulations and rulemakings under the PSD and NSR programs. *See, e.g.*, 43 Fed. Reg. 26388, 26397 (June 19, 1978) (describing pollutants subject to BACT requirements as those pollutants actually regulated under various CAA provisions); 45 Fed. Reg. 52676, 52723 (Aug. 7, 1980) (noting that BACT is required for criteria pollutants and also those regulated under NSPS and NESHAP since "[i]n this manner, BACT can complement the NSPS process by extending coverage to additional source types and units and perhaps identifying candidates for future NSPS and NESHAP regulations."); 61 Fed. Reg. 38249, 38309-10 (July 23, 1996) (listing pollutants subject to PSD review and including only those pollutants actually regulated under existing emission control provisions of the CAA.)[2]

Most recently, EPA adopted this interpretation in its promulgation of regulations defining a "regulated NSR pollutant" under 40 C.F.R.§ 52.21(b)(50), a definition that was never

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[1] The Wegman memorandum adopts a narrow definition of "air pollutant" that would exclude CO_2, and it is acknowledged that such a narrow definition was rejected by the Supreme Court's recent ruling in *Massachusetts v. EPA*, 127 S. Ct. 1438, 1460 (2007). However, the Supreme Court did not determine what pollutants were "subject to regulation" under the CAA for permitting purposes. Hence, the Wegman analysis on this point is still relevant and instructive. Indeed, as will be discussed below, the Supreme Court expressly did not hold that CO_2 must be regulated under the CAA; rather, it left that determination to EPA's discretion as long as the Agency provided a lawful explanation of its decision whether or not to regulate.

[2] S*ee also* EPA, *New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting* (Oct. Draft)(1990), at A.18-21 & Table A-4 (identifying pollutants "regulated by the Clean Air Act" as those having emissions rates in tons/year and listing those pollutants; CO_2 is not listed); B.4 ("the BACT determination must separately address for each regulated pollutant with a significant emissions increase at the source, air pollution controls for each emission unit or pollutant emitting activity subject to review"); & 1.1 ("Some pollutants may not be subject to regulation . . .. such that they don't require major source review.")

challenged in court. That definition includes four categories. The first three categories include only those pollutants for which emission control measures are required under three principal CAA programs: 1) pollutants for which national ambient air quality standards (NAAQS) have been promulgated (and any constituents or precursors of those pollutants); 2) pollutants subject to a section 111 New Source Performance Standard (NSPS); and 3) class I or II substances under CAA Title VI (stratosphere ozone). 40 C.F.R. § 52.21(b)(50)(i)-(iii). The final category includes a "catch-all" phrase: "any pollutant that otherwise is subject to regulation under the Act" (excepting certain hazardous air pollutants listed in section 112 or subsequently added to the list). 40 C.F.R. § 52.21(b)(50)(iv). Yet, in including this last category, EPA did not intend to depart from its practice of considering as regulated pollutants only those substances with specified actual emission controls under the Act. In fact, EPA did not even reference this last subsection in its final 2002 rulemaking setting forth § 52.21(b)(50). It simply explained which programs (NAAQS, NSPS and Title VI) were included in the definition and it specifically listed those pollutants that are "currently regulated under the Act" which "are subject to Federal PSD review and permitting requirements." 67 Fed. Reg. 80186, 80240 (Dec. 31, 2002). CO_2 was not listed as one of those pollutants nor did EPA specify it as among those pollutants covered by 40 C.F.R. § 52.21(b)(50).

The purpose and meaning of 40 C.F.R. § 52.21(b)(50)(iv) can best be understood by considering it in the context of the other specific references listed in (b)(50) to existing CAA programs where pollutants are specified and subject to specific emissions limitations. See*, e.g. American Mining Congress v. USEPA*, 824 F.2d 1177, 1189-1190 (D.C. Cir. 1987) ("where general words follow the enumeration of particular classes of things, the general words are most naturally construed as applying only to things of the same general class as those enumerated.") Similarly, EPA reasonably interprets the phrase "otherwise is subject to regulation under the Act" as referring "only to air pollutants that are presently subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant." *Christian County* EPA.

Hence, under 40 C.F.R. § 52.21(j)(2), EPA would only apply BACT to those pollutants specifically subject to actual emissions controls under the Act. Significantly, the definition of "regulated NSR pollutant" under the 2002 rulemaking did not include CO_2 despite the fact that, under EPA's then-current legal interpretation, CO_2 was considered to be an "air pollutant" that EPA had the *authority to regulate* were it to make the necessary threshold regulatory determinations, *e.g.* endangerment to human health or the environment. *See* EPA Office of General Counsel, *EPA's Authority to Regulate Pollutants Emitted by Electric Power Generation Stations* (Apr. 10, 1998) ("Cannon memorandum"). That interpretation was not withdrawn until August 28, 2003, when the then-serving EPA General Counsel concluded that the Cannon memorandum no longer represented the views of EPA's General Counsel. *See* EPA Office of General Counsel, *EPA's Authority to Impose Mandatory Controls to Address Global Climate Change under the Clean Air Act*, (Aug. 28, 2003) (Fabricant memorandum). This fact reinforces the conclusion that EPA has never considered CO_2 to be "subject to regulation" under the CAA even when it believed it had authority to regulate the substance as an air pollutant under the CAA.

EPA's longstanding practice of considering "subject to regulation" only those pollutants for which actual emissions controls are effective also has never been subject to challenge, and is reasonable and entitled to deference as a "permissible construction of the [CAA]." *See Chevron U.S.A. v. NRDC*, 467 U.S. 843-44 (1984); *see also Environmental Defense v. Duke Energy Corp*., 127 S. Ct. 1423, 1433-1434 (2007) (finding that EPA had discretion to define relevant CAA terms in the context of implementing the PSD program).

This practice is also supported by case law at the administrative and federal court levels which have interpreted "subject to regulation" for purposes of PSD and BACT. *See, e.g. In re Indeck-Elwood*, PSD Appeal No. 03-04 (Sept. 27, 2006, slip op at 8 n.10 (noting that EPA regulations define "regulated pollutants" as those "subject to regulations" under the CAA, including NAAQS, Section III and Title VI); s*ee also Alabama Power*, 636 F.2d 323, 370 n.134 ("Once a standard of performance has been promulgated for [certain particulates], those pollutants become 'subject to regulation' within the meaning of section 165(a)(4), 42 U.S.C. § 7475(a)(4) (1978), the provision requiring BACT prior to PSD permit approval.")

Similarly, the Environmental Appeals Board has generally supported EPA's differentiation between regulated and unregulated pollutants in the PSD and other contexts, agreeing that only the former require consideration in PSD permitting or other conditions or controls. *See, e.g., In re Knauf Fiber Glass*, 8 E.A.D. 121, 163-64 (EAB 1999) (finding "additional [PSD] permit conditions relating to emissions of respirable glass fibers" were not required because these fibers were "unregulated pollutants" not specifically addressed by CAA emission control requirements; they were to be addressed only to the extent that they were components of PM_{10}, a regulated criteria pollutant); *In re Kawaihae Cogeneration Project,* 7 E.A.D. 107, 132 (EAB 1997) (upholding a PSD permitting decision excluding consideration of CO_2 because there were "'no regulations or standards prohibiting, limiting or controlling the emissions of greenhouse gases from stationary sources'"); *In re Umetco Minerals Corporation*, 6 EAD 127, 127-128 (EAB 1995) (finding radon emissions from uranium byproducts that result from uranium milling are subject to regulation under the CAA, and more specifically, that EPA has designated these substances as hazardous air pollutants subject to national emissions standards); *In re Inter-Power of NY*, EAD 130, 151 & n.36 (1994) (holding that EPA is not required to examine control technologies for CO_2 and hydrogen chloride, which are unregulated pollutants); *In re Genesee Power*, 4 EAD 832, 848 (1993) (stating that "unregulated pollutants generally do not form part of the BACT analysis, since by statute and regulation, BACT is defined as an emission limitation for a regulated pollutant" and noting "the environmental impact of unregulated pollutants" only becomes relevant when it comes to "the selection of an appropriate control technology for regulated pollutants").

Moreover, as will be discussed below, EPA's interpretation is the only practical way for the Agency to implement its statutory obligations and PSD permitting program, since otherwise, EPA would need to consider BACT for virtually any substance that might

arguably fit within the CAA's broad definition of "air pollutant," even where no actual emissions controls exist under the Act for the pollutants in question.

2. CO_2 Is Not Subject To Actual Emission Controls

CO_2 is not "subject to regulation" under the CAA because there are no actual emissions controls applicable to CO_2 in the CAA. Thus, it is not a "regulated NSR pollutant," and it need not be considered in a PSD permit or in a BACT analysis.

a. CO_2 is not subject to CAA controls

There are no statutory provisions in the CAA that establish actual controls for CO_2 emissions, and, at the present time, EPA has not regulated emissions of CO2 from any sources.[3]

Some have argued that PSD applies for CO_2 by virtue of the existence of section 821 of Pub. L. 101-459, 104 Stat. 2699, which requires certain electric utility sources to monitor and report CO_2 emissions and requires EPA to make such emissions data publicly available. However, although Section 821 was passed as part of the Clean Air Act Amendments, it is not part of the CAA. *See* Committee on Energy and Commerce, U.S. House of Representatives, *PROVISIONS OF THE CLEAN AIR ACT AMENDMENTS OF 1990 (PUBLIC LAW 101-549) THAT DID NOT AMEND THE CLEAN AIR ACT*," Committee Print 107-H, Compilation of Selected Acts Within the Jurisdiction of the Committee on Energy and Commerce (May, 2001) at 451 (listing section 821 as "Information Gathering on Greenhouse Gases Contributing to Global Climate Change"). Rather, Section 821 is set forth in a note to 42 U.S.C. § 7651k and applies independently of the CAA, though it does incorporate by reference section 412(e) of the CAA into section 821's reporting requirements, which makes it unlawful to operate the unit if the electric utility fails to report CO_2 emissions. Because it is not part of the CAA, even if section 821 were considered a regulatory provision establishing a standard for or setting a limit on emissions, which it is not, it would not be a regulation *under the CAA*.

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[3] Even if EPA made the necessary findings under certain provisions of the Act as a first step in establishing regulatory control over CO_2, that would not necessarily mean CO_2 was immediately "subject to regulation." For example, under CAA section 202(a)(1), EPA must make an endangerment finding before it may establish emission controls for a pollutant from new motor vehicles or engines. Section 202(a)(2) goes on to provide: "Any regulation prescribed under section [202(a)(1)] . . . *shall take effect* after such period as the Administrator finds necessary to permit the development and application of the requisite technology, giving appropriate consideration to the cost of compliance within such period." 42 U.S.C. § 7521(a)(2) (emphasis added). Therefore, even if EPA made an endangerment finding and promulgated a regulation establishing emission controls on CO_2 under section 202(a)(1), the substance would not be "subject to regulation" at least until the regulation was final and had taken effect following a period determined necessary by the Agency for development and application of requisite technology for motor vehicles.

In any event, even if section 821 were considered part of the CAA, the provision does not establish emissions controls. The provision simply requires specified units to monitor and report their CO_2 emissions, but these sources have no limits on the amounts of CO_2 they may emit and are not required to install or establish any controls on their CO_2 emissions. It is hard to conceive that such provisions, which Congress characterizes as "Information Gathering," *id*., are in any way similar to NAAQS, NSPS, Title VI or other programs which set forth emission control requirements for regulated pollutants.

As stated above, EPA has never considered CO_2 to be regulated as a pollutant under the CAA Indeed, even in the Cannon Memorandum, EPA stated that "'while CO_2 emissions are within the scope of EPA's authority to regulate, the Administrator has made no determination to date to exercise that authority under the specific criteria provided under any provision of the Act.'" And, as noted above, EPA did not include CO_2 in the list of pollutants subject to regulation in its 2002 rulemaking defining regulated NSR pollutants even though the Agency interpretation in the Cannon memorandum had not been withdrawn at that time.

The Wegman memorandum specifically mentions CO_2 as an example of a substance that is not subject to Title V permitting because it is not subject to actual control of emissions (a conclusion the memorandum notes as equally applicable to the PSD context). In that memorandum, EPA, referring specifically to section 821, concluded that that such requirements "involve actions such as reporting and study, not actual control of emissions" and "do not preempt EPA's discretion to exclude these pollutants in determining whether a source is major." Wegman memorandum at 5. The Wegman memorandum went on to list regulated air pollutants as of April 1993, and did not include CO_2.

Significantly, the EAB has agreed that CO_2 is not regulated under the CAA. For example, in *Inter-power of New York*, 5 E.A.D. at 151, the EAB found that EPA was not required to examine technologies aimed at controlling CO_2 under the PSD program and in a BACT analysis because it was an unregulated pollutant. In *Kawaihae Cogeneration Project*, the EAB upheld a PSD permit in which the permitting authority found that CO_2 was not "'a regulated air pollutant for permitting purposes.'" 7 E.A.D. at 132.

b. <u>*Massachusetts v. EP*A does not subject CO_2 to regulation</u>

The Supreme Court in *Massachusetts v. EPA* determined that CO_2 falls within the "sweeping" definition of "air pollutant" in section 302(g) of the Act, which, the Court held, encompasses "all airborne compounds of whatever stripe." 127 S. Ct. at 1460. Having concluded that CO_2 is an "air pollutant," however, the Court explained that EPA has authority to regulate CO_2 under section 202(a)(1) *only* "[i]f EPA makes a finding of endangerment" under that provision. *Id* at 1462. While the Court rejected EPA's reasons for denying a petition to regulate CO_2 from new motor vehicles and engines as outside the scope of the CAA, it noted the limited nature of its decision: "We need not and do not reach the question whether on remand EPA must make an endangerment

finding, or whether policy concerns can inform EPA's actions in the event that it makes such a finding." *Id*. at 1463. Thus, while the Court found that EPA has *authority* to regulate CO_2 emissions from new motor vehicles and engines if it determines that those emissions cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare, the question whether sufficient information exists to make this finding was expressly left to the Agency to resolve, and that question remains unresolved.

Consequently, the Supreme Court's opinion does not render CO_2 "subject to regulation" under the CAA for purposes of the PSD program. It is not sufficient that CO_2 could become subject to regulation under the CAA in the future if certain events occur. Pursuant to longstanding EPA interpretation - and logic - only those pollutants currently subject to actual emissions controls are regulated pollutants.

3. <u>It Would Be Inappropriate To Regulate CO_2 Through Such An Ad Hoc Approach</u>

The issue of whether CO_2 can or should be subject to emission controls under the CAA or new legislation is a controversial matter which is under a very current and public debate. EPA has already announced it is "exploring options for addressing GHG emissions in response to the Supreme Court decision, but the Agency has not yet issued regulations requiring control of CO_2 emissions under the Act generally or the PSD program specifically." *Christian County* EPA Brief at 10.

The question whether CO_2 emissions should be part of a PSD permitting program or subject to BACT analysis necessarily raises a number of important policy and technical issues. For example, what level of CO_2 emissions should be considered significant for PSD regulations? CO_2 is emitted from many sources, including private homes, office buildings, and shopping centers in addition to larger stationary sources Further, if CO_2 were subject to BACT, what would be the appropriate emission limits and control technology?

EPA would need to answer these and other questions through careful scientific and technical review, and, based on this analysis, promulgate regulations through a notice and comment rulemaking process. They are issues of national importance that must be addressed on a national basis. The PSD permitting process, however, is a case-by-case approach, and individual facility permitting determinations do not have the effect of nationwide regulatory decisions. PSD permitting of CO_2 emissions could lead to different emission levels and determinations on control technology plant-by-plant, and would be influenced by specific local factors as well as the comments of those local interests commenting on the permits.[4] Such an "ad hoc" method (or taking a contrary

[4] For example, EPA Region IX issued comments on a draft environmental impact statement by the Bureau of Land Management that a BLM permit for a power plant should address the potential impact of California's recently enacted interim GHG emissions performance standard since that standard could directly impact the ability of

position to EPA on what is "subject to regulation" under the CAA) is no way to approach a regulatory issue of such complexity and significance to the U.S. economy and power supply.

The Supreme Court has held that the definition of "air pollutant" to be "sweeping," encompassing virtually any substance found in the ambient air, including water vapor. If EPA were required to consider for PSD permitting and a BACT analysis any substance found in the air, including those have not been subject to emissions controls under the CAA, the Agency would be quickly overwhelmed. The PSD program does not require EPA to take this path. *See Knauf Fiber Glass*, 8 E.A.D. at 162 ("Not all air pollutants are covered by the federal PSD review requirements.")

4. Conclusions

For all the reasons stated above, EPA has not considered and should not and need not consider CO_2 in its PSD permit decisions or subject CO_2 emissions to a BACT determination.

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the coal-fired power plant at issue to sell electricity to California. EPA Region IX, *Draft Environmental Impact Statement for the White Pine Energy Station Project, Nevada [CEQ # 20070151]* (June 22, 2007) at 14. While the Region recommended that the final EIS discuss carbon capture and sequestration and other means of capture and storage of CO_2 as a component of the proposed alternatives, *id*., the Region's recommendations (which did not arise in the context of a PSD permit but rather in the context of review under the National Environmental Policy Act of a permit to use BLM-administered lands) fall far short of requiring consideration of BACT or specific CO_2 emissions limitations in PSD permits, and do not change the official Agency position on that issue, as most recently articulated in the EPA brief in *Christian County.*

ATTACHMENT 1

Authority o the Board and DEQ to Consider uels, ocation, Control Technology and ther Alternatives in ssuing Prevention o igni icant Deterioration Permits

At the January 25, 2008 State Air Pollution Control Board ("SAPCB" or "Board") meeting, the Board requested an evaluation of the authority of the Virginia Department of Environmental Quality ("DEQ") and the Board to consider alternatives to the proposed "site, technology, control, fuel, fuel characteristics and limits, fuel cleaning and preparation, emission limits, and operating restrictions" in the context of issuing permits.[1] Alternatives of certain of these parameters are typically considered within the context of the best available control technology ("BACT") analysis or air quality analysis (e.g., fuel characteristics, fuel cleaning and preparation, and emission limits). Regardless of either the Board's or DEQ's authority in the abstract to consider these parameters, it is essential to keep in mind findings by the General Assembly and the State Corporation Commission that it is in the public interest to construct a power plant in southwest Virginia that will burn Virginia coal. These are precisely the goals, aims and objectives of the Virginia City Hybrid Energy Center.

In sum, while the Board and DEQ might appear to have broad discretion to consider a wide range of factors in issuing a permit, their authority to consider, much less impose, alternatives with regard to this project is limited by 1) the express intent of the Virginia General Assembly to promote economic development by locating a power plant in the coalfield region of Virginia to burn local coal; 2) the Boards' regulations which set out specific analysis and criteria for implementing the Board's and DEQ's permitting authority and 3) a long line of established Virginia and EPA precedent on the appropriate role of a permitting authority.

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[1] This request was also made in a letter from David Paylor of the DEQ to Pamela Faggert of Dominion dated January 30, 2008.

The Board has four, broad, statutory criteria for approving permits. It must consider (1) public safety and health, and reasonable use of property; (2) the social and economic value of the activity to be permitted; (3) the suitability of the activity for the area in which it is located; and (4) the scientific and economic practicality of reducing emissions. Va. Code § 10.1-1307. E.1.-4.

The first criterion is typically addressed by the air quality analysis that is performed under the PSD program to demonstrate that the applicable air quality standards will be protected. In issuing the draft permit, the DEQ has determined that VCHEC satisfies these requirements. Air quality impacts from the project and alternatives thereto, are also the subject of the public comment process required under the PSD program. That process is currently underway.

The second and third criteria are addressed in the case of VCHEC by legislation promoting economic development through the construction of a power plant in southwest Virginia burning Virginia coal and declaring such a plant to be in the public interest. See Va. Code § 585.G (repealed); Va. Code § 56.585.1.A.6. Based on that legislation, the Virginia State Corporation Commission has determined that, as a coal fired generation facility that uses Virginia coal and is located in the Virginia coalfield region, VCHEC is in the public interest. While one might argue that the finding of public interest was intended to satisfy a specific regulatory requirement, for the Board or DEQ to consider, much less require, an alternative plant outside the coalfield region using imported coals would frustrate the intent of the General Assembly. Moreover, with respect to site suitability, the General Assembly and the Board, in its regulations and longstanding policy, have deferred this question to the local government where the plant it to be located.

The fourth criterion is addressed by the best available control technology ("BACT") analysis for the VCHEC facility as part of the PSD permitting process. Virginia has followed

EPA and a majority of states in not using BACT to redefine a project as proposed by the applicant. Thus, no alternatives analysis, other than that otherwise required in a PSD permitting analysis (alternatives properly considered in the BACT or air quality analyses), is required with respect to VCHEC.[2] Each of the Board's four criteria is discussed in the context of VCHEC below.

- **Air Quality mpacts**

The first criterion is a consideration of the air emissions impacts anticipated from the source. The PSD rules require several analyses to address air emissions impacts including (1) demonstration of compliance with the national ambient air quality standards, which are established to protect both human health and the environment, 9 VAC 5-80-1715; (2) demonstration of compliance with increments, which are established to prevent a significant deterioration in air quality; id. (3) consideration of impacts on Class I area air quality related valued ("AQRVs"), including visibility and deposition impacts, 9 VAC 5-80-1765; and (4) an analysis to assess the impacts to visibility, soils and vegetation as a result of emissions (including emissions of metals such as mercury) from the source plus emissions from associated growth, 9 VAC 5-80-1755. All of these analyses work together to provide a complete picture of the anticipated impacts from source emission. For VCHEC, these analyses are included in the application materials and the preliminary determination by DEQ as evidenced by the draft

[2] DEQ's authority is derived from Va Code § 10.1-1183(10) (purpose is to promote environmental quality through, among other things, "expeditious and comprehensive permitting"), Va Code § 10.1-1186(5) (power to implement regulations adopted by the Board), and Va Code § 10.1-1322(A) (DEQ has the authority to issue permits pursuant to the regulations of the Board). In addition to DEQ's statutory permitting authority, the Board has conferred upon DEQ the decision-making powers that are contained in 9 VAC Part 5, including permitting decisions. 9 VAC 5-20-10(D); 9 VAC 5-170-180(A).

permit, which demonstrate the project's compliance with respect to air quality impacts and protection of public health and welfare.

A permitting agency must also afford an opportunity for and respond to public comments on air quality impacts related to the project and alternatives to it. See Clean Air Act § 165(a); 9 VAC 5-80-1775. F.6 This is a procedural requirement. The agency's substantive authority in responding to those comments is nevertheless limited by the four criteria in Va Code 10.1-1307 E. as described herein.

2. ocial and Economic Value

As to the second criterion, the social and economic value of the activity, the Virginia General Assembly has determined that a power plant located in southwest Virginia designed to burn Virginia coals, such as VCHEC, will "ensure a reliable and adequate supply of electricity, to meet the utility's projected native load obligations and to promote economic development." *See* Va. Code § 56-585.G (repealed); Va. Code 56-585.1.A.6. The General Assembly and the State Corporation Commission has determined that such a plant is in the public interest. *Id*; *In re Virginia Electric and Power Company*, Case No. PUE-2006-00075, Final Order of the SCC at 4 (Nov. 1, 2006).[3] These determinations are dispositive of any question of the social and economic value of VCHEC; moreover, to impose an alternative design on VCHEC would contravene the clear intent of the legislature.

To the extent there remains any question about the social and economic value of VCHEC, in 2007 Governor aine made it the policy of the Commonwealth to work towards greater energy security. The Governor's Virginia Energy Plan states:

[3] While the "public interest" language of Va. Code § 56.585.G was repealed in 2007, it is essentially restated in Va. Code § 56-585.1.A.6. "The construction of any facility described in clause (i) [referring to 'a coal-fired generation facility that is using Virginia coal and is located in the coal-field region of the Commonwealth ''] is in the public interest".

> Virginia will need a broad mix of energy sources over the next ten years. New technologies should expand the state's energy portfolio, including prudent investments in projects such as the Virginia City Hybrid Energy Center's fluidized bed coal power plant "

This station will provide long term economic benefits to the residents of southwest Virginia. An independent analysis by Virginia Tech found that the proposed station would more than double the economic output of Wise County. Dominion will invest $1.8 billion in the local economy, adding upwards of $6 million in tax revenues each year. The station itself will have an annual payroll of over $ 4 million and will create more than 1,200 jobs for the people of southwest Virginia.

. **and se**

Criterion 3 is a combination of local land use issues and the anticipated air quality impacts in the area. While this criterion provides authority for the Board to consider the appropriateness of the location, it does not necessarily extend to the Board the authority to request an analysis of other locations. In any event, as with criterion 2, the language of Va. Code § 56-585.1.A.6 clearly states the General Assembly's determination that a power plant located in Southwest Virginia is in the public interest. Moreover, the General Assembly and the Board itself have previously determined that questions of suitability are best left to local governments. Va. Code § 10.1-1321.1 provides that a permit may not be issued unless the governing body of the locale has determined that the location and operation of the source is consistent with all applicable ordinances. The Board's regulations impose a similar requirement. 9 VAC 5-80-1665. Such a determination has been made for VCHEC and submitted to DEQ as part of the PSD application. The Board has also adopted a policy that it will leave to local government the decision of whether a source should be located within that locale's jurisdiction. As explained in it's 1987 Suitability Policy, the Board will not interfere with a local government's suitability

determination, but would instead makes its decision to approve or disapprove a permit application based only on air quality issues.

. **BACT**

Finally, the fourth criterion, scientific and economic practicality of reducing or eliminating emissions, is addressed by the PSD best available control technology ("BACT") analysis. 9 VAC 5-80-1705. The BACT analysis consists of identifying available controls, on a pollutant-by-pollutant basis, to reduce or eliminate emissions and requires either a scientific (technical) or economic justification if the best identified control is not used as the basis for establishing the emission limitation. Several of the parameters identified by the Board are addressed by the BACT analysis. Specifically, control technology, fuel, fuel characteristics, fuel cleaning and preparation, emission limits, and operating restrictions can all be considerations in the BACT analysis. Information currently in the permit record supports the BACT analysis for VCHEC. Based on the applicable statutes and regulations, and EPA and DEQ interpretations of them, the alternative of IGCC (or any other alternative that would redefine the project), however, is not appropriately considered in the BACT analysis for the reasons discussed below.

A. BACT Does Not Rede ine the Pro ect

The longstanding interpretation of the Best Available Control Technology ("BACT") requirement has been that BACT does not redefine the source (i.e., it does not change the fundamental characteristics of the proposed source). This interpretation is founded on a reasonable interpretation of the Clean Air Act ("CAA"), which provides that a major emitting facility may not be constructed unless, among other things, the "*proposed facility* is subject to [BACT] for each pollutant [from] such facility." 42 U.S.C. § 7475(a)(4) (emphasis added). In turn, the CAA defines "BACT" as:

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

42 U.S.C. § 7479(3) The Virginia regulations imposing and defining BACT are similar to this and identical to the federal regulations defining BACT. 9 VAC 5-80-1615, 1705.B.

As both the CAA and the regulations implementing the PSD program make clear, the case-by-case analysis pursuant to which a BACT determination is ultimately made must have a starting point -- the "proposed facility" or source. *See* 42 U.S.C. § 7475(a)(4) (providing that a permit may be issued to a "major emitting facility" if "the *proposed facility* is subject to [BACT]"); 9 VAC 5-80-1615: 40 C.F.R. § 52.21(b) (12) (applying BACT to a "*proposed* major stationary source"). A straightforward reading of the statute's language and the structure of the PSD permitting provisions leads to the reasonable conclusion that BACT applies to the source that the applicant is proposing to build.

In other words, the BACT determination process does *not* present an opportunity for the permitting authority to dictate that the applicant consider, much less build, something fundamentally different from what has been proposed. Rather, the scope of the BACT analysis *i.e.*, the range of "production processes, and available methods, systems and techniques" considered is constrained by the requirement that BACT be applied to the "*proposed* facility."

Contrary to statements by Don Shepherd, an employee of the National Park Service, at the January 25, 2007 meeting, the EPA and the Commonwealth of Virginia have consistently taken this position. *See* EPA Region 8, Response to Public Comments on Draft PSD Permit to

Construct for Deseret Power, No. PSD-OU-0002-04.00, (Aug. 30, 2007) ("Region 8 Response"); In re SEI Birchwood Inc., 5 E.A.D. 25 (1994); In re Old Dominion Electric Cooperative 4 E.A.D. 779 (1992) (permits issued by the Virginia State Air Pollution Control Board under delegation from EPA for coal-fired power plants did not require consideration of natural gas fired turbines in the BACT analysis because that is fundamentally different process and to require such consideration would redefine the project). Based on the statutory language requiring application of BACT to the "proposed facility," EPA has long recognized, in a consistent line of adjudicatory precedent and guidance, that the BACT process is "not a means to redefine the design of the source when considering available control alternatives." *See*, *e.g.*, New Source Review Workshop Manual at B.13 (Oct. 1990) (draft) ("NSR Manual").[4] EPA has repeatedly stated the policy in the context of PSD permit appeals:

> Permit conditions are imposed for the purpose of ensuring that the proposed source . . . uses emission control systems that represent BACT. . . . These control systems, as stated in the definition of BACT, may require application of "production processes and available methods, systems, and techniques. . ." to control the emissions. . . . The permit conditions that define these systems are imposed on the source *as the applicant has defined it*. . . . [T]he conditions themselves are not intended to redefine the source.

In re Pennsauken County, N Res. Recovery Facility, 2 E.A.D. 667, 673 (Adm'r 1988) (emphasis added) (upholding agency refusal to require a coal-fueled power plant be built when a municipal waste/coal-fueled facility was proposed); *see also In re Spokane Reg'l Waste-to-Energy*, 2 E.A.D. 809, 811 (Adm'r 1989) (acknowledging EPA will not require a PSD applicant to "change the fundamental scope of its project" in reviewing BACT); *In re Hawaiian Commercial Sugar Co.*, 4 E.A.D. 95, 99-100 (EAB 1992) (rejecting argument that BACT requires applicant to

[4] This is the same DRAFT guidance Mr. Shepherd referred to in his presentation. The never-finalized Draft is internally inconsistent in some places.

install fuel-oil fired facility instead of the proposed coal-fired facility because requiring petitioner's "preference as to the type of boiler *and fuel to be used* . . . would in effect redefine the source") (emphasis added); *cf. In re Hibbing Taconite Co.*, 2 E.A.D. 838, 842-43 (Adm'r 1989) (finding that requiring an applicant to *continue* using natural gas instead of allowing it to switch to residual petroleum coke would not redefine the source).

Similarly, the vast majority of states that have considered the issue have determined that IGCC need not be considered in the BACT analysis because to do so would redefine the source. For example, two states, Utah and Georgia, recently considered whether IGCC should be included in the BACT analysis for a CFB unit or a PC unit. Both states concluded that PSD did not require consideration of an IGCC when the applicant had proposed a different power generation technology. *In re Sevier Power Company Power Plant,* DAQE-AN2529001-04, (UAQB Jan. 2008); *Friends of the Chattahoochee v. Couch*, OSAH-BNR-AQ-0732139-60-Howells, 2007 Ga. ENV LEXIS 60 (OSAH Dec. 18, 2007). They concluded that consideration of IGCC would redefine the source, which is not required by BACT. They also concluded that IGCC was not an "available" control technology for either a CFB or a PC. Other states which have taken this position include entucky, North Carolina, Missouri, Texas, Montana, Wisconsin and Nevada. Only Illinois and New Mexico have required consideration of IGCC in the BACT analysis. The only state to make that comparison, Illinois, determined that IGCC offered no benefit over pulverized coal and would cost significantly more. Hence it rejected IGCC in step two of the top down BACT process. This decision was upheld by EPA's Environmental Appeal Board. See *In re Prairie State Generating Co.*, PSD Appeal No. 05-05, slip op. at 46- 47 (EAB August 24, 2006). No state has determined that IGCC is BACT.

Most importantly DEQ has developed guidance on permitting, *VDEQ, Air Permitting Guidelines for New and Modified Sources*, January 5, 1996. It is posted on the State Air Pollution Control Board's website. That guidance incorporates the EPA Draft NSR manual by reference. The Draft NSR manual is the first articulation of EPA's policy that BACT does not redefine the source. This is a policy from which neither DEQ nor its predecessors have deviated. *See, In re SEI Birchwood, Inc. and In re Old Dominion Electric Cooperative, supra*. Where an agency pronounces a policy and follows it in long term practice, it may not deviate from it without undergoing a rulemaking or legislative change. This is the principle of Fair Notice recognized under the Due Process Clause. An agency may not exercise its discretion without taking into account a party's legitimate reliance on prior interpretation. Per this precedent, the length of time a particular interpretation has been allowed to stand indicates the General Assembly's accession to that interpretation:

> the practical construction given to a statute by public officials, and acted upon by the people, is not only to be considered, but, in cases of doubt, will be regarded as decisive. It is allowed the same effect as a course of judicial decision. The legislature is presumed to be cognizant of such construction, and, when long continued, in the absence of legislation evincing a dissent, the courts will adopt that construction. City of Norfolk v. Bell, 149 Va. 772, 780-81 (1928), citing Anable v. Commonwealth, 24 Gratt. (65 Va.) 563, 566; Lewis v. Whittle, 77 Va. 415, 422; Mangus v. McClelland, 93 Va. 786, 789.

Thus, per the view of the Virginia courts, if a rule construction is longstanding, and the General Assembly has not attempted to alter or amend it, the General Assembly has effectively approved the construction by its silence.

B. The Applicant De ines the ource.

As for how the "source" gets "defined" in the first instance and *who* is responsible for "defining" it, EPA's Environmental Appeals Board ("EAB") recently answered this key question. *See In re Prairie State Generating Co*. (EAB Aug. 24, 2006). The EAB concluded that "the statute contemplates that the permit issuer looks to how the *permit applicant* defines the proposed facility's purpose or basic design in its application," at least where "that purpose or design is objectively discernable." *Id.* slip op at 28 (emphasis added). The EAB further stated, the

> permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility, and therefore, the permit issuer must discern which design elements are inherent to that purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility.

Id. slip op at 30. Thus, according to the EAB, "the permit applicant initiates the process and, in doing so, we conclude, defines the proposed facility's end, object, aim, or purpose that is the facility's basic design." *Id*. slip op.at 29.

Dominion has defined the goal, aim and objective of the Project as building a base-load power plant designed to consume local Virginia coal. As indicated in the application, the "proposal has as its foundation legislation that was enacted by the Virginia legislature to create an incentive for the development of a power generation plant in the southwestern region of the state burning coal mined in Virginia." Application at 1-1. Given the fuel to be used, circulating fluidized bed ("CFB") was selected as the best available combustion technology.

C. Consideration o CC ould Rede ine the ource.

As discussed in Appendix E of the Application, an IGCC facility bears little resemblance to a CFB facility. CFBs utilize coal directly as a fuel for steam generation, which is subsequently used in a steam turbine/generator to generate electricity. IGCC plants on the other hand use coal as a feedstock in a chemical conversion process which, among other things, generates synthetic natural gas which is subsequently combusted in a gas turbine. As EPA Region 8 found: "Coal gasification is more akin to technology employed in the refinery and chemical manufacturing industries than technologies generally in use in power generation (i.e., a controlled chemical reaction versus a true combustion process)." Region 8 Response at 15.

Given these differences, requiring the consideration of IGCC technology in a BACT analysis for a proposed CFB unit would "redefine" the source in contravention of the CAA. For its part, EPA has repeatedly reached the same conclusion. EPA Region 8 concluded for Deseret that the "fundamental differences in equipment design [between gasification and boiler processes] are sufficient to conclude that the IGCC process would redefine the proposed source." Region 8 Response at 16; *see also* Letter from S. Page, Director EPA OAQPS, to P. Plath, E3 Consulting (Dec. 15, 2005) (hereafter "OAQPS Letter").

EPA's reasoning is reflected in the Region 8 decision, the Prairie State decision, and the OAQPS letter is consistent and well supported. Taking note of the statutory definition of BACT set forth in CAA § 169(3), EPA observed that "Congress distinguished 'production processes and available methods, systems and techniques' that are potentially applicable to a particular type of facility and should be considered in the analysis of BACT" from "alternatives" to the proposed source that would "wholly replace the proposed facility with a different type of facility." OAQPS Letter at 2. It is "often not clear," EPA continued, when "another production

process should be considered to fit within the BACT definition and when it should be considered an alternative to the proposed source." *Id.* This distinction is "especially difficult to make for coal gasification," EPA said, because the "definition of BACT includes 'innovative fuel combustion techniques' in a list of examples of production processes or available methods, systems, or techniques to be considered in the BACT analysis." *Id.* Nevertheless, "even assuming that coal gasification were in all respects an innovative fuel combustion technique for producing electricity from coal," the Agency did not believe that "Congress intended for an 'innovative fuel combustion technique' to be considered in the BACT analysis when application of such a technique would redesign the proposed source to the point that it becomes an alternative type of facility." *Id.*[5]

The combustion of this "cleaned" syngas in a turbine bears greater similarity to natural gas combustion than it does to any type of coal-fired boiler/steam electric generating unit. It has long been undisputed that an applicant proposing a coal-fired plant is not required to consider a natural gas fired plant. *In re Old Dominion Electric Cooperative*, 3 E.A.D. 779 (EAB 1992).

These differences in the fundamental processes between an IGCC and CFB also make the performance of a traditional top-down BACT analysis on a pollutant-by-pollutant basis difficult if not impossible and meaningless. Unlike an add-on control technology, which can be evaluated and compared on a pollutant specific basis, it is all or nothing with an IGCC or CFB. An applicant would not propose an IGCC for one pollutant and then select a CFB for another. The

[5] Subsequent to its issuance of the OAQPS letter, EPA acknowledged that the views expressed therein did not constitute binding legal policy sufficiently "final" to warrant judicial review. At the same time, the Agency's reasoning on this subject is persuasive and consistent with EPA Region 8's consideration of IGCC and long-standing EPA policy with respect to "redefining the source."

two technologies are mutually exclusive. Thus a requirement to use IGCC would impermissibly redefine the source.

D. BACT loo s to Demonstrated Technologies

Per the definition of BACT, technologies considered in the BACT analysis are those that are available and demonstrated. *See, e.g., Prairie State*, slip op. at 45. To be commercially available, a technology must be offered for sale through commercial channels. *Id.* BACT does not require an applicant to employ technologies that are not proven to work (i.e., not demonstrated). Theoretical, experimental or developing technologies are not "available" under BACT. Technologies with questionable or dubious reliability are likewise not considered "available" under BACT. *See In re Cardinal FG Co.*, 12 E.A.D. 153, 166-67 (EAB 2005) (finding the unpredictable effect that a technology would have on process a rational basis for concluding technology was infeasible). Moreover, by definition, technologies that are viable only with government subsidies are not commercially available. No IGCC has been proposed or built without reliance on substantial government subsidies, including the proposed Duke Edwardsport IGCC in Indiana.

BACT does not require the consideration of innovative control technology, such as IGCC.[6] Indeed, under the Board's regulations, use of innovative control technology is governed by special provisions. *See* 9 VAC 5-80-1825. An applicant must request in writing approval to use an innovate technology and, based upon that request the Board may only allow the use of the technology with consent from the governor(s) of affected state(s) and if specific conditions

[6] The definition of BACT does include consideration of "innovative combustion techniques." 9 VAC 5-80-1615(C). IGCC is not an innovative ***combustion*** technique. The combustion technique of IGCC is the traditional combined cycle plant.

are met. *Id*. By definition, innovative technologies do not qualify as either available or demonstrated under BACT. 9 VAC 5-80-1615(C).

E. BACT evaluates achievable emission limits

Consideration of IGCC in a BACT analysis presents another problem. According to the definition of BACT, a BACT limit must be "achievable." "Achievable" in the context of BACT means an emission limit that the source can meet on a continual basis for the lifetime of the facility. *See In re Newmont Nevada Energy Investment, LLC*, 12 E.A.D. 429, 442 (EAB 2005). Since none have been built, much less operated, no one knows what the new generation of IGCC can achieve on a consistent basis in the short term, much less over its lifetime. BACT is not established based on speculation or what may theoretically be possible. Accordingly, a BACT analysis does not require an applicant or the permitting agency to speculate about what a technology ***might*** be able to achieve in the future. *See, e.g., In re Cardinal*, 12 E.A.D. at 166 (upholding permitting agency's rationale that 2 to 3 years operating history of a technology "is insufficient to satisfy the concept of demonstrated technology" when the issue is the full life of the unit).

The BACT analysis "must be solidly grounded on what is ***presently known*** about the selected technology's effectiveness" and "emissions limitations achieved by other facilities and corresponding control technologies used at other facilities are an important source of information in determining" BACT. *Newmont*, 12 E.A.D. at 441 (emphasis added). In the context of IGCC, this absence of data would suggest ignoring it in the BACT process. In reaching its conclusion in *Newmont*, the Board considered its previous decisions relating to the stringency of the emission rate required by BACT (*see, e.g.*, *In re Kendall New Century Dev.*, 11 E.A.D. 40 (EAB 2003); *Cardinal*, 12 E.A.D. 153; *In re Steel Dynamics, Inc.*, 9 E.A.D. 165 (EAB 2000); *In re*

Three Mountain Power, L.L.C., 10 E.A.D. 39 (EAB 2001)). The Board summarized those opinions as standing for the proposition that "if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the 'emissions limitation' that is 'achievable' for that pollution control method over the life of the facility." *Newmont*, 12 E.A.D. at 442.

. **BACT has to be practical**

Finally, to require consideration of IGCC technology in a BACT analysis for a CFB would result in an IGCC "apples" to a CFB "oranges" comparison. Under the "top down" methodology typically employed in a BACT analysis, an applicant is required to identify the technically feasible technologies that apply to the proposed source. Requiring the consideration of IGCC technology at this stage of the analysis immediately presents problems, in that the characteristics of that technology are unlikely to match the characteristics of the proposed source.

The "top down" methodology then requires that feasible technologies be ranked in descending order of their expected effectiveness. The top technology must be selected to control emissions of a pollutant unless it is shown that energy, environmental, or economic impacts, justify elimination of that technology. If the most stringent technology is eliminated in this fashion, then the next most stringent technology is considered, and so on, until the best available technology for the proposed project is selected. *See ADEC v. EPA*, 540 U.S. 461, 475-76 (2004), quoting EPA's "NSR Manual."

The simple practicality of assessing economic impacts from the consideration of IGCC in a BACT analysis as compared to CFB is difficult. In a normal BACT analysis, the common economic measuring stick is the "cost per ton removed" of a specific pollutant for each technology under consideration. To evaluate on a pollutant specific basis to compare an IGCC

unit to a CFB unit, the analysis would have to include the cost of the entire IGCC facility with its add-on control versus the cost of the CFB facility with its add-on controls, as the two types of facilities are mutually exclusive. Additionally, in trying to account for the overall capital cost, operating cost and lower reliability impacts on project economics, the "cost per ton removed" measuring stick is not sufficient. The more accurate economic assessment approach will need to define significant cost impacts on the total cost of generation itself, which is not done in a BACT context, but in an applicant's economic assessment of technology alternatives.

More concretely, BACT is not a technology but an emission limit for a particular pollutant. While it is not the case today based on currently operating IGCC units, it is conceivable that one day lower limits might be demonstrated for an IGCC for some pollutants, but not others. This would pose a dilemma because, unlike add-on technology, IGCC is fundamentally different from in fact, incompatible with CFB technology. Thus, a permit writer would have to decide which technology is BACT and which pollutant should be controlled over others. BACT does not contemplate such a result or process. This is further support for the position that IGCC should not be considered in the BACT analysis for a CFB.

. **Authority o the DEQ and the Board to consider alternative sites, technology, control, uels, uel characteristics, uel cleaning and preparation, emission limits and operating restrictions ith respect to VCHEC**

In light of the above discussion there are limitations on the authority of the Board and DEQ to consider alternatives to the listed parameters --"sites, technology, control, fuels, fuel characteristics, fuel cleaning and preparation, emission limits and operating restrictions" -- as applied to VCHEC. These limitations are listed below for each of these parameters.

Alternative ites

- In approving permits, the Board and DEQ shall consider the suitability of the activity in the area in which it is located. Va. Code § 10.1-1307. E.3

- That language does not expressly authorize the Board to consider alternative sites -- rather it authorizes consideration of the suitability of the proposed site.

- The General Assembly and the Board have implemented this criterion by requiring as part of the permit application process that local governments certify that the propose source will comply with applicable local ordinances. Va. Code § 10.1-1321.1; 9 VAC 5-80-1665. The Board has also adopted a written policy in which it states it will leave the question of suitability to the local government. in the case of VCHEC, Wise County has provided the necessary certificate.

- The General Assembly has also found that a coal fired power plant located in the coalfield region of Virginia is in the public interest. Va. Code § 56.585.1.A.6.

- Base on the above, the General Assembly has limited the Board's authority to consider alternative sites and based on applicable law and longstanding Board policy, if Wise County finds that the project meets applicable local requirements and it has in the case of VCHEC, that is the end of the Board's inquiry into site selection.

Alternative Technology and Control Technology

- In approving permits the Board and DEQ are authorized to consider the social and economic value of the activity involved (Va. Code § 10.1-1307. E.3) and the scientific and economic practicality of reducing or eliminating the discharge resulting from such activity (Va. Code § 10.1-1307. E.4).

- This analysis of technology that is traditionally performed is the BACT analysis pursuant to the requirements of 9 VAC 5-80-1705. B. and the definition of BACT in 9 VAC 5-80-1615.

- The BACT process evaluates the "proposed" source -- i.e. the Source as defined by the applicant. There is a long line of decisions, based on the applicable statutory and regulatory language, by EPA and Virginia that the BACT process does not redefine the source. *See, e.g. In re SEI Birchwood Inc*., 5 E.A.D. 25 (1994); *In re Old Dominion Electric Cooperative* 4 E.A.D. 779 (1992) (permit issued by the State Air Pollution Control Board under delegation from EPA for a coal-fired power plant did not require consideration of natural gas fired turbines in the BACT analysis because that is fundamentally different process and to require such consideration would redefine the project).

- The goals, aims and objectives of Dominion in constructing VCHEC are to build a coal fired power plant located in the coal field region of Virginia, burning Virginia coal, waste coal and biomass. As explained in Attachment 1, CFB is the only technology that can handle this wide range of fuels. Consistent with the findings of EPA with respect to Deseret, given the fuels, IGCC would be inconsistent with the goals, aims and objectives of VCHEC. It would

impermissibly redefine the VCHEC project. *See In re Prairie State* slip op at 20-21.

- Aside from the fuels issue, other permitting agencies have determined that consideration of IGCC as an alternative for a CFB boiler would impermissibly redefine the project. Specifically EPA Region 8 concluded for Deseret Power Station that the "fundamental differences in equipment design [between gasification and boiler processes] are sufficient to conclude that the IGCC process would redefine the proposed source." Region 8 Response at 16; *see also* Letter from S. Page, Director EPA OAQPS, to P. Plath, E3 Consulting (Dec. 15, 2005) (hereafter "OAQPS Letter").

- As with consideration of alternative technologies and controls, in evaluating control technologies, the BACT process looks at technologies that are "available" and demonstrated. IGCC has not demonstrated the reliability necessary for a base load power plant. (See Attachment 1). Vendors have not offered the terms necessary to make it commercially available and no IGCC plant has been built or proposed without government subsidies. Therefore IGCC is not yet an available technology.

Alternative uels and uel Cleaning

- Consideration of fuels arguably invokes all four of the criteria set out in Va Code § 10.1-1307 E. With respect to Va. Code § 10.1-1307 E.1., fuels can affect emissions and therefore air quality and therefore public health and safety and welfare. Virginia addresses this through the air quality modeling performed to demonstrate compliance with applicable requirements pursuant to 9 VAC 5-80-1715, 1755 and 1765. VCHEC has met all criteria under these regulations so no further inquiry into alternatives is warranted or authorized.

- With respect to Va Code 10.1 1307.E. 2. and 3., the economic and social value of using the propose Virginia coal and the proximity of the plant to that fuel have been found by the Virginia General Assembly to be in the public interest. The purpose cited by the General Assembly, to promote a reliable supply of energy and to promote economic development also supports the use of run of mine rather than the high quality coal that will be used in any event as explained further in Attachment 3. Moreover, Article XI, Section 1 of the Virginia Constitution states:" *it shall be the policy of the Commonwealth to conserve, develop, and utili e its natural resources*". As also explained in Attachment 3, this is best achieved by burning run of mine coal in a CFB rather than high quality coal in an IGCC. Given the proposed projects consistency with the intent of the General Assembly and the Virginia Constitution, no further inquiry into alternatives is required or justified.

- With respect to Va Code§ 10.1 E.4. fuels and fuel cleaning are alternatives to be considered in the BACT analysis. The permit application and other previous submittals have addressed fuels and it is further evaluated in Attachment 3. We note again that use of Virginia coal, waste coal and biomass are part of the goals, aims and objectives of the project which BACT does not redefine. 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.

Alternative emission limits and operating restrictions.

- In approving permits the Board and DEQ are authorized to consider scientific and economic practicality of reducing or eliminating the discharge resulting from such activity (Va. Code § 10.1-1307. E.4).

- This analysis of technology that is traditionally performed is the BACT analysis pursuant to the requirements of 9 VAC 5-80-1705. B. and the definition of BACT in 9 VAC 5-80-1615. In fact, the definition of BACT is structured in two parts, the first concerns the establishment of emission limits and the second concerns the establishment of operating restrictions where emission limits are infeasible.

- Therefore all of prohibitions and restrictions on the BACT analysis apply here as well. BACT does not redefine the source as proposed by the applicant and BACT only looks at emission limitations and operating restrictions that are feasible, available and demonstrated.

- There have been suggestions that in evaluating alternative technologies or setting emission limits in the BACT analysis it is appropriate to look at what proposed projects, most of which have been cancelled, might have achieved. BACT evaluates only "achievable" emission limits. According to the definition of BACT, a BACT limit must be "achievable." "Achievable" in the context of BACT means an emission limit that the source can meet on a continual basis for the lifetime of the facility. *See In re Newmont Nevada Energy Investment, LLC*, 12 E.A.D. 429, 442 (EAB 2005). Since none have been built, much less operated, no one knows what the new generation of IGCC can achieve on a consistent basis in the short term, much less over its lifetime. BACT does not look at what might be achieved in the future, rather the BACT analysis "must be solidly grounded on what is presently known about the selected technology's effectiveness" and

> "emissions limitations achieved by other facilities and corresponding control technologies used at other facilities are an important source of information in determining" BACT. *Newmont*, 12 E.A.D. at 441. Thus, it is not appropriate to consider next generation IGCC units in the BACT analysis for a CFB unit.

In sum, reading the applicable laws granting authority to the Board together with the Virginia regulations that have been used to implement that authority and statute promoting construction of a plant burning Virginia coal in the southwest Virginia coalfields, the practical authority to consider the listed alternatives is limited to that already performed in developing the draft PSD permit. Therefore no other consideration of such alternatives is required or authorized.

ATTACHMENT 2

Introduction

Dominion Energy (Dominion) requested that CH2M HILL prepare an analysis of the cost-effectiveness of alternative power generation technologies for the air permitting process for the Virginia City Hybrid Energy Center (VCHEC). This analysis would evaluate the incremental cost per ton of emissions reduced when comparing the circulating fluidized bed (CFB) technology selected for VCHEC with a hypothetical Integrated Gasification Combined Cycle (IGCC) unit using the VCHEC design fuel, and a hypothetical Supercritical Pulverized Coal (SCPC) unit using cleaned eastern bituminous coal.

Disclaimer

It is important to note that this analysis is based on using the VCHEC design fuel in a hypothetical IGCC unit. As the discussion below shows, the VCHEC design fuel is technically unacceptable for use in IGCC power generation technology. For the purposes of this analysis, the costs and operating characteristics of a "hypothetical IGCC unit" were estimated. In no way does this hypothetical analysis validate the potential for design or operation of IGCC power generation technology with the VCHEC design fuel.

EPA guidance does not require a BACT analysis to be done for power generation facilities that use fundamentally different combustion processes. CFB and SCPC are combustion processes that produce only steam for use in a steam turbine generator for the production of electricity. IGCC uses a gasifier to produce synthesis gas for combustion in gas turbines that produce electricity. Waste heat from the gas turbine exhaust is used to make steam for additional power generation. Thus, CFB and SCPC, when compared to IGCC, are fundamentally different power generation processes and EPA guidance does not require that they be compared in an analysis such as this. However, in response to a

Virginia State Air Pollution Control Board inquiry, the alternative power generation technology analysis has been prepared.

Results

The results of the cost-effectiveness evaluation, presented as the incremental emission control cost, in $/ton removed, for replacing the CFB technology with the hypothetical IGCC technology and the hypothetical SCPC unit are shown below in Table 1. Since CFB, SCPC and IGCC are power generation technologies, and not emission control technologies, the only way to achieve individual emission reductions would be to completely replace the CFB unit with the hypothetical IGCC unit or hypothetical SCPC unit (versus substituting only emission control systems as is the purpose of the BACT analysis). Therefore, the incremental costs are a function of the overall higher capital and operating costs of IGCC and SCPC technologies compared to the CFB technology.

These costs per ton controlled were derived by computing the increased annual costs individually for the hypothetical IGCC and hypothetical SCPC options over the CFB option and dividing the differences by the annual reduction in emissions compared to the CFB option. Changing from the CFB technology selected for VCHEC to the either the hypothetical IGCC or hypothetical SCPC technology would not be cost effective.

Table 1. Emission Reduction Costs for IGCC and SCPC vs. CFB

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Technology Descriptions

Dominion has previously provided the Virginia Department of Environmental Quality (DEQ) with detailed descriptions of CFB, IGCC and SCPC power generation technologies. Those detailed discussions will not be repeated here. However, it is important to understand the main distinguishing characteristics of each of these power generation technologies. For CFB and SCPC, the coal is the "fuel". For IGCC, the coal is the feedstock for the chemical conversion process producing syngas that becomes the actual "fuel", which is cleaned and then combusted in gas turbines.

While CFB and SCPC actually combust the coal, the gasification process used in IGCC power plants does not. Gasification is a chemical conversion process that converts the carbon and moisture in the coal (or other feedstock or blend of feedstocks) into a synthetic gas (syngas) composed primarily of carbon monoxide, hydrogen, water, carbon dioxide and methane. In modern gasifiers used in IGCC power plants, this conversion process occurs at temperatures of 2,500-2,900°F and pressures of 400 psi or greater, using only a small fraction of the air or oxygen that would be needed to

combust the coal. While CFB boilers require excess air in order ensure complete combustion of the carbon in the coal, IGCC is "oxygen-starved".

Combustion in SCPC boilers involves first crushing and pulverizing the coal particles to the consistency of powder, and then blowing the coal powder into the boiler through specially designed burners. SCPC technology is commercially available for a wide range of domestic coals, including bituminous, subbituminous and lignite. While each individual unit must be designed for a narrow range of fuels, SCPC technology would not be suitable for a fuel mix such as that proposed for the VCHEC facility (run-of-mine (ROM), gob, and biomass). The size of the boiler is dependent on the type of coal used. High quality bituminous coals are able to burn quickly, with short residence times. Lower quality subbituminous and lignite coals take longer for the carbon to burn out, due to their higher content of moisture and lower amounts of volatile matter with a high heating value. Boilers designed for lower quality coals must provide additional residence time for complete burnout, and are larger (typically taller) than those designed for bituminous coal.

Further, ash content has detrimental effects on the combustion in SCPC boilers. As ash content increases, the fixed carbon and volatile matter contents of the coal necessarily decreases. Since ash does not combust, higher ash content results in lower heating value. For low volatile matter and high ash coals, SCPC technology does not provide sufficient flame stability, residence time or carbon burnout.

As Dominion has previously described, CFB technology is ideal for the combustion of low quality fuels, as it provides long residence time in the fluidized bed, assuring carbon burnout. CFB technology is proven worldwide for use with low quality fuels. Information submitted by Dominion to the DEQ provides the following analysis for the low quality fuel to be used at VCHEC:

The coal for this project consists of (1) run-of-mine Virginia coal with an average heating value of 7,7 2 Btu lb and a maximum ash content of 44 and (2) waste coal with a heating value of 2,7 Btu lb and a maximum ash content of 71.5 .

This combination of high ash, low volatile matter, and low heating value makes the coal unacceptable for use in a SCPC boiler. These characteristics are even worse for the waste coal. As Dominion has previously discussed, CFB technology is the best choice for efficiently and effectively combusting the coal and/or waste coal to be used for VCHEC.

IGCC Technology

Impacts of Coal Quality on IGCC Design and Performance

Since the purpose of a gasifier is to convert carbon to syngas, the higher the carbon content in the feedstock, the higher the conversion of the feedstock to syngas. Gasifiers work more efficiently with high-carbon feedstocks, such as bituminous coal (typically 70 carbon) and petroleum coke (typically 80 carbon), although volatile matter adds to the overall reactivity of the feedstock because it can gasify faster than carbon. The lower the quality of the coal (higher ash and moisture content), the less efficient the gasification conversion process. Coal quality is directly impacted by the ash and moisture content of the coal. As ash and moisture content increase, carbon content necessarily has to decrease, further reducing the heating value (in Btu/lb) and quality of the coal.

High fuel ash content is a drawback for all gasifiers. In the gasifier, the ash must be heated to gasification temperature by burning fuel, usually with pure oxygen, so it represents a thermal loss to the system (reduced plant efficiency). At the high temperatures of oxygen-blown gasification, the ash is converted to a molten slag, which then flows from the bottom of the gasifier into a water bath. There, the slag is quench-cooled and it solidifies into a black, glassy material. For refractory-lined gasifiers, some amount of slag is needed to protect the hot face of the refractory. However, as ash content increases, more slag results in higher erosion rates for the refractory, resulting in a shorter

life, more required maintenance and earlier replacement. Replacement of refractory is not only expensive, but it takes considerable time so that the downtime for replacement directly impacts IGCC plant availability.

For gasifiers with membrane walls, a minimum ash content is necessary in order to provide an insulating, protective coating to the tubing. Below that value, heat loss increases and the surface temperature of the membrane wall may become too high, risking high temperature corrosion. The gasifier industry uses a guideline of about 5 ash (dry basis) minimum for gasifiers with membrane walls. However, the higher the ash content, the greater the impacts on gasifier performance and heat transfer.

For all types of gasifiers, the higher the ash content of the feedstock, the greater the design capacity of the ash and slag handling systems. This increases cost and complexity, as well as reducing the overall efficiency as noted above. More ash means more slag, and the slag handling equipment experiences more maintenance and replacement due to the erosive and corrosive nature of the slag. Along with coal handling equipment, ash/slag removal and handling equipment is the most troublesome equipment in an IGCC plant.

The U.S. Environmental Protection Agency (EPA) addressed low quality coal use in IGCC plants in its report entitled "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies," EPA-430/R-06/006, July 2006. In this report, EPA noted that "relatively little research or commercial work has been done to investigate gasification of low rank coals, including subbituminous and lignite, for electric generation purposes." The two IGCC plants currently operating in the U.S., Wabash River Generating Station (Indiana) and Polk Power Station (Florida) were designed for high heating value, low ash content, eastern bituminous coals. The Wabash River Generating Station now uses up to 100 petroleum coke as its feedstock. Polk Power Station uses a blend of up to 60 petroleum coke with 40 bituminous coal. The use of petroleum coke as an opportunity feedstock was initiated after several years of operation on coal, and after considerable testing of different coal/petroleum coke blends.

Gasifiers do have some feedstock flexibility, meaning that they may be able to operate with off-design feedstocks. However, when using lower grade feedstocks, performance, carbon conversion, and overall efficiency are reduced. Note, however, that the "off-design" feedstocks now utilized at both Wabash River Generating Station and Polk Power Station are higher quality feedstocks, not lower quality feedstocks. Further, gasifiers (and the balance of the entire IGCC plant) operate best when the feedstock quality is stable. Radical changes in feedstock characteristics lead to changes in slurry concentration, changes in gasifier temperature (and therefore changes in conversion of the carbon to syngas), and changes in the response of particulate and sulfur removal systems. Further down stream in the process, the gas turbine then experiences a different syngas quality, which changes its performance. The fuel supply for the VCHEC facility includes a mix of fuels ranging from ROM coal to waste coal to biomass.

Experience with Low Rank Coals in Gasifiers

Presently, there are only two operating electric utility coal-based IGCC facilities in the United States. Both were designed to use eastern bituminous coal. Several non-utility IGCC demonstration plants (which were later dismantled) and one commercial coal gasification plant (not IGCC) were designed to use low rank subbituminous or lignite coals. None were designed to use the type of fuels and fuel mix planned for VCHEC. Following is a discussion of some of these facilities.

Gasifiers can be designed for lower grade coals, such as subbituminous and lignite. Subbituminous coal (about 30 moisture) from the Powder River Basin (PRB) in Wyoming was used in the Louisiana Gasification Technology, Inc. (LGTI) demonstration plant in Plaquemine, Louisiana from 1987-1995. Almost 4 million tons of this coal was successfully gasified during the demonstration period. This technology is now commercially available as the E-Gas technology offered by ConocoPhillips. Note however, that PRB coal typically has a carbon content of 45-50 , a heating value in the 8,300-8,800 Btu/lb range, and an ash content of 6 . The ash content is far lower than for the design fuel for VCHEC.

During this same timeframe, Shell demonstrated its Shell coal gasification technology at its Deer Park facility in Texas. This demonstration plant tested a wide variety of feedstocks, from low quality Texas lignite to high quality petroleum coke. Texas lignite typically has carbon content of 35 , a heating value of about 6,000 Btu/lb, and an ash content of about 15 . Again, even this lignite is considerably lower in ash content than the design fuel for VCHEC.

The Great Plains Gasification facility in Beulah, North Dakota has been gasifying North Dakota lignite for over 25 years, converting the syngas to synthetic natural gas for sale. The facility uses fixed-bed Lurgi gasifiers, which operate at lower temperatures than the entrained-flow gasifiers used in modern IGCC plants. The lignite, mined locally, has a carbon content of about 45 , heating value of 6,900 Btu/lb, and an ash content of 6.5 . It is a high moisture coal, with a moisture content of 37 . The high moisture, not the ash content, is what makes this lignite low in heating value. While this low quality coal is used successfully in a gasifier, it is also considerably lower in ash content than the design fuel for VCHEC.

Other gasifiers are being designed for low quality coals. The ellogg Brown & Root (BR) transport gasifier is being demonstrated at the Power Systems Development Facility near Wilsonville, Alabama, adjacent to one of Alabama Power Company's power plants. There, PRB coal has been successfully tested in this unique gasifier. Again, this is a low ash, high moisture subbituminous coal. The gasifier size is only about 4-6 MW equivalent. This gasification technology has not been demonstrated at large scale. A 550 MW (net) plant using the BR technology with Mississippi lignite is being planned by Mississippi Power Company. The Mississippi lignite that the plant expects to use will have an average analysis of 4,921 Btu/lb, 1 sulfur, 10.85 ash, and 38-40 moisture (as received basis). As with other modern IGCC systems, it is necessarily being designed for low ash content coal.

GE Energy is an active developer and technology supplier in the gasification and IGCC industry. At the 2007 Gasification Technologies Conference, a presentation provided by Mr. John Lavelle, General Manager, Gasification for GE Energy, provided information on the type of coal that the

GE gasification technology is designed to use. The GE gasification technology is designed for an eastern bituminous coal, with up to 14 ash. This further supports the fact that high ash coal is not technically acceptable for use in gasifiers used in modern IGCC plants.

ConocoPhillips is another leader in the gasification and IGCC industry. At the 2005 Gasification Technologies Conference, ConocoPhillips presented a paper entitled "Comparative IGCC Performance and Costs for Domestic Coals". This comprehensive study, which was performed for their E-Gas gasification technology, included design and cost information for petroleum coke, two types of bituminous coal, and PRB coal. No high ash coals were included in their study. This slurry-feed, refractory-lined gasifier technology is not designed to use high ash coals, for the reasons described above.

Clearly, the information provided herein demonstrates that high ash coals are technically unacceptable for IGCC technology. There is <u>no demonstrated IGCC experience with feedstocks similar to the design fuel for the VCHEC facility</u>.

Impacts of Coal Quality on IGCC Cost

While the information provided above demonstrates that the high ash content of the VCHEC design fuel makes it technically unacceptable for use with IGCC, it is important to consider potential cost impacts of using low quality feedstocks in IGCC power plants. Most of the IGCC plants being proposed at this time for operation in the 2011-2014 time period are based on the use of high quality (low ash) eastern, bituminous coal. One good example is Appalachian Power Company's proposed IGCC plant to be located at its Mountaineer Plant in West Virginia. The design coal for this plant, based on GE Energy gasification technology, is West Virginia bituminous coal, with a heating value of 12,808 Btu/lb and ash content of 11 .

Appalachian Power Company serves customers in West Virginia and Virginia. Therefore, it is required to obtain approvals for cost recovery from commissions in both states. While the West Virginia Public Service Commission approved the costs for the plant, the Virginia State Corporation Commission (SCC) did not. In its submittals to the SCC, Appalachian Power Company noted that the total installed cost of the IGCC plant would be "approximately $2.23 billion". With a net output of 629 MW, this calculates to be $3,545/kW (net), with operation planned in 2012.

Similar costs have been provided in publicly available information submitted for the following IGCC projects:

Duke Energy Edwardsport : $1.98 billion, or $3,150/kW (eastern bituminous)

Excelsior Energy, Mesaba Project (delayed): $2.156 billion, $3,594/kW (blends of eastern bituminous, PRB and petroleum coke)

Tampa Electric Company, Polk Power Station Unit 6: (cancelled): $2.0 billion, or $3,180/kW (blends of eastern bituminous and petroleum coke)

This shows a range for IGCC technology of $3,150-3,594/kW. The Mesaba IGCC project is higher in cost, particularly due to design considerations for the PRB coal, which requires substantially more coal throughput due to the lower heating value of PRB coal. Therefore, the coal storage, handling and coal slurry preparation systems are larger than those for IGCC plants designed only for eastern bituminous coals (alone or blended with petroleum coke).

The presentation by ConocoPhillips (noted above) provides cost comparison information for the various types of feedstocks. On average, an IGCC plant designed for low quality PRB coal would cost about 30 more than for one designed for bituminous coal. Some of that cost increase is due to the higher amount of coal throughput required, since PRB coal has a heating value of about 2/3 that of bituminous coal. Put another way, the PRB-based IGCC plant would require 50 more coal throughput, resulting in larger, more expensive coal handling and slurry preparation systems. No information is provided for the cost multiplier for using a high ash coal, since that is neither technically feasible nor commercially available for IGCC.

For the purposes of this hypothetical cost-effectiveness analysis, the hypothetical IGCC plant would be designed to use low quality coal. The cost multiplier would be at least that for using PRB coal. Therefore, the Appalachian Power Company IGCC plant would cost at least $2.9 billion, or $4,610/kW (net) if it could be designed to use low quality PRB coal. Additional cost impacts would result from design changes to handle the lower heating value and higher ash VCHEC design fuel.

The Appalachian Power Company IGCC plant is designed to use 5,621 tons/day of bituminous coal, producing 618 tons/day of slag. Using a PRB coal with a heating value of 8,300 Btu/lb and 5 ash would require 8,675 tons/day of PRB coal, producing 434 tons/day of slag. Therefore, the coal handling and preparation system for PRB coal would need to be increased in size by 54 over that for the eastern bituminous coal. Using the VCHEC design fuel heating value of 7,782

Btu/lb and ash content of 44 , the hypothetical IGCC plant would require a throughput of 9,316 tons/day of coal and would produce 4,100 tons/day of slag. This would require an increase of 66 in coal throughput (compared to using eastern bituminous coal) with significant increases in the size and cost of the coal handling and slurry preparation systems. The ash handling system would need to be increased in size by over 500 . The 30 capital cost multiplier would need to be further increased for the hypothetical IGCC plant using the VCHEC design fuel instead of PRB coal. For this hypothetical analysis, a 35 capital cost multiplier (compared to an IGCC plant designed for eastern bituminous coal) will be used.

Therefore, the capital cost of the hypothetical IGCC plant designed to use the VCHEC fuel would be at least $3 billion, or $4,786/kW (based on a 629 MW net plant). Scaling the IGCC plant size down to 585 MW (net) output at the same $/kW value, the cost of the hypothetical IGCC plant at VCHEC would be $2.8 billion.

The VCHEC plant is estimated to cost $1.8 billion for 585 MW (net). Therefore, the hypothetical IGCC plant would cost 55 more than the CFB technology selected for VCHEC.

This analysis will use the annual emissions provided by Appalachian Power Company, reduced proportionately from 629 MW (net) to 585 MW (net), for the hypothetical IGCC plant.

Annual Costs

It is impossible to precisely determine the annual O&M costs for a hypothetical IGCC unit using a feedstock that is unacceptable for use in it. The U.S. Department of Energy's report "Cost and Performance Comparison of Fossil Energy Power Plants", May 2007, provides detailed estimates for O&M costs for IGCC plants using eastern bituminous coal. For the GE Energy-based IGCC plant example in the report, total fixed operating costs are $22.6 million/year, and total variable operating costs are $22.1 million/year. Total O&M costs are $44.7 million/year. Of course, actual O&M costs would be much higher, especially in the slag handling and disposal system sizes and costs. Due to the significantly higher ash erosion and corrosion impacts, refractory and piping system replacements would be much more frequent and much more expensive. For this analysis, we are using these costs on an unadjusted basis, but would expect them to be significantly higher.

Fuel Costs

For the purposes of this analysis, the VCHEC design fuel will be utilized for the hypothetical IGCC unit cost-effectiveness calculations. Per Dominion Energy, the fuel cost is $3.19/MMBtu.

SCPC Technology

Dominion has previously provided detailed technical descriptions of SCPC technology to DEQ. As noted above, the coal and waste coal which will be the fuels for VCHEC are unacceptable for use in a SCPC boiler. A SCPC boiler does not provide sufficient residence time for a high ash, low volatile matter coal to completely combust.

Impacts of Coal Quality on SCPC Design and Performance

SCPC boilers are designed to combust carbon. It is the carbon content that provides the primary heating value of the coal. Carbon exists in two main forms in coal: fixed carbon and volatile matter. The volatile matter is important in maintaining flame stability and quick burnout of the fixed carbon. As the moisture and ash contents of the coal increase, the total carbon content necessarily decreases, and the heating value of the coal is reduced. As noted above, lower quality coals require longer residence times for complete burnout, so that boilers designed for lignite are typically larger (taller) than those designed for subbituminous (PRB) coals, and they are larger than boilers designed for bituminous coals. While anthracite coal has very high carbon content, it is mostly in the form of fixed carbon, with little volatile matter. Because of this, anthracite is very difficult to ignite, and it is not typically used in PC boilers unless it is blended with other coals that provide the necessary volatile matter.

Higher ash content also reduces SCPC boiler combustion efficiency, since the ash can coat or “blind” carbon particles. In addition, boiler efficiency is reduced since part of the heat produced during the combustion process is used to heat the fly ash and bottom ash to furnace temperature. Much of this heat is then lost as the fly ash and bottom ash are

removed from the boiler for disposal. Therefore, higher ash coals require larger and more expensive fly ash and bottom ash handling systems for SCPC boilers. Combining the impacts from longer residence time requirements and increased ash production, SCPC boilers designed for lower quality coals are more expensive than those designed for bituminous coals.

High ash coals, such as the design fuel for VCHEC, have such poor characteristics that they are technically unacceptable for use in a SCPC boiler. The waste coal is even worse, and neither flame stability nor carbon burnout would occur. That is why a CFB boiler must be used for these low grade coals and waste coals.

Costs for SCPC Technology

A good example of SCPC technology designed for eastern bituminous coal is Santee Cooper's proposed Pee Dee Electrical Generating Station in South Carolina. The plant will have two 660 MW (gross)/600 MW (net) SCPC units. While detailed plants costs are not yet publicly available, this analysis will use the design characteristics of the Pee Dee units along with the estimated costs for a SCPC unit, as submitted by Appalachian Power Company as part of their economic analysis of the Mountaineer IGCC facility. In "Exhibit No. 4, rev. 1" of testimony submitted by Mr. Michael Renchek, Appalachian Power Company provided detailed estimates of the costs of various coal-based power generation technologies, based on several types of coal. The table notes the following costs for SCPC and IGCC technologies designed for eastern bituminous coal:

- IGCC: $2,861/kW
- SCPC: $2,189/kW

These values are year 2006 "overnight" capital costs and do not include interest costs during construction, nor escalation to the in-service year of the proposed plant of 2012. As noted above, Appalachian Power Company submitted a total installed cost value of $2.23 billion ($3,545/kW) to the Virginia State Corporation Commission. This value does include escalation to 2012 and does include interest costs during construction. Using that value, and applying this same ratio to the SCPC cost, the SCPC plant cost

estimate would be $2,712/kW in 2012. For 585 MW (net), the cost of the hypothetical SCPC plant would be $1.59 billion, for use with clean, bituminous coal.

Fuel Costs

For the purposes of this analysis, a cleaned, eastern bituminous coal would be the design fuel for the hypothetical SCPC unit. Per Dominion Energy, the cost of such coal is $4.21/MMBtu delivered.

Annual Costs

For this hypothetical analysis, annual O&M costs from the U.S. Department of Energy's report referenced above are used. Exhibit 4-35 of that report provides annual O&M costs for a SCPC unit designed for eastern bituminous coal. The total fixed operating costs are $13.85 million/year and the total variable operating costs are $19.95 million/year. Therefore, total O&M costs are $33.85 million/year.

Data Table

The table below presents the information to be used for the cost-effectiveness calculations. Sources of the data are noted below the table.

	Virginia City Hybrid Energy Center CFB[1]	Appalachian Power Company IGCC[2]	Hypothetical IGCC Plant[3]	Hypothetical SCPC[4]
MW gross	668	784	729	643.5
MW net	585	629	585	585
Capacity factor	90%	85%	85%	90%
Capital cost, $B	1.8	2.23	2.8	1.59
Capital cost, $/net kW	3,077	3,545	4,786	2,712
Heat rate, Btu/net kWh	9,377	9,539	9,539	9,500
SO_2, TPY	3,292.36	586.44	545	2,996
NOx, TPY	1,920.54	1,561.5	1,452.3	1,748
CO, TPY	4,115.45	943.7	877.7	3,745
VOC, TPY	137.18	83.35	77.5	60
PM (total), TPY	329.24	194.1	180.5	449
Total Emissions, TPY	9,794.8	3,369.1	3,133	8,998
Fuel cost, $/MMBtu	3.19	4.21	3.19	4.21

Table Notes:

1 – Data provided by Dominion Energy. Emission data from VCHEC draft permit.

2 – Unit ratings and costs from Appalachian Power Company submittals to West Virginia Public Service Commission. Emissions are from the permit application for the Mountaineer IGCC facility submitted to the West Virginia Department of Environmental Protection. Fuel cost is as provided by Dominion Energy for clean eastern bituminous coal.

3- Unit ratings are scaled based on the direct ratio of 629 MW net for the Mountaineer IGCC plant to the 585 MW net capacity for the VCHEC. Capital cost is based on a hypothetical IGCC plant as described above, designed for use of the VCHEC design fuel. This study assumes that regardless of coal, the emission would be the same for IGCC. To be more accurate, the annual emissions are scaled from the 629 MW net Mountaineer Plant to the 585 MW net level for the hypothetical IGCC plant.

4- Unit ratings are scaled based on publicly available information from Santee Cooper for its proposed Pee Dee Electrical Generating Station, which will use SCPC technology and is being designed for cleaned eastern bituminous coal. Capital cost is as calculated above, based on SCPC cost data provided in Appalachian Power Company's coal-based power generation technology comparison, which was submitted to the West Virginia Public Service Commission. O&M costs are per U.S. DOE report. Fuel cost is as provided by Dominion Energy for cleaned eastern bituminous coal. Emissions are from the draft permit for the Pee Dee Electrical Generating Station, issued by the South Carolina Department of Health and Environmental Control. For this analysis, it is assumed that the annual emissions would not change.