Powder River Basin Resource Council
Wyoming Chapter of Sierra Club
Wyoming Wilderness Association
Wyoming Outdoor Council
Biodiversity Conservation Alliance
Western Resource Advocates
Natural Resources Defense Council

March 27, 2007

David A. Finley, Administrator
Division of Air Quality
Department of Environmental Quality
122 W. 25th Street
Cheyenne, WY 82002

RE: Comments on Wyoming's Proposal to Approve Construction of a Coal-Fired Power Plant ("Dry Fork Station") by Basin Electric Power Cooperative

Dear Mr. Finley,

The Wyoming Chapter of the Sierra Club, Wyoming Outdoor Council, Wyoming Wilderness Association, Powder River Basin Resource Council, Western Resource Advocates and the Natural Resources Defense Council respectfully submit the following comments on the Wyoming Department of Environmental Quality's (WYDEQ's) proposal to approve construction of a 422 megawatt (gross) coal-fired power plant to be known as the "Dry Fork Station" by Basin Electric Power Cooperative. WYDEQ's proposed approval to construct would be issued under Chapter 6 of the Wyoming Air Quality Standards and Regulations (WAQSR) including the prevention of significant deterioration (PSD) requirements of Chapter 6, Section 4 of the WAQSR because this power plant would be a "major emitting facility."

In June 2004, Wyoming joined other Western states in launching the Western Governors' Association's *Clean and Diversified Energy Initiative*. The initiative's goal is to develop 30,000 megawatts of additional clean energy in the West by 2015 and increase efficiency of energy use by 20 percent by 2020. In addition, Wyoming has committed to bringing in new "clean coal" technologies such as Integrated Gasification Combined Cycle (IGCC) power plants to help curb emissions of carbon dioxide to the atmosphere. Yet, the proposed Dry Fork coal fired power project does nothing to fulfill either of these objectives for Wyoming or the West. The Dry Fork coal project proposes utilizing hundred-year-old, pulverized coal (PC) technology that is obsolete even before the plant is built, when Westerners are calling for renewable energy and energy efficiency-and at the very least clean coal technologies-to meet our goals. How will Wyoming meet these goals and encourage new and innovative power production when we continue to permit out-dated technology?

1. WYDEQ FAILED TO MEET PUBLIC NOTICE REQUIREMENTS

Section 165(a)(2) of the Clean Air Act requires that, in order for a PSD permit to be issued, "the proposed permit has been subject to a review in accordance with [section 165 of the Clean Air Act]. . .and a public hearing has been held with opportunity for interested persons. . .including representatives of the Administrator to appear and submit written or oral presentations on the air quality impact of such source, alternatives thereto, control technology requirements, and other appropriate considerations." In EPA's implementing regulations for PSD SIPs, it is stated that the public notice for a proposed permit must provide "the degree of increment consumption that is expected from the source." 40 C.F.R. §51.166(q)(2)(iii). Wyoming has a similar provision in Section 2(m) of Chapter 6 of the WAQSR. The EPA's Environmental Appeals Board (EAB) has interpreted these provisions as meaning that the public notice for a PSD permit must include the degree of increment consumption that is expected in all of the locations impacted by the proposed source. IN THE MATTER OF HADSON POWER 14- BUENA VISTA, PSD Appeal Nos. 92-3, 92-4, 92-5, 4 E.A.D. 258, 272-3 (EAB 1992). In particular the EAB noted "We do not believe that the phrase 'degree of increment consumption' can be read as allowing for providing data at only one location, albeit the one with the greatest projected consumption. Different potential commentors may have an interest in different areas to be impacted and would want, and would reasonably be entitled to, available data on increment consumption at the area of their particular concern. Otherwise their ability to comment on the air quality impact and proposed alternatives would be severely limited " *Id.* at 272.

WYDEQ's public notice for the Dry Fork facility only identified the degree of sulfur dioxide (SO_2) increment consumption "near the plant site." WYDEQ did not identify the degree of increment consumption for NO_2 or PM_{10}. Further, WYDEQ did not identify the degree of increment consumption expected in any Class I areas. This omission seems particularly egregious for the Northern Cheyenne Indian Reservation Class I area, especially considering that Basin Electric's cumulative SO_2 increment analysis shows that there would be SO_2 increment violations in that area and that Dry Fork would contribute to SO_2 increment concentrations in that area. Therefore, WYDEQ failed to meet public notice requirements for the Dry Fork proposed permit.

The imperative to provide public notice of increment consumption at specific Class I areas flows directly from the core statutory purposes of the PSD program. Section 160(2) of the Clean Air Act plainly provides that a central statutory purpose of the PSD program is "to preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monuments, national seashores, and other areas of special national, scenic, or historic value." Congress also instructed that the PSD program is intended "to assure that any decision to permit increased air pollution in any area to which this section applies is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decisionmaking process." CAA Sec. 160(5). Adequate notice is a necessary predicate to informed public participation in the PSD permit process.

Thus, WYDEQ failed to adequately inform the public of the degree of increment consumption expected by Dry Fork in all areas to be impacted by the proposed facility and, accordingly, WYDEQ must re-issue its public notice to comply with public participation requirements.

2. THE PROPOSED DRY FORK PERMIT AND BASIN ELECTRIC'S PERMIT APPLICATION FAIL TO ADDRESS CARBON DIOXIDE AND OTHER GREENHOUSE GAS EMISSIONS

Basin Electric's permit application for Dry Fork did not address carbon dioxide (CO_2) or other greenhouse gases to be emitted from plant. WYDEQ's proposed permit also did not address greenhouse gas emissions. However, such emissions can be very significant from coal-fired boilers. Based on information in the permit application and AP-42 emission factors, Dry Fork has a potential to emit 4.857 million tons of carbon dioxide each year.[1]

We believe that the EPA, and the State of Wyoming have a legal obligation to regulate CO_2 and other greenhouse gases as pollutants under the Clean Air Act. Twelve states, 14 environmental groups and two cities have filed suit against EPA, asserting that EPA has ample authority under the Clean Air Act to regulate air pollutants associated with climate change and that EPA must adhere to the enumerated statutory factors in determining whether global warming pollution is reasonably anticipated to endanger public health and welfare. This issue is now before the U.S. Supreme Court.[2] In addition, legislation to address global warming and CO_2 emission is being considered by Congress, and many states (including California) are increasingly attempting to regulate CO_2 emissions.

At the minimum, WYDEQ should have required consideration of emissions of CO_2 in the Dry Fork best available control technology (BACT) analysis. However, neither Basin Electric or WYDEQ considered CO_2 or other greenhouse gases in the BACT analysis and thus the proposed Dry Fork permit is seriously deficient in this regard.

The EPA has long recognized the obligation for a permitting authority to meaningfully consider collateral environmental impacts, even if such impacts are due to unregulated pollutants. *See In re North County*, 2 E.A.D. 229, 230 (Adm'r 1986). The Administrator stated in that case:

> Region IX's [asserts] that EPA lacks the authority to "consider" pollutants not regulated by the [CAA] when making a PSD determination. This assertion is correct only if it is read narrowly to mean EPA lacks the authority to impose limitations or other restrictions directly on the emission of unregulated pollutants. EPA clearly has no such authority over emissions of unregulated pollutants. Region IX's assertion is overly broad, however, if it is meant as a limitation on EPA's authority to evaluate, for example, the environmental impact of unregulated pollutants in the course of making a BACT determination for the regulated pollutants. EPA's authority in that respect is clear. . . . Hence, if application of a

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[1] Emissions of CO_2 were calculated based on AP-42 emission factors for subbituminous coal combustion in Table 1.1-20 of Chapter 1 of AP-42 and from the expected annual tonnage of coal to be utilized at Dry Fork provided in Appendix B of the November 10, 2005 Dry Fork permit application).

[2] Commonwealth of Massachusetts, et al. v. EPA, U.S. Supreme Court Docket No. 05-1120 (cert. granted June 26, 2006). See Brief for the Petitioners, filed Aug. 31, 2006.

control system results directly in the release (or removal) of pollutants that are not currently regulated under the Act, the net environmental impact of such emissions is eligible for consideration in making the BACT determination. The analysis may take the form of comparing the incremental environmental impact of alternative emission control systems with the control system proposed as BACT; however, as in any BACT determination, the exact form of the analysis and the level of detail required will depend upon the facts of the individual case. Depending upon what weight is assigned to the environmental impact of a particular control system, the control system proposed as BACT may have to be modified or be rejected in favor of another system. In other words, *EPA may ultimately choose more stringent emission limitations for a regulated pollutant than it would otherwise have chosen if setting such limitations would have the incidental benefit of restricting a hazardous but, as yet, unregulated pollutant.*[3]

Thus, even if WYDEQ were to conclude (erroneously in our view) that CO_2 should not be a regulated "pollutant" under the federal CAA or state clean air laws, it still must assess any differences in the potential global warming impacts of competing BACT technologies as part of the mandatory collateral impacts analysis. By its very nature the collateral impacts analysis is intended to target pollutants that are otherwise unregulated under the PSD provisions – and the statute is clear on its face that this inquiry is not limited exclusively to "pollutants" that the CAA otherwise regulates, but encompasses environmental impacts more broadly. See CAA § 169(3).

The scientific consensus around global warming, and the significance of anthropogenic sources, has reached a point of unanimity; that is to say, global warming is real, and people are contributing to this phenomenon in a significant way.[4] Moreover, the likely impacts of global warming are profound. As a result, the sense of urgency related to addressing global warming – by reducing greenhouse gas emissions – has increased dramatically.[5] The reports prepared by the Intergovernmental Panel on Climate Change (IPCC) provide scientific support for these concerns stated in the strongest possible terms.[6]

EPA itself recognizes that global warming is likely to have numerous and particularly severe adverse public health and environmental consequences, including direct heat-related effects, extreme weather events, climate-sensitive disease impacts, air quality effects, agricultural effects (and related impacts on nutrition), wildlife and habitat impacts, biodiversity impacts, impacts on marine life, economic effects, and social disruption (such as population displacement).[7] Indeed,

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[3] The EAB has consistently upheld his proposition. *See*, e.g., *In re Genesee Power Station*, 4 E.A.D. 832 (EAB 1993); *In re Steel Dynamics*, 9 E.A.D. 165 (EAB 2000).

[4] The International Panel on Climate Change (IPCC) recently issued its Fourth Assessment on Global Warming, essentially eliminating any doubt about the existence of global warming and the contribution of human activities. See *Fossil Fuels are to Blame, World Scientists Conclude,* USA Today, Jan. 31, 2007; http://www.ipcc.ch/SPM2feb07.pdf.

[5] Global emissions of carbon amount to more than seven billion tons each year, and in order to address the impending effects of serious climate destabilization we must take action now to reduce these emissions. The more carbon we add to the atmosphere, the more dramatic the rise in temperature will be, and the more severe the climate-related environmental impacts, social costs, human health effects, and impacts on habitat, species, ecosystems, and biodiversity. *See* SCIENTIFIC AMERICAN, What To Do About Coal (Sept. 2006) available at: http://www.sciam.com/article.cfm?chanID=sa006&articleID=0003F275-08F2-14E6-BFF883414B7F0000.

[6] IPCC reports are available at http://www.ipcc.ch/.

[7] *See* http://www.epa.gov/climatechange/effects/health.html.

numerous studies directly link global warming with increases in a variety of serious environmental, health, economic, and ecological impacts.[8]

In the BACT context, there is also no reason to dismiss important considerations of CO_2 emissions simply because numerous sources collectively contribute to global warming. Indeed, many of the foundational regulatory provisions of the CAA, such as the National Ambient Air Quality Standard (NAAQS), are predicated on the principle of reducing relatively small quantities of emissions from large numbers of sources in order to reduce harmful levels of pollutants in the ambient air.[9] The potential health, environmental, energy, and welfare consequences of global warming are profound. Reducing CO_2 emissions, especially those associated with coal-fired power plants, is the single most important strategy to fight these effects.[10] Because coal-fired power plants are the single largest source of CO_2 emissions, they are a critical part of any efforts to address the effects of global warming.

In short, the consideration of the consequence of CO_2 emissions as a collateral environmental impact in the BACT analysis is completely independent of CO_2's status as a pollutant under the Clean Air Act or Wyoming law, and considering CO_2 emissions when a *new* coal plant is

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[8] The Los Angeles Times recently reported on a new study that shows that global warming is likely to cause extreme events that will damage ecosystems, harm public health, and disrupt society well before the end of the century. *See* http://www.latimes.com/news/nationworld/nation/la-na-climate20oct20,0,4849957.story?coll=la-home-nation. *See, also* links to the following studies at http://www.pewclimate.org/global-warming-in-depth/environmental_impacts/reports/ : Observed Impacts of Climate Change in the U.S., Coping With Global Climate Change: The Role of Adaptation in the United States, A Synthesis of Potential Climate Change Impacts on the United States, Coral Reefs & Global Climate Change: Potential Contributions of Climate Change to Stresses on Coral Reef Ecosystems, Forests & Global Climate Change: Potential Impacts on U.S. Forest Resources, Coastal and Marine Ecosystems and Global Climate Change: Potential Effects on U.S. Resources, Aquatic Ecosystems and Global Climate Change: Potential Impacts on Inland Freshwater and Coastal Wetland Ecosystems in the United States, Human Health & Global Climate Change: A Review of Potential Impacts in the United States, Ecosystems & Global Climate Change: A Review of Potential Impacts on U.S. Terrestrial Ecosystems and Biodiversity, Sea-Level Rise & Global Climate Change: A Review of Impacts to U.S. Coasts, Water and Global Climate Change: Potential Impacts on U.S. Water Resources, The Science of Climate Change: Global and U.S. Perspectives, Agriculture & Global Climate Change: A Review of Impacts to U.S. Agricultural Resources. STERN REVIEW ON THE ECONOMICS OF CLIMATE CHANGE, available at: http://www.hm-treasury.gov.uk/Independent_Reviews/stern_review_economics_climate_change/sternreview_index.cfm. These studies are incorporated here by reference.

[9] CAA § 112 similarly seeks to bring levels of hazardous air pollutants down to safe levels by regulating multiple source and multiple source categories of certain pollutants. There are other examples as well (e.g., SO_2 reductions under the acid rain program, and the regulations of emission from mobile sources). As a former EPA Assistant General Counsel puts it, ignoring CO_2 in the collateral impacts analysis because of the collective contribution of numerous sources would be:

> a recipe for total inaction that has been rejected in considering other air pollution problems and should be as to CO_2 as well. Rather, sizable sources such as coal-fired power plants must be viewed in terms of their contribution to the cumulative problem of climate change and the need—at least in the absence of a comprehensive regulatory program of CO_2 control—to mitigate that contribution.

Foote, 34 ELR at 10665. See also Foote, 34 ELR 10663-665 (discussing among other things why consideration of CO_2 in this context would not have unintended negative environmental effects). (This paper is included as Attachment 2 to this letter).

[10] *See, e.g.*, SCIENTIFIC AMERICAN, What To Do About Coal (Sept. 2006), available at: http://www.sciam.com/article.cfm?chanID=sa006&articleID=0003F275-08F2-14E6-BFF883414B7F0000.

proposed (i.e. as a part of the process of pre-construction review), is *by far* the most cost-effective stage to evaluate the possibility of achieving reductions.[11]

Given the potential for extremely severe environmental and public health related impacts from global warming; given that the phenomenon of global warming is undeniably connected to anthropogenic releases of CO_2; given that electric power production is the single most significant source of CO_2 emissions in the U.S. and the world; and given that coal fired power plants (such as the one proposed by Basin Electric) contribute the vast majority of energy-sector CO_2 emissions; it is simply untenable that the effects of global warming would be inherently outside the scope of the "collateral impacts" that permit applicants and permitting authorities must consider in connection with the issuance of PSD permits. Thus, any assertion that CO_2 emissions (and global warming) are somehow beyond the broad mandate to consider "environmental impacts" under the PSD program must be rejected.

At a minimum, therefore, WYDEQ must consider emissions of CO_2 in its BACT analysis for the Dry Fork facility. In fact, the EPA's October 1990 New Source Review (NSR) Workshop Manual specifically states that "[s]ignificant differences in noise levels, radiant heat, or dissipated static electrical energy, or greenhouse gas emissions may be considered" in assessing environmental impacts from a proposed coal plant. See, EPA NSR Workshop Manual, p. b.49. (Attachment 1). Further, a recently issued paper entitled *Considering Alternatives: The Case for Limiting CO_2 Emissions from New Power Plants through New Source Review* by Gregory B. Foote (Attachment 2) discusses the regulatory background to support consideration of CO_2 impacts when permitting a new source and, in particular, a new coal-fired power plant. This paper indicates that it is entirely appropriate to consider CO_2 emissions when evaluating environmental impacts under the new source review permit program, and the paper also suggested approaches for evaluating technologies in terms of CO_2 emissions.

As discussed further below, there are technologies available that produce electricity from coal more efficiently (burning less coal and thus emitting less CO_2 to produce the same amount of electricity) as well as technologies that more readily accommodate carbon sequestration. The Dry Fork permit must not be issued by WYDEQ without such thorough and unbiased evaluation of these other technologies.

Permitting authorities' obligation to consider collateral environmental impacts extends not only to emission of CO_2, but also to other potential environmental impacts, such as the consequences of water use, impacts from the generation of hazardous wastes, and impacts on species and habitat. These obligations grow directly from the definition of BACT at CAA § 169(3).

The permitting authority, here WYDEQ, must consider the full range of potential collateral environmental impacts. This includes consideration of impacts related to water use and generation and disposal of solid waste products. One of the benefits of IGCC compared with antiquated conventional coal technology is dramatically lower water requirements – which may have a variety of environmental benefits (related to both water intake requirements and wastewater discharges). Additionally, IGCC generates considerable less solid waste than

[11] For example, industry would consider it cost prohibitive to consider retrofits for a pulverized coal plant in order to seriously address CO_2 emissions (by installing CO2 capture and control equipment for example).

conventional PC plants, and that waste is in a form that is much more stable and less likely to leach into the environment.[12] The applicant (and the permitting authority) must consider these factors, as well as the benefits discussed above regarding CO_2 benefits, in the context of an evaluation of collateral environmental impacts. These impacts are important to protecting public health, protecting water resources, and protecting the natural environment.

With respect to endangered species, the EAB explained in *In re Indeck-Elwood*:

> [W]e find [that the] CAA provides that, in establishing BACT limits, the permit issuer is to "tak[e] into account energy, *environmental*, and economic *impacts* and other costs." CAA § 169(3), 42 U.S.C. § 7479(3) (emphasis added). We think "environmental impacts" is most naturally read to include ESA-identified impacts to endangered or threatened species. . . . We therefore conclude that the CAA's PSD requirements and the ESA requirements are appropriately viewed as complementary in nature, such that impacts on ESA-identified threatened and/or endangered species can be taken into account when considering a PSD permit application and establishing a permit's terms and conditions.[13]

Whether or not a permitting authority is subject to the Endangered Species Act for a particular project, impacts on species and habitat are, undeniably, "environmental impacts" – and therefore must be considered in connection with an applicant's collateral impacts analysis. Moreover, this obligation exists above and beyond a permitting authority's affirmative obligation to assess impacts on soils and vegetation.

The U.S. Fish and Wildlife Service lists 56 threatened or endangered plant and animal species in the mountain prairie region (including Wyoming), and another 11 candidates for listing. *See* http://mountain-prairie.fws.gov/wy.html. Clearly, therefore, an analysis of potential impacts on species and habitat is an important part of the information to which the public is entitled during the public comment period (especially where there are competing technologies – as discussed herein – that may have significantly different environmental impacts).

Indeed, where competing BACT technologies would have significantly different collateral environmental impacts – that would have distinct affects on soils, vegetation, and/or threatened or endangered species – the EAB has made clear that this analysis is especially important to the appropriate implementation of the Clean Air Act and the meaningful participation of the public in the PSD permitting process.[14] Moreover, the permitting authority is obligated (based on the definition of BACT in section 169) to specifically evaluate the differences in collateral

[12] *See* U.S. EPA, *Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies*, at p. 3-34, available at: http://www.epa.gov/air/caaac/coaltech/2007_01_epaigcc.pdf.
[13] *In re Indeck-Elwood*, PSD Appeal 03-04, at 108-109, 13 E.A.D. __ (Sept. 27, 2006).
[14] The collateral impacts analysis for soils and vegetation is important for each facet of the Dry Fork Station permit, including ambient air quality assessment; technology assessments and selection (for both primary and secondary emission units); and other collateral environmental effects (such as water, solid waste, and non-PSD air pollutants) – especially when the relative benefits of other technologies (like IGCC) are considered.

environmental impacts between competing technologies.[15] Because WYDEQ did not meaningfully evaluate IGCC, it has failed to meet it statutory obligation, and the public has been denied its right to comment on a vital component of the statutory decision-making process.

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3. WYDEQ/BASIN ELECTRIC MUST CONSIDER THE COLLATERAL COSTS OF FUTURE CO_2 REGULATION IN THE BACT ANALYSIS

BACT also requires consideration of costs that are relevant to the selections of one BACT option over another. In this context, costs associated with the future regulation of carbon dioxide emissions from power plants should be considered in deciding between BACT options for the Dry Fork facility, and BACT options that are less intense emitters of CO_2 should be given preference.

The regulation of CO_2 emissions in the U.S. in the very near future is virtually certain. The international community has already begun to take action to curb such emissions – 190 countries have joined the United Nation's Framework Convention on Climate Change, and most have ratified the Kyoto Protocol (the U.S. and Australia alone among the industrialized countries have not). More recently, certain States have also taken concrete steps to reduce their carbon footprint; for example, several northeast states have formed the Region Greenhouse Gas Initiative (RGGI) to reduce carbon emission in that part of the country.[16] The state of California also has passed legislation to limit the state's greenhouse gas emissions, and to require that new long-term investments in baseload generation meet a minimum standard for greenhouse gas emissions. Also, several western and midwest states are now contemplating action to limit greenhouse gases. Moreover, members of Congress have introduced numerous bills, amendments, and resolutions specifically addressing global warming in 2005, and the Senate passed a resolution calling for a "comprehensive and effective national program of mandatory, market-based limits and incentives on emissions of greenhouse gases that slow, stop, and reverse the growth of such emissions." [17,18] Studies continue to show that such regulation is the only responsible and economically sensible course of action; for example, the Stern Report[19] concluded that while the cost of inaction could range from 5 percent to 20 percent of global GDP, the cost of stabilizing ambient concentrations at 450 to 550 ppm CO_2-equivalent can be accomplished for about 1 percent of GDP. According to the report, the key policies required to meet this goal are the implementation of carbon emission regulations (such as cap and trade measures), the deployment of low-carbon-technologies and further low-carbon innovation, and the removal of barriers to energy efficiency.

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[15] In this context, relevant difference may include difference in the quantity or nature of air emissions, such as NOx, SO2, CO, PM, and mercury, as well as impacts related to other factors such as water usage, solid waste handling and disposal, waste water or process water discharges, etc.

[16] See www.rggi.org.

[17] Senate Amendment 866 a Sense of the Senate climate change resolution proposed by Senators Bingaman, Specter, Domenici, Alexander, Cantwell, Lieberman, Lautenberg, McCain, Jeffords, Kerry, Snowe, Collins and Boxer adopted by a vote of 53 to 44 on June 22, 2005. Congressional Record, Vol. 151, June 22 2005, S7033 – S7037, S7089.

[18] See www.aip.org/fyi/2005/114.html. In May of this year the House Appropriations Committee approved similar language. See www.pewclimate.org/what_s_being_done/in_the_congress/index.cfm for more information on Congressional action on global warming.

[19] STERN REVIEW ON THE ECONOMICS OF CLIMATE CHANGE, available at: http://www.hm-treasury.gov.uk/Independent_Reviews/stern_review_economics_climate_change/sternreview_index.cfm..

The general consensus in the U.S. is that federal CO_2 emission controls are inevitable. Notably, the utility industry as well has begun to recognize that national carbon emission limits are both necessary and desirable; for example, executives from Duke Energy and NRG have recently made statements strongly supporting the idea of national carbon limits, and emphasizing the responsibility of the electric power sector to take action to address global warming.[20] Tellingly, a diverse group of entities (including utilities, environmental groups, petroleum and chemical companies and others – including BP, Duke Energy, DuPont, and the Natural Resources Defense Council) recently formed the U.S. Climate Action Partnership ("USCAP"), calling for "the prompt enactment of national legislation in the United States to slow, stop and reverse the growth of greenhouse gas (GHG) emissions over the shortest period of time reasonably achievable." Because power generation is the single most significant source of CO_2 in the United States (accounting for nearly 40 percent of U.S. emission), this industry – and coal-fired power generation in particular – is certain to be among the first industry sectors affected by carbon-related regulation.

As the momentum to regulate greenhouse gas emissions continues to grow around the country and internationally, businesses are increasingly recognizing the monetary risk associated with impending carbon emissions controls. For example:

- PacifiCorp and Idaho Power Company have explicitly addressed the financial risk associated with carbon emissions in their recent IRPs. Idaho Power's draft IRP, for example, explains that the utility analyzed the financial risk of carbon emissions because "it is likely that carbon dioxide emissions will be regulated within the thirty year timeframe addressed in the 2004 IRP."[21]
- PG&E's long-term plan recognizes the risk of increasing costs for carbon emissions.
- Last year, the Coalition for Environmentally Responsible Economies (CERES) convened a Dialogue among experts from the power sector, environmental groups, and the investment community focusing on climate change. The Dialogue participants found that greenhouse gas emissions will be regulated in the U.S., and that the "issue is not whether the U.S. government will regulate these emissions, but when and how."[22]
- Utility shareholders are recognizing that the likelihood of regulation of carbon emissions represents a real financial risk, and are asking utilities to disclose those risks. Thirteen major public pension funds, which manage $800 billion in assets, recently asked the Securities and Exchange Commission to require companies to disclose the financial risks they face from climate change.[23] Meanwhile, in 2004 alone institutional shareholder groups filed 29 proposals asking individual companies to outline their response to global warming.

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[20] *See, e.g.*, http://www.cleartheair.org/proactive/newsroom/release.vtml?id=25835.
[21] See PacifiCorp, "2003 Integrated Resource Plan," www.pacificorp.com. Idaho Power Company, "Draft 2004 Integrated Resource Plan," www.idahopower.com/energycenter/2004irpdraft.htm.
[22] Coalition for Environmentally Responsible Economies, "Electric Power, Investors, and Climate Change," June 2003, p. 4 (www.ceres.org/reports/main.htm).
[23] Margaret Kriz, "Measuring The Climate For Change," Congress Daily, April 22 2004.

There is overwhelming evidence that carbon emissions will be regulated in the very near future, and accordingly, businesses in the U.S. are taking this financial risk quite seriously.[24]

In short, the costs associated with the imminent regulation of CO_2 (certainly within the lifetime of the proposed Dry Fork facility) should be expressly considered in connection with the selection of BACT. Because Basin Electric proposes to use a carbon-intensive PC technology, and because other BACT options have significantly better CO_2 emissions performance (in particular IGCC, as discussed below – especially when used in conjunction with carbon capture and disposal),[25] the cost of future CO_2 regulation is directly relevant to the BACT analysis in this case. Thus, WYDEQ must require this cost to be considered in the BACT analysis for the Dry Fork facility.[26]

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4. FEDERAL AND STATE CLEAN AIR LAWS REQUIRE BASIN ELECTRIC TO CONSIDER THE APPLICATION OF PRODUCTION PROCESSES AND AVAILABLE METHODS, SYSTEMS AND TECHNIQUES TO LOWER AIRBORNE CONTAMINANTS

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[24] Moreover, emission allowances that effectively "grandfather" the CO_2 emissions of existing power plants (particularly those plants being permitted now – when the writing is already on the wall) is highly unlikely and would be entirely inappropriate. Rather, it is probable that the Congress will adopt legislation in the near term that is consistent with the 2005 U.S. Senate resolution calling for a "comprehensive and effective national program of mandatory, market-based limits and incentives on emissions of greenhouse gases that slow, stop, and reverse the growth of such emissions." Given the number of plants being proposed and the fact that the Senate is on record calling for a program to reduce emissions, the law is likely to limit emission allowances to coal plants that were fully permitted or actually in operation prior to the Senate resolution (at the latest).

[25] IGCC inherently emits less CO_2 than pulverized coal technologies because of its greater efficiency, but it also provides the ability to capture and dispose of CO_2 in order to reduce CO_2 emission by perhaps 80-90 percent.

[26] There are various cost estimates related to future carbon dioxide emissions control that span a range from about $8 per ton to more than $40 per ton. For example, there is currently a carbon dioxide trading program in Europe that serves as one component of European efforts to address global warming. In that trading program, carbon dioxide emissions have reached a high of about $42 per ton. *See* http://pubs.acs.org/subscribe/journals/esthag-w/2006/jul/business/mb_carbonprices.html. Several states in the U.S. have specifically required consideration of future carbon costs as a part of their energy planning processes. In particular, the California Public Utilities Commission requires that the utilities use a "greenhouse gas adder" of $8 per ton CO_2, beginning in 2004 and escalated at 5 percent per year, in long-term planning and procurement for purposes of evaluating new long-term resource investments. See California Public Utilities Commission, Decision No. 04-12-048, and Decision 05-04-024. The Montana Public Service Commission has a similar requirement. See Montana Public Service Commission, "Written Comments Identifying Concerns Regarding Northwestern Energy's Compliance with A.R.M. 38.5.8201-8229," Docket No. N2004.1.15, *In the Matter of the Submission of Northwestern Energy's Default Electricity Supply Resource Procurement Plan* (August 17, 2004). Idaho Power is using a carbon cost of $14/ton starting in 2012. See http://www.idahopower.com/energycenter/irp/2006/2006IRPFinal.htm. In a recent filing before the Florida Public Services Commission, Florida Power and Light estimated CO_2 emission costs ranging up to more than $100 per ton during the life of their proposed coal plant. See . http://www.psc.state.fl.us/library/filings/07/01093-07/01093-07.pdf. As a result, reasonable estimates for the average annual cost of CO_2 under expected U.S. regulations range from about $8 to well above $40 per ton. This range of costs is supported by a recent study by Synapse Energy Economics, Inc. available at: http://www.synapse-energy.com/Downloads/SynapsePaper.2006-06.Climate-Change-and-Power.pdf.Even assuming a relatively low carbon cost, of say $12 per ton, it is clear that emission from a facility like Dry Fork could create a significant financial burden.

Section 165(a)(4) of the Clean Air Act (CAA) provides that "no major emitting facility on which construction is commenced after August 7, 1977, may be constructed in any area to which this part applies unless...the facility is subject to the best available control technology for each pollutant subject to regulation under this chapter emitted from, or which results from, such facility."[27] The requirement for conducting a BACT analysis and setting an emission limit reflective of BACT is codified in Chapter 6, Section 4 (b)(ii) of the Wyoming Air Quality Standards and Regulations.

BACT requires a comprehensive analysis of all potentially available emission control measures, expressly including input changes (such as use of clean fuels), process and operational changes, and the use of add-on control technology. Additionally, it requires that a new source comply with emission limits that correspond to the *most effective* control measures available, unless the source can affirmatively demonstrate that use of the most effective control measures would be technologically or economically infeasible.

BACT is specifically defined under Wyoming law as follows:

> an emission limitation (including a visible emission standard) <u>based on the maximum degree of reduction</u> of each pollutant subject to regulation under these Standards and Regulations or regulation under the Federal Clean Air Act, which would be emitted from or which results for any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines <u>is achievable for such source or modification through application or production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.</u>

Chapter 6, Section 4(i) of the WAQSR. [Emphasis added.]

Wyoming's definition essentially mirrors the federal definition of BACT in 40 C.F.R. §52.21(b)(12).

EPA has repeatedly acknowledged that the PSD program is technology forcing and intended to become more stringent over time as control technologies improve and new cleaner processes are introduced. For example, the EAB has explained that:

> A major goal of the CAA was to create a program that was technology forcing. . . . "The Clean Air Amendments were enacted to 'speed up, expand, and intensify the war against air pollution in the United States with a view to assuring that the air we breathe throughout the Nation is wholesome once again.'" . . . .
> In keeping with this objective, the program Congress established was particularly aggressive in its pursuit of state-of-the-art technology at newly constructed sources. At these sources, pollution control methods could be

[27] 42 U.S.C. §7475(a)(4).

> efficiently and cost-effectively engineered into plants at the time of construction.[28]

Similarly, the EPA Administrator has explained that the BACT provisions of the PSD program are principally technology-forcing and are intended to foster "rapid adoption" of improvements in emissions control technology.[29]

The definition of BACT includes coal gasification. The legislative history of the amendment adding the term "innovative fuel combustion techniques" to the Clean Air Act's definition of "BACT" is clear. Coal gasification must be considered. The relevant passage of the debate is excerpted below:

> Mr. HUDDLESTON. Mr. President, the proposed provisions for application of best available control technology to all new major emission sources, although having the admirable intent of achieving consistently clean air through the required use of best controls, if not properly interpreted may deter the use of some of the most effective pollution controls. The definition in the committee bill of best available control technology indicates a consideration for various control strategies by including the phrase "through application of production processes and available methods systems, and techniques, including fuel cleaning or treatment." And I believe it is likely that the concept of BACT is intended to include such technologies as low Btu gasification and fluidized bed combustion. But, this intention is not explicitly spelled out, and I am concerned that without clarification, the possibility of misinterpretation would remain. It is the purpose of this amendment to leave no doubt that in determining best available control technology, all actions taken by the fuel user are to be taken into account--be they the purchasing or production of fuels which may have been cleaned or up-graded through chemical treatment, gasification, or liquefaction; use of combustion systems such as fluidized bed combustion which specifically reduce emissions and/or the post-combustion treatment of emissions with cleanup equipment like stack scrubbers. The purpose, as I say, is just to be more explicit, to make sure there is no chance of misinterpretation. Mr. President, I believe again that this amendment has been checked by the managers of the bill and that they are inclined to support it.
>
> Mr. MUSKIE. Mr. President, I have also discussed this amendment with the distinguished Senator from Kentucky. I think it has been worked out in a form I can accept. I am happy to do so. I am willing to yield back the remainder of my time.[30]

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[28] *In Re Tenn. Valley Authority*, 9 E.A.D. 357, 391 (EAB 2000) (citing *WEPCO*, 893 F.2d at 909 and H.R. Rep. No. 95-294, at 185, *reprinted in* 1977 U.S.C.C.A.N. at 1264).

[29] *In re Columbia Gulf Transmission* Co., 2 E.A.D. 824, 828-29 (Adm'r 1989). *See also In re Kawaihae Cogeneration Project*, 7 E.A.D. 107, 127 n.26 (EAB 1997); *In re Metcalf Energy Center*, PSD Appeal 01-7, 01-8, at 15 (Aug. 10, 2001).

[30] 95th Congress, 1st Session (Part 1 of 2) June 10, 1977 Clean Air Act Amendments of 1977 A&P 123 Cong. Record S9421.

Clearly, both the language of the Act itself and the unequivocal expressions of Congressional intent in the legislative history indicate, that in order to fully comply with the Act, the emission limits identified as BACT must incorporate consideration of more than just add-on emission control technology – they must also reflect appropriate considerations of fuel quality (such as low sulfur coal) and process changes (including specifically innovative combustion techniques such as coal gasification). Indeed, this requirement is not only consistent with, but necessary to the very core objective of PSD permitting – to bring about the rapid adoption of cleaner technologies that provide for a greater reduction in regulated emissions.[31] In "notably capacious terms," *Alaska v. EPA,* 540 U.S. 461 (2004), the statute provides that BACT includes "application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques." CAA Sec. 169(3).

EPA and federal courts have consistently interpreted the BACT provisions found in the Clean Air Act and the EPA's regulations as embodying certain core criteria that require the permit applicant either to implement the most effective available means for minimizing air pollution or justify its selection of less effective means on grounds consistent with the purposes of the Clean Air Act. Indeed, the discretion of the permitting agency in determining BACT is deliberately confined by the statute's use of the "strong, normative terms 'maximum' and 'achievable.'" *Alaska v. EPA,* 540 U.S. 461 (2004).

In *Citizens for Clean Air v. EPA,*[32] the Ninth Circuit held that "initially the burden rests with the PSD applicant to identify the best available control." As stated in long-standing EPA guidance, "[r]egardless of the specific methodology used for determining BACT, be it 'top-down,' 'bottom-up,' or otherwise, the same core criteria apply to any BACT analysis: the applicant must consider all available alternatives, and [either select the most stringent of them or] demonstrate why the most stringent should not be adopted."[33] Accordingly, the PSD permit applicant not only must identify all available technologies, including the most stringent, but it must also provide adequate justification for dismissing any available technologies.

Consistent with these core criteria, the EPA's NSR Workshop Manual establishes that, as the first step in the "top-down" BACT analysis, the applicant *must* consider all "available" control options:

> The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit,

[31] Emission controls under the Clean Air Act are universally recognized as including process changes (including inherently cleaner processes) as well as add-on control technology. The PSD provisions expressly recognize this in the definition of BACT included in section 169 of the Act. Other sections of the Act reinforce the fact that Congress generally understood and accepted that emission control is often most effectively achieved through process changes. *See* CAA § 112(d)(2) (identifying mechanisms for reducing emission of hazardous air pollutants as including, in addition to add-on controls, "process changes, substitutions of materials or other modifications," as well as "design, equipment, work practice, or operational standards").

[32] 959 F.2d 839, 845 (9th Cir. 1992)

[33] Memorandum from John Calcagni, Director of EPA Air Quality Management Division, to EPA Regional Air Directors (June 13, 1989), at 4 (emphasis added).

> process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant. This includes technologies employed outside of the United States. As discussed later, in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.[34]

EPA further explains that potential control options can be categorized in three ways:

- Inherently lower emitting processes/techniques
- Add-on controls
- Combinations of inherently lower emitting processes/techniques and add-on controls.[35]

With respect to inherently lower emitting processes, EPA explains that "[l]ower-polluting processes should be considered based on demonstrations made on the basis of manufacturing identical or similar products from identical or similar raw materials or fuels."[36]

"The term 'available' is used…to refer to whether the technology 'can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term.'"[37] In keeping with the stringent nature of the BACT requirement, EPA has repeatedly emphasized that "available"

> is used in the broadest sense under the first step and refers to control options with a "practical *potential* for application to the emissions unit" under evaluation. . . . The goal of this step is to develop a comprehensive list of control options.[38]

EPA adjudicatory decisions also examine the core requirements for the BACT determination process. "Under the top-down methodology, applicants must apply the best available control technology unless they can demonstrate that the technology is technically or economically infeasible. The top-down approach places the burden of proof on the *applicant* to justify why the proposed source is unable to apply the best technology available."[39] That is, a BACT review

[34] NSR Manual, at p. B.5 (emphasis added).
[35] *Id.* at B.10.
[36] *Id.*
[37] In re: Maui Electric Company, PSD Appeal No. 98-2 (EAB September 10, 1998), at 29-30 (quoting NSR Manual at B.17).
[38] In re: Knauf Fiber Glass, PSD Appeal Nos. 98-3 – 98-20 (EAB February 4, 1999), at 12-13 (quoting NSR Manual at B.5) (emphasis added by EAB); see also In re: Steel Dynamics, Inc., PSD Appeal Nos. 99-4 and 99-5 (EAB June 22, 2000), at 29 n.24 (citing Knauf with approval); NSR Manual at B.10 ("The objective in step 1 is to identify all control options with potential application to the source and pollutant under evaluation."); id. at B.6 (emphasizing that a proper Step 1 list is "comprehensive").
[39] In re: Spokane Regional Waste-to-Energy Applicant, PSD Appeal No. 88-12 (EPA June 9, 1989), at 9) (internal quotation marks omitted) (emphasis in original); see also In re: Inter-Power of New York, Inc. PSD Appeal Nos. 92-8 and 92-9 (EAB March 16, 1994) ("Under the 'top-down' approach, permit applicants must apply the most

must facilitate adopting the best available technology, not be used as a basis for rejecting applicable technology.

Whatever analytical process is utilized for determining BACT, these core criteria – the requirement to consider all available technologies, including the most stringent, and to provide adequate justification in the administrative record for dismissing any of the technologies based on relevant statutory factors – must be satisfied.[40]

Thus, to conduct a BACT analysis for the Dry Fork facility, WYDEQ must thoroughly evaluate all available control measures. IGCC is commercially available today and it reflects an inherently lower emitting process for producing electricity from coal. Therefore, this technology should have been thoroughly evaluated as part of the Dry Fork BACT analysis.

15 Any Arguments that IGCC Does Not Need to Be Considered Because It Would Be "Redefining the Source" are Flawed and Must Fail

In its air quality construction permit application, Basin Electric stated "EPA has not considered the BACT requirement as a means to redefine the source. . .[t]herefore, this the BACT analysis does not evaluate different combustion designs such as circulating fluidized bed or integrated gasification combined cycle since these combustion processes are fundamentally different from the chosen PC boiler design." November 10, 2005 Basin Electric Permit Application at 5-1. Basin Electric and WYDEQ have utterly ignored, in the context of evaluation of BACT for Dry Fork, process options for generating electricity from coal that could significantly reduce emissions from the facility.[41] This decision on the part of WYDEQ flies in the face of the plain language of the Clean Air Act, the clear expressions of Congressional intent, and the rulings of the EAB.

EPA has argued in other contexts that the concept of "redefining the source" may relieve it of certain obligations under the PSD program.[42] In particular, in the *Prairie State* case before the EAB, EPA argued as a matter of statutory interpretation that the Clean Air Act did not contemplate that permitting authorities would require a permit applicant to consider building a source other than the one it had proposed. In that case, the issue involved whether a proposed Illinois coal-fired power plant, that was being planned in conjunction with a new coal mine, needed to consider (as an element of its BACT analysis) using coal that was lower in sulfur than the coal that the co-located mine would produce. EPA argued (as did Illinois EPA) that

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stringent control alternative, unless the applicant can demonstrate that the alternative is not technically or economically achievable."); In the Matter of Pennsauken County, New Jersey Resource Recovery Facility, PSD Appeal No. 88-8 (EAB November 10, 1988) ("Thus, the 'top-down' approach shifts the burden of proof to the applicant to justify why the proposed source is unable to apply the best technology available.")

[40] The EAB has made clear that, regardless of the analytic process, if a control option is left out of the analysis because it is erroneously identified as not potentially available, the permit will be sent back on appeal. *See In re Three Mountain Power*, 10 E.A.D. 39, 50 (EAB 2001) (explaining that "proper BACT analysis requires consideration of all potentially 'available' control technologies").

[41] In particular, the use of IGCC would allow the facility to produce electricity from coal with dramatically lower emission of NO_x, SO_x, CO, VOC, and PM. *See, e.g.*, Permit Application for Nueces IGCC Plant (submitted to Texas Commission on Environmental Quality September 2006).

[42] *See In re Prairie State Generating Co.*, PSD Appeal 05-05, 13 E.A.D. __ (Sept. 24, 2006).

requiring the source to use coal other than that from the co-located mine would constitute an impermissible redefinition of the source.

Ultimately, in a very narrow ruling, the Board in the *Prairie State* case held that the use of coal from the co-located mine was so integral to the very purpose and intent of the project that requiring the permit applicant to consider using some other source of coal instead would defeat the purpose of the original permit application. Accordingly, the Board ruled that the Illinois EPA did not "clearly err when it determined that consideration of low-sulfur coal, because it necessarily involves a fuel source other than the co-located mine, would require Prairie State to redefine the fundamental purpose or basic design of its proposed Facility, and that, therefore, low-sulfur coal could appropriately be rejected from further BACT analysis at step 1 of the top-down review method." *Prairie State at 36-37.*

Even assuming that the Board's decision in Prairie State was consistent with the Clean Air Act, that decision clearly demonstrates that WYDEQ's failure to require consideration of innovative combustion technologies as process options for controlling emission from the Dry Fork plant is fundamentally flawed. First, the EAB's ruling recognized that the default assumption under the Clean Air Act's PSD provisions is that the use of potentially cleaner fuels (such as low-sulfur coal) will normally be a required part of the BACT analysis.[43] Only where some unique element of the facility's basic purpose made the particular BACT-related consideration *fundamentally incompatible* with the permit application, did the EAB recognize that further analysis of that BACT-related consideration might be unnecessary.[44]

In the end, even the Board's decision in Prairie State reflects an understanding that the concept of redefining the source must be subordinate to the primary objectives of the BACT analysis. That is, the specific requirements inherent in the definition of BACT will define the obligations of permit applicants and permitting authorities, unless some specific fundamental conflict exists. Moreover, while the Board concluded that the permit issuer should look "in the first instance" at "how the permit applicant, in proposing the facility, defines the goals, objectives, purposes, or basic design for the proposed facility," the permit applicant cannot manipulate the definition of the facility as a mechanism to avoid appropriate BACT analysis. *Prairie State* at 29-30. In evaluating the permit, the permit issuer must "discern which design elements are inherent to [the] purpose [of the facility], 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.* at 30.

[43] Prairie State at 22 ("Petitioners correctly observe that . . . consideration of 'clean fuels' must be a part of the BACT analysis. Specifically, . . . the Agency must consider both the cleanliness of the fuel and the use of add-on pollution control devices."). Indeed, numerous other PSD permits have identified the use of clean fuel (including low sulfur coal) as BACT for new major sources. *See, e.g. In re AES Puerto Rico* 8 E.A.D. 324 (EAB 1999); *In re Encogen Cogeneration*, 8 E.A.D. 244 (EAB 1999); *In re Hawaiian Commercial & Sugar Co.y*, PSD Appeal No. 92-1 at 5, n.7 (EAB, July 20, 1992).

[44] In *Prairie State* the Board concluded that the mine and the coal-fired power plant were proposed together as a single source under the PSD provisions, and the mine was intended to supply the entirety of the power plant's fuel throughout the plant's entire operating life. Therefore, the EAB concluded, the plant and the mine were integral parts of a single proposal and the use of coal from another source would undermine the purpose of that proposal. If the mine were capable of supplying less than the full fuel needs of the power plant over its entire life cycle, for example, the Board's analysis would likely have been different; the Board's decision suggests that in such a case the consideration of low-sulfur supplemental fuel would have been required.

Significantly, the Board specifically recognized that cost savings are not a valid purpose for a particular facility design; similarly, "the business objective of avoiding risk associated with new, innovative or transferable control technologies is not treated as a basic design element." *Prairie State* at 30 n.23. Rather, cost and risk considerations are appropriately addressed during the later steps of the top-down BACT analysis.

Basin Electric's and WYDEQ's positions on this issue are out of sync with both the Clean Air Act itself and with the EAB's treatment of the concept of "redefining the source," as well as Wyoming law. First, as discussed above, the Clean Air Act and Wyoming's PSD regulations specifically calls for consideration of "the 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 pollutant." CAA § 169(3); Chapter 6, Section 4(i) of the WAQSR. This language, on its face, requires as a part of the BACT analysis the consideration of innovative technologies like IGCC that make the generation power from coal significantly cleaner.[45]

Further, the two early decisions by the EPA Administrator that introduce the "redefining the source" policy, identify a policy that is much more limited than that put forth by Basin Electric. In *In re Pennsauken County, New Jersey, Resource Recovery Facility* the petitioner asked the EPA Administrator to deny a PSD permit to a municipal waste combustor and, instead, require the county to dispose of its waste by co-firing it with coal in existing power plants. *See* PSD Appeal No. 88-8 at 10 (Adm'r, Nov. 10, 1988). In effect, the petitioner wanted the EPA to order the applicant to engage in a different type of activity: electricity generation, rather than waste disposal. The Administrator rejected this option because the petitioner's argument was based on his objection to a waste combustor generally, not to the conditions in the permit. Thus, the Administrator held, the petitioner was asking EPA to "redefine the source" from a waste combustor to a power plant.[46] The Administrator subsequently reaffirmed the *Pennsauken County* decision and explained that "source," within the newly created "redefining the source" policy, refers to a *source category*.[47]

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[45] As discussed above, the legislative history of the Clean Air Act is equally as clear that the definition of BACT contemplates consideration of technologies like IGCC.

[46] "Petitioner Filipczak's fundamental objections to the Pennsauken permit are not with the control technology, but rather, with the municipal waste combustor itself. He urges rejection of the combustor in favor of co-firing a mixture of 20 percent refuse derived fuel and 80 percent coal at existing power plants. These objections are beyond the scope of this proceeding and therefore are not reviewable under 40 C.F.R. 124.19, which restricts review to "conditions" in the permit. Permit conditions are imposed for the purpose of ensuring that the proposed source of pollutant emissions-- here, a municipal waste combustor-- uses emission control systems that represent BACT, thereby reducing the emissions to the maximum degree possible. These control systems, as stated in the definition of BACT, may require application of "production processes and available methods, systems, and techniques, including fuel cleaning as treatment or innovative fuel combustion 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 source itself is not a condition of the permit." *Pennsauken County* at 10-11 (emphasis added).

[47] "In Pennsauken, the petitioner was urging EPA to reject the proposed source (a municipal waste combustor) in favor of using existing power plants to co-fire a mixture of 20 percent refuse derived fuel and 80 percent coal. In other words, *the petitioner was seeking to substitute power plants (having as a fundamental purpose the generation of electricity) for a municipal waste combustor (having as a fundamental purpose the disposal of municipal waste).*" *In re Hibbing Taconite Company*, 2 E.A.D. 838, 843 at n. 12 (Adm'r 1989) (parentheticals original, emphasis added).

After clarifying the "redefining the source" policy as only preventing a change in the "fundamental purpose," i.e., the source category, the Administrator further explained that the "redefining the source" policy did not allow the permitting agency to blindly accept the source design proposed by the applicant. Hibbing, 2 EAD at 842-843. In *Hibbing*, the permit applicant wanted to burn petroleum coke at its taconite plant, but EPA required the applicant to consider burning natural gas – a lower polluting process and cleaner fuel – as part of a BACT determination. *Id.* The Administrator specifically rejected the idea that requiring consideration of cleaner fuel constitutes "redefining the source" because the fundamental purpose, or source category, remains the same.[48]

In other words, *from its inception*, prior to the 1990 Manual, the "redefining the source" policy has merely stood for the concept that EPA will not require an applicant to abandon its intended purpose for some other industrial venture. To the extent EPA's subsequently-issued *draft* NSR Workshop Manual is inconsistent with prior Administrator interpretations in *Pennsauken* and *Hibbing*, which constitute the agency's official position, the draft Manual is not entitled to any deference.[49]

Because the Clean Air Act specifically calls for consideration of *production processes* and *innovative fuel combustion techniques* as means for reducing emissions from industrial sources regulated under the PSD program, even the Board's analysis in *Prairie State* would require evaluation of IGCC as part of the BACT analysis, *unless there were a specific, objectively discernable reason why doing so would be fundamentally at odds with the primary objective of the project, based on appropriate considerations not related to cost or the avoidance of risk.*[50]

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[48] [O]ne argument that could be made is that the Region, by requiring the burning of natural gas to be an alternative to be considered in the BACT analysis [for a petroleum coke-fired plant], is seeking to "redefine the source." Traditionally, EPA has not required a PSD applicant to redefine the *fundamental scope* of its project... [The redefining the source] argument has no merit in this case.
EPA regulations define major stationary sources by their product or purpose (e.g., "steel mill," "municipal incinerator," "taconite ore processing plant," etc.), not by fuel choice. Here, *Hibbing will continue to manufacture the same product (i.e., taconite pellets) regardless of whether it burns natural gas or petroleum coke*... The record here indicates that there are other taconite plants that burn natural gas, or a combination of natural gas and other fuels. Thus, it is reasonable for Hibbing to consider natural gas as an alternative in its BACT analysis. *Id.* (parentheticals original, emphasis added).

[49] In addition to simply being wrong, the NSR Manual's application of the "redefining the source" policy is due no deference because it conflicts with the agency's prior interpretations. *See Pauley v. Beth-Energy Mines*, 501 U.S. 680, 698 (1991) (no deference to agency interpretations that are inconsistent with previously held view); *see also Malcomb v. Island Creek Coal Co.*, 15 F.3d 364, 369 (4th Cir. 1994) (deference is not due to an agency interpretation of its own rules that is inconsistent); Brotherhood of *Locomotive Engineers v. Atchison, Topeka Santa Fe R.R. Co.*, 116 S.Ct. 595, 133 L.Ed.2d 535 (1996). Other Supreme Court precedent confirms that "Chevron deference" is not due to an agency's interpreations of the statutes that it operates under when such interpretations are the product of informal processes such as adoption of manual provisions rather than formal processes such as notice and comment rulemaking. *See United States v. Mead Corp.*, 120 S.Ct. 2164 (2001), *Skidmore v. Swift & Co.*, 323 U.S. 134 1944).

[50] "The assertion, and finding, that the design is for reasons independent of air quality permitting must be reasonable and supported by the record." *Prairie State* at 34 n.29. For Dry Fork, however, WYDEQ has failed to even make an evidence-based finding that IGCC is incompatible with the purpose of the project. This is both substantively inadequate and inadequate as a matter of public notice —it is arbitrary and capricious.

For Dry Fork, WYDEQ has articulated no such rationale.[51] As discussed above, this position is simply untenable as a matter of statutory interpretation. Moreover, it also runs counter to the EAB's favorable consideration of Illinois EPA's requirement for permit applicants to consider IGCC.

In *Prairie State*, the Petitioners argued that the scope of EPA's "redefining the source" policy lacked any "principled standards," and would therefore allow permit applicants to define-away basic elements of the BACT analysis. *See Prairie State* at 33. The EAB rejected this argument, but in doing so relied specifically on Illinois EPA's policy of requiring consideration of IGCC to demonstrate why the policy was not fatally overbroad.[52] *Id.* 33-37. The Board noted that Illinois EPA "required Prairie State to submit a detailed analysis of [IGCC] as a method for controlling emissions from the proposed Facility." *Prairie State* at 35.[53] The Board explained, "IGCC is not simply an add-on emission control technology, but instead would have required a completely redesigned 'power block.' . . . [Illinois EPA's] demand that Prairie State provide a detailed analysis of IGCC, which [Illinois EPA] noted has the promise to achieve greater [emissions] reductions, demonstrates that [Illinois EPA's] application of the policy against redefining the design of the source through application of BACT did not treat "very few" design changes as consistent with the proposed Facility's basic design. . . . To the contrary, [Illinois EPA's] consideration of IGCC demonstrates that [it] gave due regard to Prairie State's objective in submitting a permit application for the proposed Facility, namely development of an electric power generating plant that would be co-located and co-permitted with a 30-year supply of fuel, and then explored every potential add-on technology and potentially lower-emitting production processes or methods consistent with that basic design to determine the maximum emissions reductions achievable for the Facility." *Id* at 35-36.[54]

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[51] In addition to rendering this part of the BACT analysis inadequate, WYDEQ's failure to specifically identify why IGCC was not evaluated in the BACT analysis has deprived commentors of WYDEQ's essential rationale for a major part of its decision. Accordingly, WYDEQ must describe the basis for its determination and provide the public with an opportunity to comment on its rationale.

[52] If the EAB affirmed Illinois EPA's authority to require consideration of IGCC, such consideration must be within the permitting authority's discretion under the statutory definition of BACT, and therefore cannot be a fundamental "redefinition" of the source that is impermissible under the Clean Air Act.

[53] The Board references a letter from Donald Sutton, Illinois EPA to Diana Tickner, Prairie State (March 29, 2003), that letter is incorporated by reference here.

[54] In its analysis, the Board specifically recognized that EPA guidance requires consideration of process-related technology advances like IGCC. *Prairie State* at 33 ("The NSR Manual also states with respect to production processes, that where 'a given production process or emission unit can be made to be inherently less polluting' 'the ability of design considerations to make the process inherently less polluting *must be considered* as a control alternative for the source.'"). The Board went on to explain that "viewing the proposed facility's basic design as something that generally should not be redefined through BACT review does not prevent the permit issuer from taking a 'hard look' at whether the proposed facility may be improved to reduce its pollutant emissions." *Id* at 33-34. By "hard look" it is clear that the Board means a real, substantive BACT examination that explains in detail the technological, engineering, process, and/or design factors that make a particular emission control option incompatible with the projects objectives. *See Prairies State* at 34 (citing *Knauf*, 8 E.A.D. 121, 127 (EAB 1999)). The Board explained that a permit issuer's failure to take a sufficiently hard look at the design issues has "the potential to circumvent the purpose of BACT, which is to promote use of the best control technologies as widely as possible." *Prairie State* at 34 (quoting *Knauf*, 8 E.A.D. at 140). Significantly, the EAB gave short shrift to EPA's essentially meaningless "alternatives analysis" which would have relegated consideration of any process, technique or alternative approach to pollution control to an analysis separate and apart from the BACT determination. WYDEQ's treatment of IGCC in the Dry Fork case is a perfect illustration of the danger that the EAB identified as inherent in the concept of a "redefining the source" exemption – WYDEQ has not taken a "hard look" at whether

In contrast, for the Dry Fork facility, WYDEQ has completely abrogated its BACT-related responsibilities when it comes to identifying "every potential add-on technology *and potentially lower-emitting production processes or methods* consistent with that basic design to determine the maximum emissions reductions achievable."

While the Board ultimately concluded in *Prairie State* that IGCC was not required at the facility, that determination resulted from the Board's conclusion that IGCC was essentially equivalent to the proposed boiler technology in terms of its potential emission control effectiveness. *See Prairie State* at 47. That conclusion was the unfortunate result of a poor record. As discussed at length below, it is very clear that IGCC is capable of achieving a level of emissions performance for virtually every regulated PSD pollutant that is significantly better than the performance of a PC boiler.[55] Moreover, as discussed already, IGCC plants have a multitude of collateral environmental benefits: they provide opportunity for higher reductions in hazardous air pollutants like mercury, they produce less solid waste, they use less water, and they both emit less CO_2 and provide the ability to capture CO_2 emissions for permanent storage to help address global warming. Accordingly, the Board's justification for rejecting IGCC in Prairie State was based on solely on the facts of that case, which as will be shown below are simply inapplicable to the Dry Fork plant.[56]

Indeed, EPA itself has publicly recognized IGCC as an "inherently low-polluting process/practice,"[57] and has reaffirmed its view that IGCC is an available method for cleaning and treating coal to remove air pollutants prior to combustion:

> One approach to controlling SO_2 emissions from steam generating units is to limit the maximum sulfur content in the fuel. This can be accomplished by burning... a fuel that has been pre-treated to remove sulfur from the fuel... There are two ways to pre-treat coal before combustion to lower

IGCC might be an appropriate consideration under the BACT analysis here, and WYDEQ's decision in this regard threaten to "circumvent the purpose of BACT."

55 The PSD permit application for Nueces Syngas, LLC for example, includes emission limits for the IGCC turbines (in lb/MMBTU) of 0.018 for NO_x, 0.017 for SO_2, 0.037 for CO, 0.003 for VOC, 0.006 for PM and PM_{10}, and 0.001 for H_2SO_4. There are other recent permit applications in the record that also demonstrate the tremendous opportunities for emission reductions with IGCC. Moreover, this technology is now a viable and ready option for electric power production, as evidenced by among other things the 25 or so proposed IGCC plants around the country. See the Department of Energy's document: Tracking New Coal-Fired Power Plants, available at: http://www.netl.doe.gov/coal/refshelf/ncp.pdf.

56 Moreover, to the extent that Basin Electric or WYDEQ is concerned about cost implications of IGCC, the technological availability or reliability of the technology, or other technological or economic considerations, the appropriate mechanism to address those concerns is the BACT top-down analysis – not through up-front exclusion of the technology from consideration.

57 *See, e.g.*, Robert J. Wayland, U.S. EPA Office of Air and Radiation, OAQPS, "U.S. EPA's Clean Air Gasification Activities", Presentation to the Gasification Technologies Council Winter Meeting, January 26, 2006, slide 4; and "U.S. EPA's Clean Air Gasification Initiative", Presentation at the Platts IGCC Symposium, June 2, 2005, slide 11 (citing the "inherently lower emissions of nitrogen oxides, sulfur dioxides, and mercury," as among the "fundamental advantages" of IGCC). Mr. Wayland also correctly notes that IGCC units use less water, and produce fewer global warming pollutants than conventional pulverized coal units, another point relevant to the statutory directive to "take into account environmental . . . impacts" in determining BACT limits. Wayland January 26, 2005 Presentation, Slide 4; 42 U.S.C. § 7479(3).

sulfur emissions: Physical coal cleaning and gasification... Coal gasification breaks coal apart into its chemical constituents (typically a mixture of carbon monoxide, hydrogen, and other gaseous compounds) prior to combustion. The product gas is then cleaned of contaminants prior to combustion. Gasification reduces SO_2 emissions by over 99 percent.[58]

As a result of fuel cleaning, IGCC units "will inherently have only trace SO_2 emissions because over 99 percent of the sulfur associated with the coal is removed by the coal gasification process." 70 Fed. Reg. at 9715.[59]

Because the Clean Air Act and implementing regulations clearly require evaluation of technologies like IGCC which can achieve the statutory intent of reducing emissions through process changes, available methods and systems and techniques, innovative combustion techniques, and fuel cleaning, and because WYDEQ failed entirely to conduct an analysis of IGCC as a possible control option, the proposed Dry Fork permit is unlawful and the public has unlawfully been deprived of the opportunity to meaningfully engage with the agency on this issue. Therefore, the draft permit must be withdrawn, and WYDEQ must evaluate in detail the potential for applying IGCC and make its determination and its justification available for public comment.

Recent State Actions Requiring Consideration of Cleaner Coal Technology Establish Irrefutable Precedence for the Consideration of IGCC.

In recent PSD permitting actions implementing the Federal PSD permitting program (either through a direct delegation from EPA or via approval of equivalent state rules in a state implementation plan (SIP)), several states have required consideration of IGCC in the BACT review process for new coal-fired power plants. These state decisions implementing the federal PSD program validate the plain language of the definition of BACT described above.

Specifically, in March 2003, the State of Illinois required the applicant for a proposed circulating fluidized bed (CFB) coal-fired electric generation facility to conduct a robust analysis of IGCC as a core element of its BACT analysis:

> Additional material must be provided in the BACT demonstration to address Integrated Gasification Coal Combustion (IGCC) as it is a `production process' that can be used to produce electricity from coal. In this regard, the Illinois EPA has determined that IGCC qualifies as an alternative emission control technique that must be addressed in the BACT demonstration for the proposed plant. In addition, based on the various demonstration

[58] U.S. EPA, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, 70 Fed. Reg. 9706, 9710-11 (February 28, 2005).
[59] Indeed, IGCC is a prime example of "fuel cleaning" (which also is a required BACT consideration under the Act) – involving the *pre-combustion* transformation of otherwise dirty coal into a fuel (syngas) that can be more cleanly burned in a combined-cycle power block.

projects that have been completed for IGCC, the Illinois EPA believes that IGCC constitutes a technically feasible production process.

Accordingly, Indeck must provide detailed information addressing the emission performance levels of IGCC, in terms of expected emissions rates and possible emission reductions, and the economic, environmental and/or energy impacts that would accompany application of IGCC to the proposed plant. This information must be accompanied by copies of relevant documents that are the basis of or otherwise substantiate the facts, statements and representations about IGCC provided by Indeck. In this regard, Indeck as the permit applicant is generally under an obligation to undertake a significant effort to provide data and analysis in its application to support the determination of BACT for the proposed plant.[60]

In an ensuing letter, the State of Illinois then formally informed EPA that Illinois has "concluded that it is appropriate for applicants for [proposed coal-fired power plants] to consider IGCC as part of their BACT demonstrations."[61]

Similarly, the Georgia Department of Natural Resources, in a March 2002 letter regarding the permit application of Longleaf Energy Station, also relied, in part, on the failure of the permit applicant to consider cleaner coal combustion technology in finding the application deficient. In making its determination of deficiency, Georgia stated that the applicant did not "discuss any other methods from generating electricity from the combustion of coal, such as pressurized fluidized bed combustion or integrated gasification combined cycle."[62] Georgia further stated that the applicant "should discuss these technologies and explain why you elected to propose a pulverized coal-fired steam electric power plant instead."[63]

Reflecting the viability of IGCC, even at high altitudes, the State of New Mexico issued a letter on December 23, 2002 requiring the permit applicant for a new coal-fired power plant to conduct a site-specific analysis of IGCC as well as CFB as part of the BACT analysis for the proposed facility: "The Department requires a site-specific analysis of IGCC and CFB in order to make a determination regarding BACT for the proposed facility." The New Mexico determination goes on to provide: "The analysis must include a discussion of the technical feasibility and availability of IGCC and CFB for the proposed site in McKinley County, including a discussion of existing IGCC and CFB systems."[64]

On August 29, 2003, New Mexico issued its evaluation of the applicant's response. New Mexico found that the applicant's BACT analysis had in fact indicated that IGCC is commercially available but that the applicant had improperly relied on cost to find that the technology was infeasible:

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[60] Letter from Illinois Division of Air Pollution Control to Jim Schneider, Indeck-Elwood, LLC (March 8, 2003), Attachment 3 .

[61] Letter from Illinois EPA Director to EPA Regional Administrator, Region V (March 19, 2003), Attachment 4.

[62] Letter from James A. Capp, Manager, Stationary Source Permitting Program, Georgia DNR, to D. Blake Wheatley, Assistant Vice President, Longleaf Energy Associates, LLC (March 6, 2002). Attachment 5.

[63] *Id.*

64 Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Corporation (Dec. 23, 2002). Attachment 6.

Mustang concludes that neither IGCC nor CFB are technically feasible control options for the Mustang site. After careful review of the revised BACT analysis, as well as information gathered from independent sources, the Department determines that Mustang's conclusion is not supported by the evidence. Accordingly, the Department finds that Mustang has not demonstrated the technical infeasibility of IGCC and CFB. Moreover, applying the criteria in the NSR Manual, the Department determines that IGCC and CFB are technically feasible at the Mustang site, and must be evaluated in the remaining steps of the top down BACT methodology.

(a) IGCC and CFB are technically feasible at the Mustang site. A technology is considered to be technically feasible if it is commercially available and applicable to the source under consideration. *See* NSR Manual at B.17-18. A technology is commercially available if it has reached a licensing and commercial sales stage of development. *Id.* A technology is applicable if it has been specified in a permit for the same or a similar source type. *Id.* Mustang's revised BACT analysis indicates that IGCC is commercially available, and IGCC has been specified in air quality permits for coal-fired power plants. *See, e.g.,* Lima Energy Facility, 580 megawatt coal-fired power plant. Similarly, CFB is commercially available and has been specified in air quality permits for coal-fired power plants. *See, e.g.,* AES Puerto Rico 454 megawatt coal-fired power plant; Reliant Energy Seward 584 megawatt coal-fired power plant.

(b) For both IGCC and CFB, Mustang improperly relies on cost to determine technical infeasibility. A technology is technically feasible when the resolution of technical difficulties is a matter of cost. *See* NSR Manual at B.19-20. Mustang's revised BACT analysis indicates that the resolution of technical difficulties for both IGCC and CFB are a matter of cost. These costs do not support a finding of technical infeasibility, but may be considered during Step 4 of the top down BACT methodology. *See* NSR Manual at B.26.[65]

In addition, the Montana Board of Environmental Review found that the Montana Department of Environmental Quality must consider IGCC as an available technology in the BACT review for a coal-fired power plant. Specifically, the Board of Environmental Review stated ". . .the Department should require applicants to consider innovative fuel combustion techniques in their BACT analysis and the Department should evaluate such techniques in its BACT determination in accordance with the top-down five-step method."[66] Again, much of Montana is at relatively high elevations.

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[65] Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Company (Aug. 29, 2003), at p. 3, Attachment 7.

[66] Montana Board of Environmental Review, Findings of Fact, Conclusions of Law, and Order In the Matter of the Air Quality Permit for the Roundup Power Project (Permit No, 3182-00), Case No. 2003-04 AQ (June 23, 2003) at 18-19. See Attachment 8 for a copy of this finding.

It is important to note that, while some of these states were operating under SIP-approved PSD programs, the definition of BACT that applied in all cases is virtually identical to the federal definition of BACT (as is Wyoming's) with respect to consideration of inherently lower emitting processes. It is noteworthy that these states determined it was entirely appropriate, indeed necessary, to require consideration of IGCC in the BACT review for a coal-fired power plant.

The aforementioned state determinations are attached hereto.

EPA Region 8 Has Also Determined It Was Appropriate to Evaluate IGCC in the BACT Analysis for a Coal-Fired Power Plant

Further, EPA Region 8 submitted comments to the Utah Division of Air Quality in an April 6, 2004 letter on Utah's proposed permit for NEVCO Energy's Sevier Power Company Project in which EPA requested that further documentation on costs be provided to support Utah's claim that IGCC was too costly.[67] EPA did not indicate that IGCC didn't need to be considered as an alternative for the proposed Sevier CFB boiler. Instead, EPA stated "It is our understanding that IGCC is a potentially lower polluting process than Circulating Fluidized Bed combustion." EPA's comments requesting more documentation of the costs of IGCC provide strong indication that EPA found it appropriate to consider IGCC in the BACT analysis.

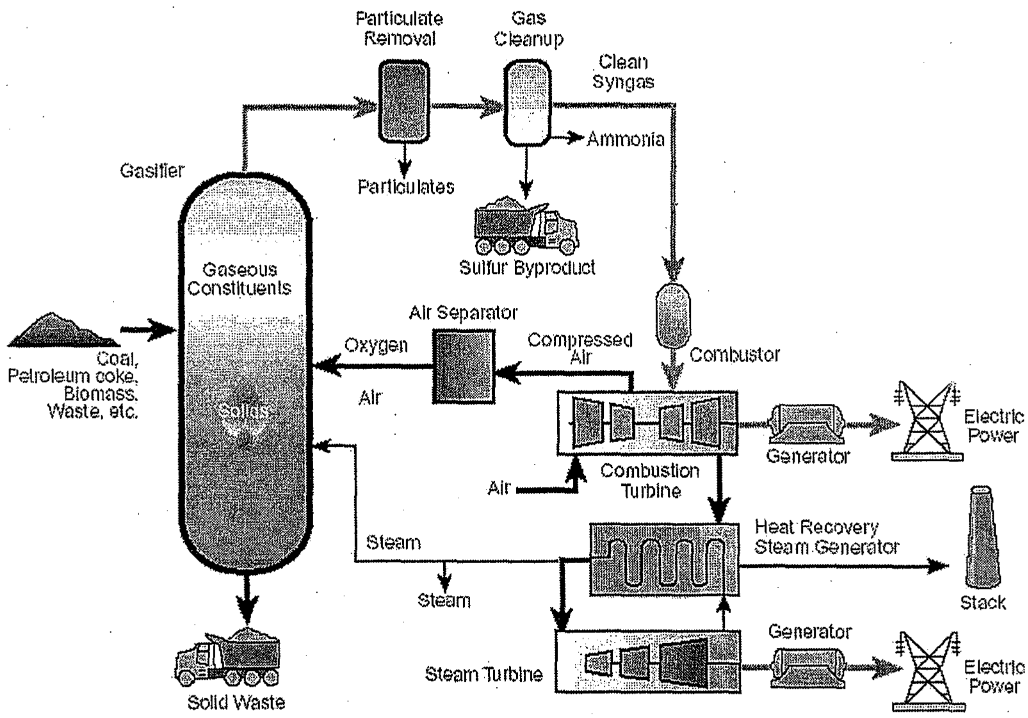
Thus, for all of the reasons described above, WYDEQ erred in failing to fully evaluate IGCC for Dry Fork in a top-down BACT review. Below we have provided an analysis of IGCC in a top-down BACT review and the results indicated that IGCC is the top technology.

5. IGCC IS AN AVAILABLE CLEAN COAL COMBUSTION TECHNOLOGY THAT MUST BE EVALUATED AS PART OF THE BACT ANALYSIS FOR DRY FORK

IGCC is an available, demonstrated clean coal combustion technology with significant emission reduction benefits. There are numerous benefits to IGCC, including fewer emissions of criteria and hazardous air pollutants, the opportunity for capturing greenhouse gases, such as CO_2, that cause global warming, and a general increase in efficiency over other coal burning technologies. However, the permit application for Dry Fork does not evaluate coal technology and instead focused solely on the construction of PC coal combustion. Because Basin Electric did not fully consider IGCC in its BACT analysis, WYDEQ must direct the applicant to thoroughly evaluate these advanced combustion options as part of the BACT analysis for Dry Fork for all of the reasons discussed above. The definitions of BACT under Wyoming and federal law, and the core requirements of the BACT analysis under federal case law, EPA adjudicatory decisions, and the NSR Workshop Manual, demonstrate that an available technique such as IGCC must be identified and evaluated as a control option in the first step of the BACT analysis. These are minimum core requirements of a state-administered PSD program.

Electricity generation from coal using IGCC technology is a commercially available and proven process. IGCC units generate electricity by integrating a coal gasifier with combined cycle (combustion turbine and steam turbine) electricity generation equipment (see figure below).

[67] April 6, 2004 letter from Richard R. Long, EPA, to Rick Sprott, Utah Division of Air Quality, at 1 (Attachment 9).



<u>Information about IGCC is Readily Available and WYDEQ is Obligated to Meaningfully Examine Such Information for Dry Fork's Permit</u>

Gasification is not a new technology, but rather one that has been around for at least a hundred years. Detailed information about the gasification process and IGCC is readily available to the utility industry and regulatory decision-makers, including EPA and WYDEQ. For example, the Gasification Technologies Council (GTC) (which "was created in 1995 to promote a better understanding of the role Gasification can play in providing the power, chemical and refining industries with economically competitive technology options to produce electricity, fuels and chemicals in an environmentally superior manner") maintains a website with copious information about gasification, IGCC, specific IGCC technologies, vendor products, and existing IGCC projects. *See* http://www.gasification.org/.[68]

Among other things, the GTC accurately explains that "Gasification offers the cleanest, most efficient method available to produce synthesis gas from low or negative-value carbon-based feedstocks such as coal, petroleum coke, high sulfur fuel oil or materials that would otherwise be disposed as waste. The gas can be used in place of natural gas to generate electricity, or as a basic raw material to produce chemicals and liquid fuels." A prime source of information is available on the GTC website including papers and presentations compiled into an on-line library

[68] The Department of Energy also has a website dedicated to gasification: http://www.netl.doe.gov/technologies/coalpower/gasification/database/database.html.

that can function as an important resource for both utilities and regulators. *See* http://www.gasification.org/library.htm. Among the important resources on this website is information about gasification generally, IGCC, and use of IGCC with low-rank coals;[69] information about the readiness of IGCC technology and the appropriateness of requiring examination of IGCC as a part of the BACT analysis;[70] information about polygeneration and capture of global warming gases from gasification plants;[71] and information about IGCC projects currently in the works.[72] Indeed, the GTC's 2006 annual conference last summer generated literally dozens of papers and presentations about gasification and IGCC technology.[73]

In the face of the remarkable wealth of available information, WYDEQ has made the clearly arbitrary decision to ignore IGCC entirely as a possible option for the proposed Dry Fork facility. Even a cursory examination would demonstrate that IGCC is a technology that has arrived and that is available *now* as an option for utilities planning new coal-based power plant projects,[74] and that information regarding the technology is readily available to appropriately inform the top-down BACT decisionmaking process.[75] Moreover, it is clear that EPA is aware that IGCC is a technology that is rapidly becoming a market force in the utility industry – for example, in July 2006 EPA issued a report entitled Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies,[76] which examined various aspects of IGCC.[77] Given the wealth of available information, the fact that WYDEQ has failed utterly to examine the possibility of employing IGCC as a technology option for the proposed Dry Fork plant is demonstrably at odds with its statutory responsibilities.[78]

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[69] http://www.gasification.org/Docs/Bismarck%2006/02Amick.pdf; http://www.gasification.org/Docs/Bismarck%2006/01Phillips.pdf.

[70] http://www.gasification.org/Docs/Tampa%2006/Ely.pdf.

[71] http://www.gasification.org/Docs/Bismarck%2006/03RJones.pdf; http://www.gasification.org/Docs/Bismarck%2006/05pan.pdf.

[72] http://www.gasification.org/Docs/Bismarck%2006/07Smet.pdf;

[73] http://www.gasification.org/Presentations/2006.htm. Additional technical information about IGCC and carbon capture and storage is available from U.S government websites, environmental organizations, and organizations like the World Energy Council (see http://www.worldenergy.org/wec-geis/focus/ccs/; http://www.fe.doe.gov/sequestration/index.html; http://www.pewclimate.org/). The fifth annual conference on carbon capture and sequestration was held this past May just outside Washington, D.C. (see http://www.carbonsq.com/).

[74] Even the utility industry is beginning to acknowledge the all-too-obvious fact that the time for IGCC has come and that the nation must begin to seriously address its carbon future. See: http://www.cleanenergypartnership.org/news/article_detail.cfm?id=231. Sadly, when it come to carbon emissions, global warming, and advance coal technologies, even the utility industry, it appears, is out in front of EPA.

[75] In addition to the tremendous amount of activity directed at refining the technology, making it cheaper, more reliable, and more commercially attractive, the fact that there are now more than 25 proposals for IGCC plants nationwide make it clear that it is an option that is technologically available. See http://www.netl.doe.gov/coal/refshelf/ncp.pdf.

[76] *See* http://www.gasification.org/Docs/News/2006/EPA%20-%20IGCC%20cf%20PC.pdf.

[77] This report however, by its own terms, was a snapshot in time of the state of IGCC, based on 2004 information – information that is now badly out of date (especially given the rapid advances being made in this dynamic field). Even from a PSD perspective, a two-year-old analysis is inadequate (PSD permits expire after eighteen months precisely because the information upon which they are predicated is expected to become stale as processes and control technologies become more effective at reducing pollutant emissions).

[78] Other information that WYDEQ should consider in its examination of IGCC for Dry Fork includes among other things:

Producing Electricity with an IGCC Facility with Add-On Pollution Controls is Inherently Less Polluting than Producing Electricity with a Pulverized Coal Facility

The coal gasification fuel-processing step in IGCC power plants results in superior environmental performance and lower emissions compared to the PC technology that is proposed for the Dry Fork power plant. Gasifying coal at high pressure prior to combustion facilitates removal of pollutants that would otherwise be released into the air. According to James Childress, "...criteria pollutant emissions for a coal-based IGCC plant are well below those of even the most modern pulverized coal plants with post combustion cleanup."[79] Mercury removal rates of greater than 94 percent can also be achieved using currently available control technologies with IGCC.[80] DOE states that "an IGCC power plant has the potential of achieving very high mercury removal performance with established technology" and mercury removal in an IGCC power plant can be expected to be very high in removal effectiveness, low in cost, and reliable in design."[81]

Table 1 summarizes the Dry Fork proposed permit emission rates with permit emission rates for an IGCC plant using the design fuel for Dry Fork. For each of the important pollutants in the BACT analysis, IGCC is the top ranked technology or is equivalent to the proposed Dry Fork emission limits.

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http://www.ciel.org/Publications/CO2_Foote_11May04.pdf (article by Greg Foote, former EPA Assistant General Council); http://www.synapse-energy.com/Downloads/SynapsePaper.2006-06.Climate-Change-and-Power.pdf (report by Synapse Energy Economics); http://www.grida.no/climate/ipcc_tar/wg2/index.htm (Climate Change 2001 Report); http://www.synapse-energy.com/Downloads/SynapseReport.2006-02.SCE.Mohave-Alternative-Generation-Resources.05-020.pdf (Synapse Mojave Report); http://www.epa.gov/climatechange/ (information available on EPA's own climate web site); http://www.publicaffairs.noaa.gov/pdf/economic-statistics-may2006.pdf (NOAA economic statistics); http://www.wvecouncil.org/issues/gambling_with_coal.pdf (Union of Concerned Scientists Report); STERN REVIEW ON THE ECONOMICS OF CLIMATE CHANGE, available at: http://www.hm-treasury.gov.uk/Independent_Reviews/stern_review_economics_climate_change/sternreview_index.cfm.

[79] Childress, James M. Statement Submitted for the Record, Senate Environment and Public Works Subcommittee on Clean Air, Wetlands and Climate Change, January 29, 2002.

[80] See, e.g., http://seca.doe.gov/technologies/coalpower/gasification/pubs/pdf/Coal%20Gasification%20Report%20-%20Chapters.pdf; http://dha.state.wi.us/home/Decisions/DNR/2005/ih0403.pdf; and http://www.netl.doe.gov/technologies/coalpower/gasification/pubs/pdf/MercuryRemoval%20Final.pdf.

[81] "The Cost of Mercury Removal in an IGCC Plant," US DOE, NETL, September 2002 at 1-2, Attachment 10.

Table 1: Comparison of Emission Rates for Dry Fork to a Recently Proposed Permit for an IGCC Plant

	Dry Fork Station PC Proposed Emission Rates (lb/MMBtu)	Christian County Generation IGCC Emission Rates* (lb/MMBtu)
NO_x	0.05 (12 month rolling)	0.0246 (24-hour average)
VOC	0.0037 (limit not in draft permit[82])	0.006
PM_{10}	0.012 (filterable)	0.0063
CO	0.15	0.036
Sulfuric Acid Mist	SO_2 limit is surrogate for BACT	0.0026
SO_2	0.08 (12 month rolling)	0.0117 (3-hour average)
Hg	0.0000102[83]	0.0000019[84]

* All IGCC emission rates for the BACT analysis are based on the November 26, 2007 proposed permit to Christian County Generation for an IGCC facility to be located in Taylorville, Illinois with the exception of the mercury emission rate. As discussed in footnote 84, the mercury emission rate is from the Christian County Generation permit application for the Taylorville IGCC facility. A copy of the proposed permit is included as Attachment 11 to this letter. The limits in the proposed permit are in terms of heat input of the syngas. We converted those limits to be in terms of heat input to the coal for a direct comparison to the proposed Dry Fork emission limits in this table.

For the limits found in Table 1 under baseload conditions, IGCC would yield significantly lower amounts of NO_x, SO_2, PM_{10}, CO, and mercury, as well as significantly lower amounts of the climate changing emissions of CO_2. As previously stated, IGCC facilities are typically more efficient than pulverized coal-fired boilers, thus producing less CO_2 compared to a PC boiler producing the same amount of electricity.[85] Furthermore, IGCC allows for an option to make even deeper cuts in carbon dioxide that conventional coal plants cannot do. The CO_2 in the syngas can be captured and sequestered at a fraction of the cost of post-combustion carbon capture and sequestration at other coal plants.

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[82] The WYDEQ Permit Application Analysis provides this limit as reflecting BACT, but the proposed permit does not include any limit for VOCs. See WYDEQ Permit Application Analysis at 14, 47.

[83] This mercury emission rate was calculated from the proposed mercury emission limit of 97 x 10^{-6} lb/MWh, assuming an efficiency of the plant of 36 percent which is the efficiency assumed by EPA in its 2005 updates to the New Source Performance Standards for electric utility steam generating units (70 Fed.Reg. 9714 (2/28/05)). It must be noted that the proposed permit also includes a mercury reduction optimization study with a target mercury emission rate of 20 x 10^{-6} lb/MWh, which is equivalent to 0.0000021 lb/MMBtu (assuming 36 percent efficiency).

[84] This is the mercury emission rate provided in the Christian County Generation permit application for the Taylorville IGCC facility. The facility will be equipped with a mercury removal system (see page 4 of the proposed permit (Attachment 11 to this letter). The Illinois EPA has only included the mercury limit of the New Source Performance Standards in the proposed permit, i.e., 20 x 10^{-6} lb/MWh.

[85] EPA's Final Report entitled "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies," at ES-7. Attachment 13.

The waste leaving an IGCC plant is vitrified, thereby potentially reducing some of the solid waste disposal issues associated with coal combustion. Indeed, IGCC plants produce 30 to 50 percent less solid waste than PC plants.[86] As discussed in great detail above, WYDEQ has a duty under federal and state law to consider the environmental impacts of the solid waste associated with different technology options.

IGCC is clearly an available method, system and technique for producing electricity from coal and thus must be fully and fairly evaluated in the Dry Fork BACT analysis. Basin Electric and/or WYDEQ must develop average and incremental costs for each pollutant removed and compare these costs to the proposed configuration of the Dry Fork facility.

6. WYDEQ AND BASIN ELECTRIC FAILED TO EVALUATE A SUPERCRITICAL BOILER IN THE DRY FORK BACT ANALYSIS

WYDEQ and Basin Electric should have also considered the construction of a supercritical or ultra supercritical PC boiler in the BACT analysis for Dry Fork.[87] Supercritical boilers are more efficient than subcritical boilers, burning 7 percent to 17 percent less coal to produce the same amount of electricity[88]. Thus, supercritical boilers emit less carbon dioxide emissions than conventional subcritical PC boilers to produce the same amount of electricity. Further, such supercritical boilers achieve up to 17 percent lower emission rates of carbon monoxide (CO), nitrogen oxides (NO_x) and sulfur oxides (SO_x), as well as up to 15 percent lower PM emission rates per unit of electricity produced.[89] This means lower overall hourly and annual rates of emissions of NO_x, SO_2 and other pollutants to the air. Such boilers also use less water and produce less waste than subcritical boilers.[90] Many recently proposed or permitted power plants will be using more efficient supercritical boilers, including the proposed Desert Rock power plant to be located in New Mexico, the proposed Unit 3 at the Intermountain Power Plant to be located in Utah (whose owners recently decided to switch from an originally planned subcritical boiler to a supercritical boiler), the White Pine and Nevada Power power plants both to be located in Nevada, the Toquop power plant to be located on the Toquop Indian Reservation, Unit 4 of the Council Bluffs Energy Center in Iowa, and Unit 3 of the Comanche power plant in Colorado. Many of these facilities will be utilizing Powder River Basin subbituminous coal. As stated by the owners of the proposed Unit 3 of the Intermountain Power Plant, supercritical boilers are "more efficient and better for the environment [and] reflects the latest engineering and market developments for [pulverized coal] facilities. . . ."[91]

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[86] Major Environmental Aspects of Gasification-Based Power Generation Technologies, US DOE, December 2002, Table 1-7, Page 1-28, Attachment 12.

[87] The permit application for Dry Fork appears to be silent on whether the facility is planned to have a subcritical or supercritical boiler, but a review of the unit net heat rate provided in Appendix B of the Dry Fork permit application (10,077 Btu/ne kWh at 100 percent load) indicates that the boiler would be a subcritical boiler.

[88] Calculated from fuel requirement data provided in Table ES-1 of EPA's Final Report entitled "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies," at ES-7. Attachment 13.

[89] See attached presentation by Tom Bartolomei, ALSTOM, *Sliding Pressure Supercritical Boilers: Flexible and Efficient Technology for New Coal-Fired Generation*, presented at COAL-GEN, August 1, 2002. Attachment 14. .

[90] EPA's Final Report entitled "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies," at ES-8. Attachment 13.

[91] August 4, 2006 letter from Utah Associated Municipal Power Systems to Utah Division of Air Quality at 1.

Thus, the Dry Fork BACT analysis is significantly flawed without evaluating supercritical boiler technology for the Dry Fork power plant. WYDEQ and Basin Electric must evaluate the installation of both a supercritical and an ultra supercritical boiler at Dry Fork as inherently lower emitting processes and a more environmentally beneficial technologies, with lower hourly and annual emissions of all pollutants including CO_2 for the same amount of electricity produced.

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7. WYDEQ'S PROPOSED BACT LIMITS FOR THE PROPOSED PULVERIZED COAL BOILER AT THE DRY FORK FACILITY ARE FLAWED.

WYDEQ's proposed BACT limits for the proposed PC boiler at the Dry Fork facility are flawed for numerous reasons, including that the averaging times of the proposed limits aren't consistent with the averaging times of the NAAQS and other PSD standards, WYDEQ has not proposed BACT limits on all regulated pollutants, and that the proposed limits fail to reflect the maximum degree of emission reduction that is achievable as required by the definition of BACT in the WAQSR (Chapter 6, Section 4(i)). Our detailed comments are as follows:

a. The Proposed BACT Emission Limits for Dry Fork Must Have Averaging Times Consistent with the NAAQS and Other PSD Standards

WYDEQ has proposed the following emission limits as reflective of BACT for the proposed PC boiler at the Dry Fork facility:

Pollutant	WYDEQ's Proposed BACT Limit
NO_x	0.05 lb/MMBtu (annual average) 190.1 lb/hr (30 day average)
SO_2	0.08 lb/MMBtu (annual average) 304.1 lb/hr (30 day average)
PM/PM_{10} (filterable)	0.012 lb/MMBtu (no averaging time indicated)
CO	0.15 lb/MMBtu (no averaging time indicated)

EPA's NSR Workshop Manual and other policy clearly state that the BACT emission limits must demonstrate compliance with the NAAQS and other PSD standards and, as such, must appropriate averaging times consistent with those standards. See EPA's NSR Workshop Manual, October 1990 Draft, at B.56. See also November 24, 1986 EPA memo with subject "Need for Short-term Best Available Control Technology (BACT) Analysis for the Proposed William A. Zimmer Power Plant," Attachment 15.

Further, emission limits reflective of BACT are to be met on a continuous basis. Specifically, Section 302(k) of the Clean Air Act expressly defines the term "emission limitation" as a limitation on emissions of air pollutants "on a continuous basis." Section 169(3) of the Clean Air Act, in turn, defines BACT as an "emission limitation." Accordingly, the Clean Air Act mandates that BACT continuously limit emissions of air pollutants. BACT emission limits over annual averaging times or over 30 day averaging times do not effectively ensure that the control technology will be used to limit emissions of air pollutants to the maximum extent achievable on a continuous basis. Such long averaging times will allow Basin Electric to operate the Dry Fork facility at uncontrolled emission rates for some periods and still comply with the proposed annual average or 30 day average emission limits.

Accordingly, WYDEQ must impose BACT limits with averaging times equal to or shorter than the most stringent averaging time of the NAAQS or PSD standards for each pollutant. Thus, this means the SO_2 BACT limit must be based on a 3-hour averaging time, the PM_{10} limit must be based on a 24-hour averaging time, and the CO limit must be based on an 8-hour averaging time.

Further, in assessing compliance with visibility protection requirements in Class I areas, visibility impacts are assessed over a 24-hour averaging period. Accordingly, the BACT emission limits for all pollutants modeled in the Class I area visibility modeling assessment must reflect a 24-hour averaging period or less. This would pertain to the BACT limits for NO_x, SO_2, and PM_{10}.

As demonstrated below in our specific comments on WYDEQ's proposed BACT limit for each pollutant, there are numerous examples of BACT limits for recently issued or proposed coal-fired power plant permits that are consistent with the policy described above. WYDEQ has no legal justification for setting BACT limits with annual or 30-day averaging times. Thus, WYDEQ must set BACT limits for Dry Fork with averaging times consistent with the shortest averaging period of the NAAQS and PSD standards applicable to each pollutant that is subject to BACT.

b. The Proposed NO_x BACT Limit Does Not Reflect the Maximum Degree of Reduction that Can Be Achieved at a Pulverized Coal-Fired Boiler

As previously cited, the WAQSR define "BACT" as follows:

> an emission limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under these Standards and Regulations or regulation under the Federal Clean Air Act, which would be emitted from or which results for any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application or production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.

Chapter 6, Section 4(i) of WAQSR [emphasis added].

The WYDEQ's proposed NO_x BACT limits do not reflect the maximum degree of reduction in NO_x emissions achievable at the proposed PC boiler at the Dry Fork facility.

WYDEQ stated that Basin Electric has proposed the top control technologies of low NO_x burners with overfire air and selective catalytic reduction (SCR) to control NO_x.

WYDEQ Permit Application Analysis, NSR –AP-3546, February 5, 2007, at 5. Then WYDEQ apparently evaluated entries in the EPA's RACT/BACT/LAER Clearinghouse and evaluated actual emissions data from several Texas coal-fired electrical generating units to determine emission rates reflective of NO_x BACT for Dry Fork. Consideration of this type of data is extremely important in a BACT determination, but WYDEQ should have also gathered and considered other available data on pollution reduction capabilities from control technology vendors, consultants, and technical journals and reports. See NSR Workshop Manual, October 1990 Draft, at B.11.

First, Basin Electric indicated that the outlet NO_x emission rate expected from the Dry Fork boiler would be 0.20 to 0.25 lb/MMBtu. November 10, 2005 Application for Permit to Construct Dry Fork Station Project at 2-8. However, technical papers and vendor information indicate that much lower NO_x emission rates can be achieved with current state-of-the-art low NO_x burners and overfire air. For example, available vendor information for ultra low NO_x burners with overfire air indicates that boiler outlet NO_x emission rates of 0.17 lb/MMBtu or lower can be met at boilers burning subbituminous coal from the Powder River Basin.[92] Another study conducted by Babcock & Wilcox at tangentially-fired units burning subbituminous Powder River Basin coal showed NO_x emission rates with ultra low NO_x burners and overfire air that were generally less than 0.13 lb/MMBtu.[93] Basin Electric has indicated that the planned PC boiler at Dry Fork will be either tangentially-fired or wall-fired. See November 10, 2005 Application for Permit to Construct Dry Fork Station Project at 2-5. Even with a wall-fired boiler burning subbituminous coal, similar low NO_x emission rates have been met with current state-of-the-art low NO_x burners and overfire air. For example, a study conducted at a 600 MW wall-fired subbituminous coal burning boiler found that NO_x emission rates of 0.15 lb/MMBtu or lower (as low as 0.138 lb/MMBtu) were achieved with Low NO_x Dual Air Zone CCV® Burners and overfire air.[94]

Further, neither Basin Electric nor WYDEQ evaluated the maximum degree of NO_x reduction that can be achieved with SCR at Dry Fork. Assuming Basin Electric's claim of NO_x emission rates exiting the boiler of 0.20-0.25 lb/MMBtu (which we think is too high, as discussed above), the NO_x BACT emission limit proposed by Basin Electric of 0.07 lb/MMBtu only reflects a 65 percent to 72 percent reduction in NO_x emissions from the SCR. WYDEQ requested that an emission limit of 0.05 lb/MMBtu be evaluated (WYDEQ Permit Application Analysis, NSR – AP-3546, February 5, 2007, at 5), but this only reflects 80 percent control from the SCR. If the NO_x emission rates exiting the boiler are 0.15 lb/MMBtu or lower, which is most likely if current state-of-the-art low NO_x burners are used, then a NO_x BACT limit of 0.05 lb/MMBtu only reflects a 67 percent NO_x reduction from the SCR. Yet, SCR systems can reduce NO_x emissions by 90 percent or more. According to Babcock & Wilcox, commercial SCR installations have

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[92] See Bryk, S.A. et al., First Commercial Application of DRB-4Z™ Ultra-Low NO_x Coal-Fired Burner, presented to POWER-GEN International 2000, November 14-16, 2000, Orlando, FL. Attachment 16.

[93] See Whitfield, T. et al., Comparison of NO_x Emission Reductions with PRB and Bituminous Coals in 900 MW Tangentially-Fired Boilers, presented to EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollutant Control Mega Symposium, May 19-22, 2003, Washington, D.C. at 8. Attachment 17.

[94] See Penterson, Craig A., Reducing NO_x Emissions to Below 0.15 lb/10^6 Btu on a 600 MW Utility Boiler with Combustion Control Only, presented to EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollutant Control Mega Symposium, May 19-22, 2003, Washington, D.C. Attachment 18.

shown that 90 percent NO_x reductions can be achieved with low ammonia slip.[95] Indeed, Babcock & Wilcox states that up to 95 percent NO_x control can be achieved with SCR.

Using Basin Electric's projections of NO_x emissions exiting the boiler of 0.20 to 0.25 lb/MMBtu, 90 percent control with the SCR system would equate to a NO_x emission rate of 0.020 to 0.025 lb/MMBtu. However, as shown above and in the attached documents, a NO_x rate exiting of the boiler of 0.15 lb/MMBtu (or lower) can be achieved with state-of-the-art ultra low NO_x burners and overfire air at a subbituminous coal-fired PC boiler. Thus, with 90 percent control with SCR, a NO_x emission rate of 0.015 lb/MMBtu could be met. WYDEQ failed to require Basin Electric to evaluate either of these NO_x emission rates, and thus WYDEQ failed to require Basin Electric to evaluate the maximum degree of NO_x emission reduction that can be achieved, as required by the WAQSR BACT rules.

Further, the lb/MMBtu NO_x BACT limit for Dry Fork must apply on a shorter averaging time than the proposed 12-month rolling average limit. Not only is it important for the averaging time of the BACT limit to be equal to or shorter than the most stringent averaging time of the NAAQS or PSD standards (which in the case of NO_x means at least a 24-hour averaging time to be consistent with the Class I area visibility modeling), but the averaging time of the BACT limit must be consistent with the BACT requirement that the limit be based on the maximum degree of reduction that can be achieved. A long averaging period such as the WYDEQ's proposed 12-month rolling average does not require that Basin Electric operate its NO_x pollution control equipment in a manner consistent with achieving the maximum reduction in emissions on a continuous basis. Further, a rolling 12 month average NO_x BACT limit simply does not provide much compliance incentive when, at most, Basin Electric could be liable for only 12 violations of the limit per year. A rolling 30-day average limit provides much more compliance incentive with up to 365 violations per year. A 24-hour average limit provides a similar level of compliance incentive and more definitely ensure that the pollution control equipment will be operated to provide the maximum emission reduction achievable on a continuous basis.

While WYDEQ has also proposed a 30-day rolling average BACT limit of 190.1 lb/hr, this limit only ensures that an emission level of 0.05 lb/MMBtu will be met when the unit is operating at maximum heat input capacity. When the unit is operating at less than maximum heat input capacity, the proposed 30-day average lb/hr limit will allow emission levels higher than 0.05 lb/MMBtu. Thus, to more effectively ensure that the maximum degree of reduction in emissions will be met on a continuous basis, the lb/MMBtu BACT limit should apply on a shorter averaging time than the proposed 12-month rolling average.

It is for these reasons that annual average or even 12-month rolling average NO_x BACT limits are virtually unheard of in any recent PSD permitting actions for new coal-fired power plants. At most, NO_x BACT limits have been imposed with rolling 30-day averaging times, and more commonly, NO_x BACT limits have been imposed over a 24-hour averaging time to be consistent with the visibility modeling as required by EPA's NSR Workshop Manual, and the underlying protections applicable to Class I areas.

[95] See Bielawski, G.T., J.B. Rogan, and D.K. McDonald, How Low Can We Go? Controlling Emissions in New Coal-Fired Power Plants, Presented to the U.S. EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Symposium: "The Mega Symposium," August 2001. Attachment 19.

While WYDEQ has proposed a lower NO_x BACT limit than has typically been required in recent PSD permitting actions for new coal-fired power plants, that does not justify a longer averaging time. Indeed, WYDEQ's own research found that such a limit was being met on a shorter averaging time. WYDEQ Permit Application Analysis at 5. As we have shown above, even lower emission limits could be met with ultra low NO_x burners, overfire air, and an SCR system operated to achieve the maximum degree of reduction in NO_x emissions that is achievable.

Thus, for all of the above reasons, WYDEQ must revise the proposed NO_x BACT limit for Dry Fork to be reflective of the maximum degree of NO_x reduction that can be achieved. Further, the revised NO_x BACT limit must be based on an averaging time that requires the NO_x control equipment to be operated to achieve the maximum amount of continuous reduction in NO_x emissions that is achievable.

c. The Proposed SO_2 BACT Limit Does Not Reflect the Maximum Degree of Reduction that Can Be Achieved at a Pulverized Coal-Fired Boiler

WYDEQ has proposed a SO_2 BACT limit for Dry Fork of 0.08 lb/MMBtu, 12-month rolling average, and 304.1 lb/hr (which is equivalent to the 0.08 lb/MMBtu emission limit when the facility is operating at maximum heat input capacity), 30-day average. Neither WYDEQ nor Basin Electric has sufficiently demonstrated that these emission limits reflect the maximum degree of SO_2 emission reduction that is achievable at the proposed Dry Fork facility.

First, WYDEQ notes that the Newmont Nevada TS power plant has a lower SO_2 BACT emission limit. Specifically, the Newmont PSD permit has an SO_2 limit of 0.065 lb/MMBtu that applies on a 24-hour averaging time, along with a SO_2 removal efficiency requirement of 91 percent, when combusting coal with less than 0.45 percent sulfur. The Newmont facility will be burning subbituminous coal from the Powder River Basin. Basin Electric's statements that it could not obtain a vendor guarantee for an SO_2 emission rate of less than 0.08 lb/MMBtu when another similar plant burning similar coal and using similar pollution control equipment apparently *could* obtain a vendor guarantee for a lower emission limit (or, at the least, Newmont Nevada has not appealed its PSD permit that requires the power plant to meet these lower SO_2 emission limits) provides ample reason why it is not appropriate to only rely on vendor guarantees obtained by a permit applicant in determining BACT emission limits for a facility. As EPA states in the NSR Workshop Manual, ". . .lack of a vendor guarantee by itself does not provide sufficient information that a control option or an emissions limit is technically infeasible." EPA's October 1990 Draft NSR Workshop Manual at B.20.

The Newmont Nevada BACT requirements should not only set precedent for Dry Fork in terms of the emission limits but also in terms of averaging time and the SO_2 removal efficiency required. The Newmont Nevada TS Power facility SO_2 BACT emission limits are 0.065 lb/MMBtu, 24-hour average, and a minimum of 91 percent control, 30 day average, when burning coal with sulfur content less than 0.45 percent. When burning coal with sulfur content equal to or greater than 0.45 percent, the SO_2 BACT emission requirements are 0.09 lb/MMBtu, 24-hour average basis, and a minimum of 95 percent control, 30 day average basis. See

Attachment 20 with May 5, 2005 Newmont Nevada Energy Investment Class I Air Quality Operating Permit to Construct. WYDEQ's proposed SO_2 BACT limit of 0.08 lb/MMBtu that would apply on a 12-month rolling average is nowhere near as stringent as the Newmont limits. Even when coal with 0.45 percent sulfur content or greater is burned, the proposed Dry Fork limit of 0.08 lb/MMBtu with its long 12-month averaging time is not as stringent as the 24-hour average limit of 0.09 lb/MMBtu that applies to the Newmont Nevada TS Power Plant. Further, the WYDEQ's proposed limit only reflects 93.3 percent removal from the worst case uncontrolled emission rate expected at Dry Fork[96], as compared to the minimum 95 percent SO_2 removal requirement that applies when Newmont Nevada TS Power is burning coal with more than 0.45 percent sulfur content. The proposed 0.08 lb/MMBtu limit at Dry Fork only reflects 90 percent control from the average uncontrolled SO_2 emission rate expected at Dry Fork.[97] Worse yet, the proposed Dry Fork SO_2 BACT limit only reflects 86.7 percent control from the lowest uncontrolled SO_2 emission rate expected at Dry Fork, as compared to the minimum 91 percent removal efficiency that is required at the Newmont Nevada TS Power plant *in addition to* the Newmont facility being required to comply with a 24-hour average limit of 0.065 lb/MMBtu.[98, 99]

The cost analysis provided by WYDEQ in its Permit Application Analysis is of little importance given that much more stringent SO_2 requirements have been required as BACT at the Newmont Nevada TS power plant - a facility that will be equipped with similar SO_2 control technology and will be burning similar coal to Dry Fork. As EPA states in its NSR Workshop Manual, "In the absence of unusual circumstance, the presumption is that sources within the same category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category."[100] Neither WYDEQ or Basin Electric have provided any indication of unusual circumstances at Dry Fork that would make this facility unable to meet the same emission limits as those at the Newmont Nevada TS power plant, with possibly the lone exception being that Basin Electric's statements that they can't obtain vendor guarantees for emission rates less than 0.08 lb/MMBtu which, as discussed above, is unpersuasive.

In addition to the proposed Dry Fork SO_2 limits being less stringent than the Newmont Nevada TS power plant limits, the WYDEQ's proposed SO_2 BACT emission limit for Dry Fork also fails to reflect the degree of SO_2 reduction that can be achieved across a spray dryer/absorber. Using AP-42 emission factors to estimate the uncontrolled SO_2 emissions exiting the proposed Dry Fork boiler[101], the worst case uncontrolled emission rate would be 1.05 lb/MMBtu, the average

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[96] Uncontrolled SO_2 emission rate from Basin Electric's permit application for Dry Fork at 2-6 (Table 2-1).
[97] *Id.*
[98] *Id.*
[99] The lowest uncontrolled SO_2 emission rate expected at Dry Fork was calculated approximately 0.60 lb/MMBtu based on Basin Electric's lowest projection of sulfur content of the fuel (0.25 percent) and the highest heating value provided (8,300 Btu/lb). It must be noted that uncontrolled emission rates of this level or even lower are commonly found in Powder River Basin coal, as is shown in the attached 2000 Directory of Power Plants Burning Wyoming Coal which was obtained from the Wyoming Geological Survey. (Attachment 21).

[100] See EPA's New Source Review Workshop Manual, October 1990 Draft, at B.29.
[101] The uncontrolled SO_2 emission rates provided in Basin Electric's permit application for Dry Fork at 2-6 (Table 2-1) are based on the sulfur content of the coal and do not reflect the fact that some of the sulfur will be removed as bottom ash via combustion of the coal in the boiler.

would be 0.72 lb/MMBtu, and the lowest uncontrolled emission rate would be 0.53 lb/MMBtu.[102] Thus, the WYDEQ's proposed 0.08 lb/MMBtu emission limit would only reflect a 92.4 percent SO_2 removal efficiency across the spray dryer/absorber at best, an 88.9 percent SO_2 removal efficiency on average, and an 84.8 percent removal efficiency when lowest sulfur, highest heating value coal is burned. As indicated in WYDEQ's Permit Application Analysis, Basin Electric has indicated that the "lowest emission guarantee available *for SDA [spray dryer/absorber]* is 94 percent." (WYDEQ Permit Application Analysis at 11 (emphasis added). There is ample indication in PSD permit applications that spray dry absorbers can achieve at least 90 percent SO_2 removal even with low sulfur coals.[103] Indeed, as found by EPA in its review of the New Source Performance Standards for coal-fired electric utility boilers, a spray dryer/absorber can generally achieve greater than 90 percent SO_2 removal. See 70 Fed.Reg. 9711 (February 28, 2005).

WYDEQ must also take into account other impacts in setting BACT including environmental impacts. In the case of Dry Fork, this facility will contribute to SO_2 increment violations at the Northern Cheyenne Indian Reservation Class I area. Although WYDEQ claims the facility's impacts will be less than the proposed "Class I significant impact levels," that is irrelevant for two reasons: First, the Class I significant impacts levels are not authorized in any state PSD regulation. Second, even if use of such significant impact levels were authorized under state law, EPA Region VIII has previously indicated that *any* impact in an area with existing increment violations must be considered significant.[104] WYDEQ has known about these predicted SO_2 increment violations at Northern Cheyenne Indian Reservation at least since the permitting of Wygen 3. In addition, Basin Electric's modeling also showed that total sulfur deposition linked to the Dry Fork Station would exceed the Federal Land Managers' (FLM) deposition analysis thresholds (DATs) at Wind Cave National Park and at the Northern Cheyenne Indian Reservation. Further, Basin Electric's modeling that followed FLM modeling procedures also indicated that Dry Fork could cause noticeable changes in visibility (i.e., a greater than 5 percent change) at Wind Cave National Park and at the Northern Cheyenne Indian Reservation. Thus, WYDEQ must take all of these significant environmental impacts into account in setting SO_2 BACT limits for Dry Fork.

For all of the above reasons, SO_2 BACT for Dry Fork must be at least as stringent as the SO_2 BACT emission limits required at the similarly configured proposed Newmont Nevada TS power plant, including in terms of averaging time of the BACT limits. Further, given the wide range of sulfur content of the coal, it is imperative that WYDEQ impose a SO_2 removal efficiency

[102] These emission rates were calculated using AP-42 SO_2 emission factors for dry bottom tangentially-fired or wall-fired subbmituminous coal-fired NSPS boilers (Table 1.1-3 of Chapter 1.1 of AP-42) and the worst case, best case, and average coal characteristic data provided in Basin Electric's permit application for Dry Fork (at 2-6 (Table 2-1)).

[103] For example, two recently permitted circulating fluidized bed boilers – Gascoyne (to be located in North Dakota) and Sevier (to be located in Utah) will have add-on spray dryers that reduce SO_2 by approximately 90 percent from the gas stream exiting the circulating fluidized bed boiler, and the gas stream exiting the boiler will already reflect 90 percent SO_2 removal. For Gascoyne, the inlet to the scrubber is expected to be 0.348 lb/MMBtu and the required outlet emission limit is 0.038 lb/MMBtu. See Attachment 22 with Appendix C of the Gascoyne Permit Application at page C-29.

[104] See April 12, 2002 letter from EPA, Region VIII to the North Dakota Department of Health, Attachment 23.

requirement in addition to an SO_2 emission limit to ensure that the control equipment will be operated to achieve the maximum degree of emission reduction over all of the varying levels of uncontrolled SO_2 emissions expected at the Dry Fork facility. It is also important to note that there are no exemptions from the SO_2 BACT limits in the Newmont Nevada TS power plant permit. Thus, there is also absolutely no justification for adding a safety margin to the limits that have been imposed at the similarly configured Newmont Nevada TS power plant. WYDEQ must revise its proposed BACT emission limit for Dry Fork and impose emission limitations and requirements that ensure the maximum degree of reduction in SO_2 emissions that can be achieved with the spray dry/absorber will actually be achieved at Dry Fork.

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c. The Proposed Mercury BACT Limit Does Not Reflect the Maximum Degree of Reduction that Can Be Achieved at a Pulverized Coal-Fired Boiler

WYDEQ has proposed a mercury BACT limit for Dry Fork of 97×10^{-6} lb/MWh on a 12-month rolling average, which is equivalent to the limit that applies under the New Source Performance Standards. WYDEQ's proposed permit also requires Basin Electric to undertake a mercury reduction optimization study with a target emission rate of 20×10^{-6} lb/MWh, and to install "a mercury control system." Based on the optimization study, the mercury limit would be revised.

WYDEQ provided no justification for this approach to setting mercury BACT in its permit application analysis. Instead, WYDEQ should have followed a top-down approach and set a mercury BACT emission limit that reflects the maximum degree of mercury reduction that is achievable considering energy, economics and environmental issues.

Sorbent injection *is* an available mercury control technology that could be utilized at the Dry Fork facility, and yet WYDEQ did not require full evaluation of sorbent injection in the BACT analysis. Basin Electric mentioned installation of a sorbent injection system and even stated it would leave space available for installation of such a system. Dry Fork Permit Application at 5-21. Basin Electric made no claims that the technology was not available in its permit application. Indeed, there is a wealth of information indicating that sorbent injection is an available and effective control measure for reducing mercury emissions.

For example, the owners of two new coal-fired power plants in Montana have agreed to use activated carbon injection for mercury control (i.e., the Hardin and Roundup power plants[105]). Both of these facilities will burn subbituminous coal similar to Dry Fork. Activated carbon injection has also been required by the state of Iowa at the coal-fired Unit 4 at the Council Bluffs Energy Center which will burn subbituminous coal from the Powder River Basin.[106] Also, the Newmont Nevada's TS power plant will be equipped with a sorbent injection system.[107] The proposed White Pines power plant in Nevada, which will primarily burn Powder River Basin subbituminous coal, is planned to be equipped with a halogenated activated carbon injection

[105] See December 8, 2005 Air Quality Permit for the Roundup Power Project (Attachment 24). See May 16, 2005 Air Quality Permit for the Hardin Generation Project (Attachment 25).
[106] The June 17, 2003 MACT permit and associated Technical Support Document for MidAmerican Energies' Unit 4 at the Council Bluffs Energy Center included as Attachment 26.
[107] See Newmont Nevada TS power plant permit included as Attachment 20 to this letter.

system for mercury control in addition to its planned criteria pollutant control technologies.[108] Not only will all of these facilities be burning subbituminous coal, but they will also be equipped with SCRs, spray dryer/absorbers and baghouses, similar to the proposed Dry Fork facility. Clearly, sorbent injection is an available technology for subbituminous coal-fired power plants, and WYDEQ should have evaluated this technology as part of the mercury BACT process. Because the costs of sorbent injection were considered reasonable for mercury control at these subbituminous coal-fired power plants, WYDEQ must also consider the costs of sorbent injection to be reasonable at Dry Fork. Use of such a mercury-specific control technology in conjunction with other criteria pollutant control technologies will undoubtedly reduce mercury to the maximum degree that can be achieved with the combustion of subbituminous coal that is planned to be used at Dry Fork.

Halogenated sorbents have been shown to be effective at removing mercury at subbituminous power plants, especially those equipped with spray dryer absorbers (SDA). The SDA may remove halogens in the flue gas that are needed for the adsorption of elementary mercury with untreated activated carbon. With a halogenated carbon injection system used for mercury control at the proposed Dry Fork facility, Basin Electric should be able to achieve 90 percent control or better with Powder River Basin subbituminous coal. Indeed, testing at the Holcomb Station Unit 1 in Garden City, Kansas, which burns Powder River Basin coal and is equipped with an SDA and a fabric filter, showed an *average* mercury removal efficiency of 93 percent with a low halogenated carbon injection rate of 1.2 pounds per million actual cubic feet (lb/MMacf).[109] Brominated powdered activated carbon (B-PAC) is a halogenated sorbent that has also shown high levels of mercury control across a range of coals. For example, full-scale tests of B-PAC at the St. Clair power plant in Detroit, Michigan, which burns at least 85 percent subbituminous coal blended with bituminous coal and is equipped with an electrostatic precipitator, showed that greater than 90 percent mercury removal could be routinely achieved.[110]

Basin Electric provided average coal mercury contents of 0.05 to 0.08 μg/g. Dry Fork Permit Application at 5-21. Assuming a unit net heat rate of 10,077 Btu/net kWh (which reflects 100 percent load as provided in the Dry Fork permit application in Appendix B under "Criteria Pollutant Potential to Emit"), these values equate to uncontrolled mercury emission rates of 62.2 to 100.2 x 10^{-6} lb/net MWh. Thus, WYDEQ's proposed mercury BACT limit of 97 x 10^{-6} lb/MW does not reflect *any* reduction in mercury emissions at Dry Fork. And, WYDEQ's proposed "target" mercury emission rate of 20 10^{-6} lb/MW (and there is no guarantee that WYDEQ will mandate this target limit in a revised permit pursuant to the mercury reduction optimization study currently proposed for Dry Fork) only reflects 68 percent to 80 percent mercury reductions. As discussed above and as has been shown by a wealth of other available information, at least 90 percent control of mercury should be achievable with a sorbent injection system for control of mercury. This level of control from the projected level of uncontrolled

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[108] See the Nevada Department of Environmental Protection's proposed permit to be issued to White Pine Energy Associates, LLC, included as Attachment 27 to this letter.
[109] Bustard, Jean *et al.*, Full-Scale Evaluation of Mercury Control Technologies with PRB Coals, presented at ICAC's Clean Air Technologies & Strategies Conference & Workshop, Baltimore, MD, March 7-10, 2005, at 3. Attachment 28 to this letter. Also available at www.adaes.com under publications.
[110] McCoy, Melanie *et al.*, "Full-Scale Mercury Sorbent Injection Testing at DTE Energy's St. Clair Station," presented at the Combined Power Plant Air Pollutant Control Mega Symposium, Washington, D.C., August 30 – September 2, 2004, at 8. Attachment 29 to this letter.

mercury emission rates equates to corresponding emission limits ranging from 6.26 to 10.02 $\times10^{-6}$ lb/net MW (based on Basin Electric's range of mercury content of the coal to be utilized at Dry Fork). Thus, mercury emission limits in the range of 6.26 to 10.02 $\times10^{-6}$ lb/net MW are the maximum mercury emission limits that WYDEQ should have evaluated as reflecting BACT for Dry Fork. WYDEQ should also require evaluation of emission limits that reflect even greater than 90 percent mercury control.

Thus, WYDEQ must revise its BACT analysis for mercury emissions at Dry Fork to fully evaluate sorbent injection systems, in addition to the planned criteria pollutant control equipment, and to impose emission limits reflective of the maximum degree of mercury reduction that can be achieved with these control systems at Dry Fork. Given the projected uncertainty in uncontrolled mercury emission rates, WYDEQ must also impose a percent reduction requirement reflective of BACT for mercury to ensure that the maximum degree of reduction of mercury achievable is continually achieved at Dry Fork. There is no adequate justification for deferring this decision on a mercury BACT emission limitation and requirement prior to any mercury control optimization studies conducted by Basin Electric. There is more than sufficient information available now for WYDEQ to impose a mercury BACT emission limit and other requirements reflective of at least 90 percent mercury reduction at Dry Fork, especially if WYDEQ imposes this mercury reduction requirement over a long averaging time as has been typical in recent PSD permits.

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d. WYDEQ Must Impose BACT Limits for Volatile Organic Compounds, Sulfuric Acid Mist, and Ammonia

Although WYDEQ determined emission limits as reflective of BACT for volatile organic compounds (VOCs), sulfuric acid mist (H_2SO_4) and ammonia, the proposed permit conditions fail to set emission limits for these pollutants. WYDEQ must impose permit limits reflective of BACT for these pollutants in the final permit for Dry Fork, consistent with the state's BACT determination provided in its Permit Application Analysis. (See pp. 14-16 and 47 of the Dry Fork Permit Application Analysis).

R7e

e. WYDEQ Failed to Propose a Visible Emission Limit Reflective of BACT at the Dry Fork Facility

The Wyoming definition of BACT explicitly states that BACT includes a "visible emission standard." Chapter 6, Section 4(i) of the WAQSR. Yet, WYDEQ has not evaluated or proposed a visible emission standard reflective of BACT for the Dry Fork facility. While WYDEQ has included the applicable opacity requirements of the New Source Performance Standards as a proposed condition of the Dry Fork permit (see Permit Application Analysis at 48, proposed Condition 11.A), this limit does not reflect BACT for a coal-fired power plant.

With a fabric filter baghouse for PM_{10} control, an opacity BACT limit should be at least 10 percent. Indeed, the recently permitted Intermountain Power Plant Unit 3 in Utah is subject to a 10 percent visible emissions limit.[111] Similarly, the Gascoyne CFB facility will also be subject

[111] See October 15, 2004 Approval Order for Unit 3 at Intermountain Power Generating Station, Condition 12, at 9 (Attachment 30).

to a 10 percent opacity BACT limit.[112] Also noteworthy is the permit for the Longview power plant in West Virginia, which will utilize a PC boiler. This permit requires both a PM continuous emission monitoring system (CEMS) to ensure compliance with its PM BACT limit *and* imposes a 10 percent opacity BACT limit.[113] Thus, WYDEQ must evaluate BACT for opacity and impose a visible emission standard on the Dry Fork facility that reflects the maximum degree of reduction achievable. Further, to ensure compliance on a continuous basis, a continuous opacity monitoring system (COMS) must be required.

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8. WYDEQ MUST IMPOSE A LIMIT ON TOTAL PM_{10} CONSISTENT WITH PM_{10} AND VISIBILITY MODELING CONDUCTED FOR DRY FORK

While WYDEQ proposed a BACT emission limit for filterable PM_{10} emissions at Dry Fork, WYDEQ has failed to propose any limit on total PM_{10} emissions, i.e., filterable plus condensable emissions. Yet, condensable PM_{10} emissions affect PM_{10} concentrations as well as visibility.[114] Indeed, WYDEQ required consideration of condensable PM_{10} emissions in the modeling analyses conducted for Dry Fork. See WYDEQ Permit Application Analysis at 22. Accordingly, WYDEQ must impose an emission limit on total PM_{10} emissions reflective of the level of PM_{10} emissions modeled for Dry Fork in its near field and far field analyses. Without such a limit on total PM_{10}, Basin Electric must be required to model condensable PM_{10} emissions at the allowable emission rates – i.e., uncontrolled emissions of these pollutants.

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9. WYDEQ MUST ADDRESS $PM_{2.5}$ IN THE DRY FORK PERMIT

WYDEQ has not addressed the $PM_{2.5}$ emissions to be emitted by the Dry Fork facility in its proposed PSD permit or permit application analysis. Yet, $PM_{2.5}$ is subject to PSD permitting requirements as a regulated pollutant. Specifically, Wyoming regulations defined "regulated NSR pollutant" to mean, among other things, "[a]ny pollutant for which a national ambient air quality standard has been promulgated and any constituents or precursors for such pollutants identified by the EPA Administrator (e.g., volatile organic compounds are precursors for ozone)." WAQSR Chapter 6, Section 4(a). EPA has promulgated a NAAQS for $PM_{2.5}$. 62 Fed. Reg. 38,652 (July 18, 1997); revised at 71 Fed.Reg. 61144-61233 (October 17, 2006). Wyoming's PSD regulations list significance levels for a number of "regulated NSR pollutants," but not $PM_{2.5}$. See definition of "significant" in WAQSR Chapter 6, Section 4(a). When a significance level has not been identified for a regulated NSR pollutant, the significance level is any emission rate over zero. See WAQSR Chapter 6, Section 4(a), subsection (ii) of the definition of "significant." Although there is no analysis in the Dry Fork permit application, the proposed permit conditions, or the permit analysis regarding $PM_{2.5}$, a facility of this size will undoubtedly be emitting $PM_{2.5}$ in substantial amounts. Consequently, Basin Electric is required to comply with all PSD requirements, including monitoring, modeling, and BACT regarding $PM_{2.5}$. WYDEQ cannot issue a PSD permit for this facility unless this criteria pollutant is properly addressed.

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[112] See Air Pollution Control Permit to Construct for Gascoyne, Condition II.A. 3), at 8 (Attachment 31).
[113] See March 2, 2004 Permit to Construct for Longview Power, Conditions A.8. and A.18., at 4, 9. (Attachment 32).
[114] See, e.g., EPA's March 31, 1994 letter to the Iowa Department of Natural Resources, Attachment 33.

We are aware that EPA issued guidance providing that sources would be allowed to use implementation of a PM_{10} program as a surrogate for meeting $PM_{2.5}$ NSR requirements. John Seitz, "Interim Implementation for the New Source Review Requirements for PM[2.5]," (October 23, 1997). The purpose of that guidance was to provide time for the development of necessary tools to calculate the emissions of $PM_{2.5}$ and related precursors, adequate modeling techniques to project ambient impacts, and $PM_{2.5}$ monitoring sites. 70 Fed. Reg. 65984, 66043 (Nov. 1, 2005). EPA has resolved most of these issues. *Id.* More importantly, the guidance clearly contravenes the regulations.

Thus, WYDEQ must require the Dry Fork facility to be subject to all PSD permitting requirements for PM2.5 emissions, including monitoring, modeling and BACT.

10. THE PROPOSED PERMIT FOR DRY FORK FAILS TO INCLUDE ANY CONDITIONS REGARDING THE DESIGN OF THE SOURCE

The proposed permit conditions provided at the end of WYDEQ's Permit Application Analysis for Dry Fork do not include any description of the Dry Fork facility or any description of how it will be designed. WYDEQ must issue a permit that is specific to the Dry Fork facility as proposed in Basin Electric's November 10, 2005 permit application. Further, the permit must specify the control equipment and emission limit that reflects BACT. Thus, the proposed permit must contain, among other things, terms identifying the type of boiler, the maximum heat input capacity of the boiler, the generating capacity of the unit, the control equipment that WYDEQ based its BACT emission limitations on, and the emission limitations that reflect BACT. Without such conditions in the permit, Basin Electric could potentially be allowed to build a very different source than what WYDEQ reviewed under its permitting regulations.

11. WYDEQ CANNOT ISSUE A PERMIT TO DRY FORK BECAUSE IT WOULD CONTRIBUTE TO VIOLATIONS OF THE SO_2 PSD INCREMENTS AT THE NORTHERN CHEYENNE INDIAN RESERVATION CLASS I AREA.

Basin Electric's modeling indicated that there are existing violations of the 24-hour average SO_2 PSD increments occurring at the Northern Cheyenne Indian Reservation Class I area (NCIR) (as discussed in WYDEQ's Permit Application Analysis at 40), and the Dry Fork facility will contribute to the increment violations. Consequently, Wyoming's PSD regulations provide that the permit for Dry Fork must be denied.

Although WYDEQ provided analyses to determine whether the Dry Fork facility's impact on the predicted increment violations would be "significant," such an approach to discounting the impacts of the Dry Fork facility are not grounded in state or federal law. Specifically, WYDEQ evaluated Dry Fork's contribution to the predicted exceedances of the SO_2 PSD increment concentrations at the NCIR Class I area, and then determined that the Dry Fork facility's impacts would not be "significant" at those receptors and time periods during which increment violations were shown to occur in the modeling analysis. (See Permit Application Analysis at 40.) It appears that, in making this determination, WYDEQ utilized the Class I significant impact levels that were proposed by EPA in a July 23, 1996 proposed rulemaking (61 Fed.Reg. 38292), but the Class I significant impact levels were never promulgated by EPA or adopted into Wyoming rules and the state implementation plan. In addition, EPA has previously made clear that, in an area with existing increment violations, *any* impact by a new source is considered to contribute to those increment violations. Specifically, EPA Region VIII stated in an April 12, 2002 letter to the North Dakota Department of Health that the use of significant impact levels to allow a PSD permit to be issued in the case of an area showing increment violations is not consistent with the intent of the Clean Air Act's PSD program.[115] In addition, EPA's longstanding contemporaneous interpretation of the statutory and regulatory provisions for the PSD increments clearly mandate that, in an area with existing PSD increment violations, the violations "must be entirely corrected before PSD sources which affect the area can be approved." (See 45 Fed.Reg. 52678, August 7, 1980). WYDEQ has known about these existing SO_2 increment violations at least since the permitting of Wygen 3. Thus, because the Dry Fork facility will contribute to the violations of the 24-hour SO_2 increment at NCIR, Wyoming and federal law prohibit issuance of this permit to the Dry Fork facility.

Specifically, Wyoming regulation mandates that a cumulative impacts increment analysis be conducted by a PSD permit applicant to determine the "total deterioration of air quality from the baseline concentrations" and that a permit can only be issued "if the predicted impact (over and above the baseline concentration) of emissions. . .is less than the maximum allowable increment shown in Table 1 [of Chapter 6, Section 4 of the WAQSR] for the classification of the area in which the impact is predicted. . . ." WAQSR Chapter 6, Section 4(b)(i)(A)(I). Further, Wyoming's regulations also provide that no permit can be issued unless the permit applicant shows that it won't emit pollutants "in amounts [which] will. . . interfere with measures required by the
Federal Clean Air Act to be included in the applicable Implementation Plan for any other state to prevent significant deterioration of air quality. . . ." WAQSR, Chapter 6, Section 2(c)(viii)(ii).

It also appears that Basin Electric's cumulative Class I SO_2 increment analysis for NCIR did not include <u>all</u> increment-consuming emissions and thus any evaluation of the extent of existing increment violations is incomplete. For example, Basin Electric failed to include SO_2 emissions from the Yellowstone Energy Limited Partnership (YELP) facility which has increased SO_2 emissions by 1,932 tons per year since 1977 according to the Final Environmental Impact Statement for the Roundup Power Project.[116] Further, Basin Electric failed to include any of the SO_2 increment consuming sources from North Dakota, or the increment consuming emissions from Billings, Montana sources. In addition, Basin Electric only modeled the 90th percentile maximum 3-hour and 24-hour average SO_2 emission rates from Colstrip Units 3 and 4, rather than the maximum 3-hour and 24-hour average emission rates from these units which is required by the NSR Workshop Manual (at C.49). Thus, Basin Electric must be required to revise its SO_2 increment analyses for the NCIR Class I area to include all increment consuming emissions and sources, as mandated by EPA policy and regulation.

In any case, there is sufficient documentation at this point to mandate that WYDEQ deny the proposed permit for Dry Fork due to Dry Fork's contribution to the existing SO_2 increment

[115] See April 12, 2002 letter from EPA, Region VIII to the North Dakota Department of Health, Attachment 23.
[116] Final EIS for Roundup Power Project is available on the Montana Department of Environmental Quality's internet site at www.deq.state.mt.us/eis/Roundup_EIS/RndupPwrPrjCmpltFEIS.pdf.

violations at NCIR pursuant to WAQSR Chapter 6, Section 4(b)(i)(A)(I) and Chapter 6, Section 2(c)(viii)(ii).

12. THE CLEAN AIR ACT REQUIRES A COMPLETE ANALYSIS OF THE IMPACT OF THE PROPOSED PROJECT ON SOILS AND VEGETATION

The CAA's PSD requirements include a *specific obligation* for permitting authorities and permit applicants to evaluate soils and vegetation (in addition to ambient air quality) in any area that will be affected by any aspect of the proposed project (including construction):

> [T]he analysis required under this subsection . . . shall require an analysis of the ambient air quality, climate and meteorology, terrain, *soils and vegetation*, and visibility at the site of the proposed major emitting facility and in the area potentially affected by the emissions from such facility for each pollutant regulated under this chapter which will be emitted, or which results from the construction or operation of, such facility.

CAA § 165(e)(3)(B).

The obligation to consider impacts on soil and vegetation is a long-standing requirement of the PSD program, and includes an obligation to perform a site-specific inventory of soils and vegetation *before* the issuance of a draft permit and prior to the date of any public hearing. Such analysis must consider the variety of soils and vegetation in the area, the possibility of adverse impacts on soils and vegetation for PSD-regulated pollutants (including the possibility of adverse impacts at ambient concentrations that are lower than the applicable NAAQS, the impact of PSD pollutants – like fluoride – for which there is no NAAQS, and impacts from concentrations of pollutants that are lower than generalized screening levels),[117] the possibility of adverse impact from non-PSD regulated pollutants, and the potential for any other site-specific environmental effects. *See In re Indeck-Elwood*, PSD Appeal 03-04, slip op at 31-52 (EAB Sept. 27, 2006).[118]

As a result, permitting authorities (including WYDEQ) are obligated to perform (or require of applicants) an analysis that *specifically inventories the various soils and plant life* (including but not limited to threatened or endangered species) in the vicinity of the proposed facility and in any other area affected by the construction or operation of the proposed facility. The analysis must then determine whether such soils or vegetation will be adversely affected by any of the plant's emissions (during construction or operation). At least, such analysis must include the full range of PSD pollutants (including fluoride), as well as any relevant non-PSD pollutants (including sulfuric acid mist, mercury, beryllium, etc.).[119]

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[117] In particular, permitting authorities cannot blindly rely on the 1980 *Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals* ("1980 Screening Levels). For example, EPA's NSR Manual specifically recognizes that "there are sensitive species which may be harmed by long term exposure to low concentrations of pollutants for which there are no NAAQS" and that under certain circumstances soil and vegetation analysis "has to go beyond a simple screening." *See In re Indeck-Elwood*, PSD Appeal 03-04, slip op at 38 (EAB Sept. 27, 2006).

[118] It is worth noting that the requirement to evaluate impacts on soil and vegetation apply not only to the coal-fired steam boilers but to all sources at the proposed plant, individually and in the aggregate.

[119] Among other things, acidic pollutants (or precursors), such as SO2, NOx, and hydrogen chloride can directly affect soil chemistry and have significant impacts on important habitat, vegetation, and potentially animal life

Significantly, the soil/vegetation analysis must be completed *before a draft permit can appropriately issue,* among other things to allow the public and others a meaningful opportunity to comment on the analysis and any possible or likely impacts.

The EAB has made clear that in conducting this analysis reference simply to the primary and secondary NAAQS and PSD increments as evidence that proposed major source will not harm soils or vegetation would essentially write the soils and vegetation analysis out of the Act – making it an unnecessary redundancy. This reading is contrary to fundamental principles of statutory interpretation; rather, permitting authorities must require or conduct an actual, site-specific analysis of potential impacts on soil and vegetation. Permitting authorities may not substitute a discussion of compliance with NAAQS and PSD increments for an actual evaluation based on an inventory and assessment of the impacts to soils and plant life in the area of a proposed major source.[120]

Secondly, permit applicants and permitting authorities may not blindly rely on the EPA's 1980 Screening Levels. The EAB has recognized that:

> there is ample indication in the Screening Procedure itself that, in keeping with a concept of a "screening" tool, the analysis provided in the Screening Procedure may in some cases be incomplete and preliminary. In its overview section, for example, the 1980 Screening Procedure states as follows:
>
>> In keeping with the screening approach, the procedure provides conservative, *not definitive results*. * * * The estimation of potential impacts on plants, animals, and soils is extremely difficult. The screening concentrations provided here are not necessarily safe levels nor are they levels above which concentrations will necessarily cause harm in a particular situation. However, *a source which passes through the screen without being flagged for detailed analysis cannot necessarily be considered safe.*[121]
>
> Additionally, there are indications that the Screening Procedure does not purport to be complete in its coverage. The guidance observes in this regard, "[i]deally, the screening procedure should address the impacts of *all the pollutants* currently regulated under the [CAA], but as shown in Table 2.1, screening concentrations were found for *only half* of the regulated pollutants." Id. at 4. In fact, the guidance can only be used to screen for potential effects caused by concentrations of the pollutants in the ambient air *for only seven pollutants* because, at the time the guidance was developed, there were only sufficient data for those seven pollutants. Id. at 5; see also id. at 11, tbl. 3.1 (listing vegetation sensitivity levels for seven pollutants: sulfur dioxide, ozone, nitrogen oxide,

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(especially aquatic life). The applicants must examine the full range of these possible effects in connection with this PSD permit application.

[120] Nor can a permitting authority (or the permit applicant) rely on vague generalizations, such as assertions that emission of a particular kind are "trivial," without evaluating what those emissions will be and why they are expected to have no adverse impacts. *See Indeck-Elwood,* slip op at 40.

[121] Citing 1980 Screening Procedure at 2-3 (emphasis added).

> carbon monoxide, sulfuric acid, ethylene, and fluorine). Also, the guidance notes that there was a *lack of data on chronic effects* when it was developed. In short, the 1980 Screening Procedure does not purport to address a number of pollutants with respect to which concerns have been raised here, including sulfuric acid mist, volatile organic materials (VOM), hydrogen chloride, and beryllium, and it does not consider the kinds of chronic effects that may be germane to a protected area like the Midewin.

Indeck-Elwood, slip op at 43-45.

The EAB observed as well that the data upon which the screen limits are based are *more than 26 years old* and did not even rely on native species for their analysis. *Id* at 45. In sum, the statutory requirement for a thorough evaluation of soils and vegetation is not satisfied by mere assertion or by the application of a screening tool or other analysis that is incomplete.

The 1990 NSR Manual, which reflects the Agency's more recent thinking about how to evaluate impacts on soil and vegetation, states that such analysis "should be based on an inventory of the soils and vegetation types found in the impact area," and an applicant must "determine the sensitivities of the plant species listed in the inventory to the applicable pollutants that would be emitted from the facility and compare this information to the estimates of pollutant concentrations calculated in the air quality modeling analysis (conducted pursuant to 40 C.F.R. § 52.21(m)) in order to determine whether there are any local plant species that may potentially be sensitive to the facility's projected emissions. . . . For those plants that show potential sensitivity, a more careful examination would be conducted. . . . *Plainly, the NSR Manual contemplates the development of site-specific information that goes beyond the scope of simple screening under the 1980 Screening Procedure.*" *Indeck-Elwood*, slip op at 46 (citing and quoting the NSR Manual). As the EAB has explained, the soils and vegetation component of the PSD requirements "contemplates a *comparative analysis* of some kind between the existing baseline conditions of soils and vegetation at the site and in the potentially affected area, and the effects of the emissions on such baseline conditions" that "shall be available *at the time of the public hearing on the application for such permit.*" *Indeck-Elwood*, slip op at 42-43.

The draft permit is defective because there was an inadequate analysis of the effect of emission of pollutants on soils and vegetation. For example, the methodology used in the permit application was a simple screening of research papers. There was no *site specific inventory* of soils or vegetation performed as part of the permit application. Therefore, it is impossible to know whether any endangered, threatened, or sensitive species are located in or around the plant site. Further, the permit application screening methodology was limited to the criteria pollutants of SOx and NOx. There permit application failed to analyze the potential impacts of emissions of the following pollutants: fluorine, sulfuric acid, mercury, beryllium, ozone, hydrogen chloride, carbon monoxide, and ethylene. Moreover, the permit application did not appear to analyze emissions from all sources—and instead it appears that the analysis was limited to emissions from the stack.

This abdication of a critical substantive obligation demonstrates that WYDEQ has not taken seriously its solemn responsibility to fully evaluate the impact of this new major source. In so doing WYDEQ has denied the public its ability to meaningfully comment on its decision making process, and contribute constructively to the permit determination. As a result, WYDEQ must withdraw the draft permit, prepare an appropriate soils and vegetation analysis, and provide an adequate opportunity for public comment (including public hearing) as the PSD provisions require.

Thank you for considering our comments. Please include all of the groups signed below on the mailing lists for any future actions by WYDEQ regarding Basin Electric's application to construct the Dry Fork power plant.

Sincerely,

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Attachments

List of Attachments to Comments Submitted on WYDEQ's Proposed Permit for Dry Fork Power Plant

Attachment No.	Name of Document	
1	**EPA NSR Workshop Manual, p. b.49.**	
2	*Considering Alternatives: The Case for Limiting CO_2 Emissions from New Power Plants through New Source Review* by Gregory B. Foote	
3	Letter from Illinois Division of Air Pollution Control to Jim Schneider, Indeck-Elwood, LLC (March 8, 2003)	
4	Letter from Illinois EPA Director to EPA Regional Administrator, Region V (March 19, 2003)	
5	Letter from James A. Capp, Manager, Stationary Source Permitting Program, Georgia DNR, to D. Blake Wheatley, Assistant Vice President, Longleaf Energy Associates, LLC (March 6, 2002).	
6	Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Corporation (Dec. 23, 2002).	
7	Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Company (Aug. 29, 2003).	
8	Montana Board of Environmental Review, Findings of Fact, Conclusions of Law, and Order In the Matter of the Air Quality Permit for the Roundup Power Project (Permit No, 3182-00), Case No. 2003-04 AQ (June 23, 2003).	
9	April 6, 2004 letter from Richard R. Long, EPA, to Rick Sprott, Utah Division of Air Quality.	
10	"The Cost of Mercury Removal in an IGCC Plant," US DOE, NETL, September 2002.	
11	November 27, 2007 Draft Permit to be issued to Christian County Generation for an IGCC Plant Near Taylorville, Illinois	
12	Major Environmental Aspects of Gasification-Based Power	

	Generation Technologies, US DOE, December 2002.	
13	EPA's Final Report entitled "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies," at ES-7.	
14	Tom Bartolomei, ALSTOM, *Sliding Pressure Supercritical Boilers: Flexible and Efficient Technology for New Coal-Fired Generation*, presented at COAL-GEN, August 1, 2002.	
15	November 24, 1986 EPA memo with subject "Need for Short-term Best Available Control Technology (BACT) Analysis for the Proposed William A. Zimmer Power Plant."	
16	Bryk, S.A. et al., First Commercial Application of DRB-4Z™ Ultra-Low NOx Coal-Fired Burner, presented to POWER-GEN International 2000, November 14-16, 2000, Orlando, FL.	
17	Whitfield, T. et al., Comparison of NOx Emission Reductions with PRB and Bituminous Coals in 900 MW Tangentially-Fired Boilers, presented to EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollutant Control Mega Symposium, May 19-22, 2003, Washington, D.C.	
18	Penterson, Craig A., Reducing NOx Emissions to Below 0.15 lb/10^6 Btu on a 600 MW Utility Boiler with Combustion Control Only, presented to EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollutant Control Mega Symposium, May 19-22, 2003, Washington, D.C.	
19	Bielawski, G.T., J.B. Rogan, and D.K. McDonald, How Low Can We Go? Controlling Emissions in New Coal-Fired Power Plants, Presented to the U.S. EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Symposium: "The Mega Symposium," August 2001.	
20	May 5, 2005 Newmont Nevada Energy Investment Class I Air Quality Operating Permit to Construct.	

21	2000 Directory of Power Plants Burning Wyoming Coal which was obtained from the Wyoming Geological Survey.	
22	Appendix C of the Gascoyne Permit Application.	
23	April 12, 2002 letter from EPA, Region VIII to the North Dakota Department of Health.	
24	December 8, 2005 Air Quality Permit for the Roundup Power Project.	
25	May 16, 2005 Air Quality Permit for the Hardin Generation Project.	
26	June 17, 2003 MACT permit and associated Technical Support Document for MidAmerican Energies' Unit 4 at the Council Bluffs Energy Center.	
27	Nevada Department of Environmental Protection's proposed permit to be issued to White Pine Energy Associates, LLC.	
28	Bustard, Jean *et al.*, Full-Scale Evaluation of Mercury Control Technologies with PRB Coals, presented at ICAC's Clean Air Technologies & Strategies Conference & Workshop, Baltimore, MD, March 7-10, 2005.	
29	McCoy, Melanie *et al.*, "Full-Scale Mercury Sorbent Injection Testing at DTE Energy's St. Clair Station," presented at the Combined Power Plant Air Pollutant Control Mega Symposium, Washington, D.C., August 30 – September 2, 2004.	
30	October 15, 2004 Approval Order for Unit 3 at Intermountain Power Generating Station.	
31	Air Pollution Control Permit to Construct for the Gascoyne Generating Station.	
32	March 2, 2004 Permit to Construct for Longview Power.	
33	EPA's March 31, 1994 letter to the Iowa Department of Natural Resources	