RESPONSES OF THE BASIN ELECTRIC POWER COOPERATIVE TO EPA, NPS AND ENVIRONMENTAL GROUP COMMENTS REGARDING THE WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY'S PERMIT APPLICATION ANALYSIS FOR THE DRY FORK STATION

This document provides responses to the EPA, National Park Service (NPS) and the combined environmental group (Powder River Basin Resource Council, Wyoming Chapter of Sierra Club, Wyoming Wilderness Association, Wyoming Outdoor Council, Biodiversity Conservation Alliance, Western Resource Advocates, and Natural Resources Defense Council (collectively ENV)) comments on the Wyoming Department of Environmental Quality's (WDEQ) Permit Application Analysis to the Draft Prevention of Significant Deterioration (PSD) Permit to Construct for Basin Electric Power Cooperative's (Basin or Basin Electric) new Dry Fork Station.

Each comment is reiterated below (though the text of the comment may have been summarized), and similar comments have been combined for response purposes. A response is then provided and the response is in italics. The comments are grouped into those from EPA, those from NPS, and finally those from the environmental groups (ENV).

EPA Comment #1 (ENV #7.d)

a. Permit fails to set BACT limit for sulfuric acid mist.

Response: *Basin provided a BACT analysis for the control of sulfuric acid mist (H_2SO_4) emissions from the proposed Dry Fork Boiler. See Exhibit 1 (Response to WDEQ's Completeness Review Dated March 28, 2006 (June 14, 2006) ("June 2006 Response") at Attachment 1). The BACT analysis included an evaluation of control technologies available to reduce H_2SO_4 emissions from the main boiler (including both wet and dry flue gas desulfurization (FGD) systems). The BACT analysis concluded that the combination of dry FGD and the fabric filter baghouse (DFGD+FF) provided the most effective H_2SO_4 control. Basin proposed a controlled H_2SO_4 emission rate of 0.0045 lb/MMBtu based on anticipated H_2SO_4 control efficiencies and the ability to demonstrate compliance with the BACT emission limit.*

Additional analysis was done by Sargent & Lundy, reported in Memorandum dated June 8, 2007 regarding Proposed H_2SO_4 Emission Limits, Exhibit 2. The following draws on that analysis.

<u>*Sulfuric Acid Mist Emission Calculations*</u>

Sulfuric acid mist emissions were calculated based on: (1) the sulfur content of the fuel; (2) 2% SO_2 to SO_3 oxidation across the boiler and SCR; (3) 100% conversion of flue gas SO_3 to H_2SO_4; and (4) an H_2SO_4 removal efficiency for each potentially feasible control technology. Potential uncontrolled H_2SO_4 emissions from the Dry Fork boiler were calculated as follows:

$$\frac{1.21\ \text{lb}\ SO_2}{\text{MMBtu}} \cdot \frac{\text{lbmole}\ SO_2}{64\ \text{lb}\ SO_2} \cdot 2\% \cdot \frac{98\ \text{lb}\ H_2SO_4}{\text{lbmole}\ H_2SO_4} = 0.037\ \text{lb}\ H_2SO_4/\text{MMBtu}$$

Control Technology Discussion

A summary of the control technology evaluation included in the Dry Fork permit application and the revised H_2SO_4 BACT analysis is provided below.

Dry FGD/Fabric Filters

As discussed in the permit application, dry FGD control systems, including spray dryer absorbers (SDA) and circulating dry scrubbers (CDS), are technically feasible SO_2/SO_3 control options. Dry FGD systems are designed to use a lime and water slurry injected into the absorber tower to remove SO_2 from the combustion gases. SO_3 will also react with the reactant sprayed into the absorber tower to form calcium sulfate. Dry FGD systems are located upstream of the system's particulate control device and tend to increase the alkalinity of the filter cake, enhancing SO_3 removal in the fabric filter.

A portion of the SO_3 generated in the boiler and SCR will be captured in the unit's fabric filter (BACT for PM_{10} control). Fly ash cake that accumulates on the filter bags acts as an alkaline filter through which the flue gas must pass. SO_3, which is very reactive, readily reacts with alkaline components of the fly ash at temperatures below the H_2SO_4 dewpoint to form sulfate salts. The SO_3 removal efficiency of a fabric filter is dependent upon the alkalinity of the fly ash cake. Fabric filters associated with highly alkaline fly ash will significantly reduce the SO_3 concentration in the flue gas. Coals containing the highest alkalinity are generally low-rank coals such as the subbituminous coals from the Power River Basin and lignites. Singer, J.G., editor, Combustion Fossil Power, Combustion Engineering, Inc., 4th ed., 1991 (pp 9-14). A dry FGD control system located upstream of the fabric filter will also increase the alkalinity of the filter cake.

The combination of dry scrubbing and fabric filtration has demonstrated the ability to achieve a high SO_3 removal efficiencies from conventional pulverized coal-fired combustion flue gas streams. Based on engineering judgment, it is estimated that a dry scrubber designed as an SDA or CDS, used in conjunction with a fabric filter baghouse, would reduce potential H_2SO_4 emissions by at least 88% under normal operating conditions. A control efficiency of 88% results in an average H_2SO_4 concentration in the flue gas of approximately 1.8 ppmvd @ 3% O_2, which is equivalent to an emission rate of approximately 0.0045 lb/MMBtu.

Wet FGD

Wet FGD was also evaluated as a potential post-combustion SO_2/SO_3 control technology. As discussed in the permit application, the wet scrubbing process uses an alkaline slurry made by adding lime or limestone to water. The alkaline slurry is sprayed into the absorber tower and reacts with SO_2 in the flue gas to form insoluble calcium sulfite and calcium sulfate solids. A wet FGD system must be located downstream of the unit's particulate control device.

SO_3 entering the wet scrubber will react with water and create micron sized sulfuric acid droplets. Micron sized droplets can pass through the spray levels in the absorber tower and the mist eliminator and be emitted as sulfuric acid mist. Although some of the sulfuric acid droplets will react with the alkaline reactant in the wet scrubber, industry experience suggests that many of the micron-sized droplets will not come into contact with limestone. Gooch, J.P., Dismukes,

E.B., Formation of Sulfate Aerosol in an SO_2 Scrubbing System, Southern Research Institute, Birmingham, AL. Because of the inherently low SO_3 concentration in the flue gas associated with firing sub-bituminous coal, it is anticipated that a wet FGD system would reduce potential H_2SO_4 emissions by approximately 40% to 60%.

Because the overall control efficiency of a wet FGD system will be lower than the control efficiency of the DFGD/FF control scenario, and because the wet FGD system will result in significant collateral environmental issues, wet scrubbing was not considered a technically viable H_2SO_4 control system for the Dry Fork main boiler.

Wet electrostatic precipitation (WESP) has been proposed on other coal-fired projects as one technology to reduce sulfuric acid emissions from utilities firing high-sulfur eastern bituminous coals controlled with wet FGD. See, e.g., Thoroughbred Generating Station PSD Permit Application, Submitted to Kentucky Department of Environmental Protection, October 26, 2001. WESP has been demonstrated as an effective control technology to abate SO_3 mist from industrial applications with relatively low flue gas flow rates and high acid mist concentrations, such as sulfuric acid plants. However, until recently, the technology has not been applied to the utility industry because of the high gas flow volumes and low acid mist concentrations associated with utility flue gas. In a utility application, the WESP would be located downstream from the wet FGD to remove micron-sized H_2SO_4 aerosol from the flue gas stream as a condensable particulate.

There is limited commercial operating experience upon which to base a conclusion regarding the effectiveness of WESP on a large utility boiler, and no experience with WESP on a subbituminous fired boiler equipped with dry FGD and fabric filter. In general, WESP systems have been designed to achieve controlled H_2SO_4 emission rates in the range of 5-10 ppmvd. The low sulfur subbituminous fuel proposed for the Dry Fork boiler will generate a maximum H_2SO_4 concentration in the boiler flue gas of approximately 15 ppmvd (uncontrolled), a concentration essentially equivalent to the H_2SO_4 emission rates achieved in practice with WESP in high-sulfur applications. The proposed DFGD/FF control systems are expected to reduce the average H_2SO_4 emission rate to less than 1.8 ppmvd @ 3% O_2. There is no operating history or data available demonstrating that a WESP would be effective on a unit firing subbituminous coal and equipped with DFGD+FF. Because the feasibility and effectiveness of WESP has not been demonstrated on subbituminous-fired boilers, WESP was not considered technically feasible or commercially available for the Dry Fork boiler configuration.

<u>Proposed BACT Emission Limit and Compliance Demonstration</u>

Basin's BACT concluded that the combination of dry FGD and the fabric filter baghouse provided the most effective H_2SO_4 control. Basin proposed a controlled H_2SO_4 emission rate of 0.0045 lb/MMBtu. An emission rate of 0.0045 lb/MMBtu is equivalent to an H_2SO_4 concentration in the flue gas of approximately 1.8 ppmvd @ 3% O_2. Assuming an uncontrolled H_2SO_4 emission rate of 0.037 lb/MMBtu (calculated based on 2% SO_2 to SO_3 conversion in the boiler and SCR), the combination of emission control technologies will have to achieve a removal efficiency of at least 88% to ensure compliance with the proposed emission limit.

Compliance Demonstration – Test Method Limits

As discussed in the permit application, the test method used to measure H_2SO_4 emission rates (EPA Test Method 8) has proven to be problematic on coal-fired boilers. For example, interfering agents with Method 8 include fluorides and free ammonia (ammonia). In fact, Method 8 states that if "any of these interfering agents is present... alternative methods, subject to the approval of the Administrator, are required." One alternative test method that has been proposed to measure sulfuric acid emissions from stationary sources is the controlled condensation method (Method 8A), however, certain flue gas characteristics may also result in measurement biases with this method. See, Blythe, G., et al. "Improvements to the Controlled Condensation measurement method for Sulfuric Acid," presented at the EPRI-DOE-EPA Combined Utility Air Pollution Control Symposium: The Mega Symposium. Atlanta, GA, August 16–20, 1999. See also, Blythe, G., et al. "Flue Gas sulfuric Acid Measurement Method Improvements."

Because of the difficulties associated with measuring very low H_2SO_4 emission rates, equipment vendors have not been willing to guarantee H_2SO_4 emissions below approximately 2 ppmvd @ 3% O_2. Based on information from equipment vendors, an emission rate in the range of 1 to 2 ppmvd @ 3% O_2, represents the practical analytical detection limit of Methods 8 and 8A on a coal-fired boiler.

At the 2007 Electric Power Conference (Rosemont, Illinois May 1–3, 2007), Mr. Scott Evans of Clean Air Engineering presented a paper discussing the feasibility of using Method 8 to demonstrate compliance with low H_2SO_4 emission limits. Clean Air Engineering provides, among other services, stack testing services for utility boilers. See, http://www.cleanair.com. Mr. Evan's presentation, "Demonstrating Compliance with Sub-ppm Acid Mist Limits: Can Method 8 Handle the Challenge" summarized data from an evaluation of the Method 8 biases and detection limits. Among other findings, the study included the following conclusions:

- *Practical Limit of Quantitation (PQL) is about 0.5 ppm under tightly controlled conditions;*
- *PQL is likely higher in the field [range of 1-2 ppm];*
- *Many positive bias effects – some correctable;*
- *Longer runs do not improve detection limits;*
- *Analysis at sub-ppm levels are very sensitive, i.e., small analytical errors lead to large positive biases; and*
- *All bets are off if ammonia is present in the flue gas.*

These conclusions are consistent with information submitted in the permit application and information obtained from emission control equipment vendors, that is, that the practical analytical detection limit of Method 8 on a coal-fired boiler is in the range of approximately 1 to 2 ppm.

Other Recently Permitted/Proposed H_2SO_4 Emission Limits

Basin's BACT analysis included a list of other recently issued/proposed H_2SO_4 BACT limits for coal-fired boilers. A majority of the recently issued BACT limits were between 0.0037 and 0.0050 lb/MMBtu. The lowest H_2SO_4 emission limits identified in the RBLC Database were:

- *City Utilities of Springfield - Southwest Power Station (Missouri)*
  - *Fuel: subbituminous coal*
  - *Control Technology: dry FGD*
  - *Emission Limit: 0.000184 lb/MMBtu*
- *Newmont Power Station (Nevada)*
  - *Fuel: subbituminous coal*
  - *Control Technology: dry FGD*
  - *Emission Limit: 2.06 lb/hr (0.001 lb/MMBtu)*

An emission rate of 0.000184 lb/MMBtu is equivalent to an H_2SO_4 concentration in the flue gas of approximately 0.07 ppmvd @ 3% O_2. Based on information summarized above, this emission rate is significantly below the PQL of Method 8. An emission rate of 0.001 lb/MMBtu is equivalent to an H_2SO_4 concentration in the flue gas of approximately 0.4 ppmvd @ 3% O_2, which is equal to, or slightly below, the PQL of Method 8 under tightly controlled conditions. Based on information from equipment vendors and stack testing companies, both of these facilities will have significant challenges demonstrating compliance with the respective permit limits because of the limitations in the test method.

Conclusions

Based on the review of potentially available emission control technologies, Basin is confident that the proposed control systems (DFGD + FF) will provide the most effective H_2SO_4 control, and that the control systems will consistently achieve H_2SO_4 removal efficiencies of at least 88% and controlled H_2SO_4 emissions below approximately 1.5 ppm @ 3% O_2. However, as discussed in the BACT analysis, Basin is concerned about the ability of the reference test method to accurately measure H_2SO_4 concentrations in boiler flue gas at low ppm levels, and Basin is not required to propose a permit limit that is at, or below, the PQL of the test method. See In re Newmont Nevada Energy Investment, L.L.C., TS Power Plant ("Newmont EAB Decision"), EAB PSD Appeal No. 05-04 (Dec. 21, 2005), slip op. at 15 ("[A] permit issuer may appropriately consider, as part of its BACT analysis, the extent to which available data in the record evidence the ability to consistently achieve certain emissions rates or control effectiveness of the selected technology or pollution control method."); at 16 (BACT analysis must be grounded on what is known about the select technology's effectiveness); at 17 (emission limits must reflect consideration of any practical difficulties associated with using the control technology). Therefore, it is Basin's position that a controlled emission rate of 0.0045 lb/MMBtu (approximately 1.8 ppmvd @ 3% O_2) represents BACT for H_2SO_4 control for the following reasons:

- *The proposed emission rate will require significant H_2SO_4 control in the DFGD and FF.*
- *Compliance with the emission rate can be demonstrated using EPA Test Method 8A.*

- *On-going compliance with the H_2SO_4 BACT limit will be based on demonstrating compliance with the SO_2 and filterable PM_{10} BACT limits. Basin's stringent SO_2 and filterable PM_{10} BACT limits will require proper operation of the DFGD and FF control systems.*
- *Air quality impact modeling conducted at the proposed H_2SO_4 emission rate demonstrated that emissions from the proposed unit will not contribute to any violations of the applicable NAAQS standards and PSD increments, or cause any adverse impacts on Class I Areas.*

b. Permit fails to set BACT limit for fluoride.

Response: *Basin performed a BACT analysis for fluoride. See Dry Fork Station PSD Permit Application (November 2005) ("Permit Application"), at Section 5.2.7. Basin's BACT analysis concluded that an emission limit of 2.62 lb/hr was BACT for HF. Basin expects that the final permit will contain a HF permit limit of 2.62 lb/hr using a dry scrubber followed by a fabric filter, based on the BACT analysis.*

c. Permit fails to set BACT limit for VOCs.

Response: *Basin performed a BACT analysis for VOCs. Permit Application at Sec. 5.2.5. Based on this analysis Basin concluded that good combustion controls with an emission limit of 0.0037 lb/MMBtu represents BACT for VOC. Id. WDEQ concurred with this conclusion. WDEQ, Division of Air Quality, Permit Application Analysis, NSR-AP-3546 (February 5, 2007), at 14 ("Permit Application Analysis"). Basin proposes that the final permit contain a VOC permit limit of 0.0037 lb/MMBtu using good combustion controls based on the BACT analysis.*

EPA Comment #2 (ENV #7(d))

The draft permit does not contain a BACT emission limit for ammonia. EPA recommends that Wyoming examine whether or not a BACT limit for ammonia should be included in the permit.

Response: *While an ammonia limit has not been included in other recently issued Wyoming permits for coal-fired power plants (e.g., Wygen, Two Elks), Basin agrees to a permit limit of 10 ppm ammonia, based on a 3-hr test using EPA Conditional Test Method 27.*

EPA Comment #3

The hours of operation for auxiliary boiler and inlet gas heater should be limited to 2000 hours and reflected as enforceable conditions in the permit, not just as footnotes describing the basis for the calculation. This would be consistent with the WDEQ's Permit Application Analysis. (EPA #3).

Response: *Basin agrees to a permit condition limiting the hours of operation for the auxiliary boiler and inlet gas heater to 2000 hours per year, with a requirement to keep a record of operating hours.*

EPA Comment #4

Need to establish BACT limits for SO_2 and NO_x in lb/MMBtu on a rolling 30-day or shorter average to demonstrate that BACT will not result in emissions above NSPS. A lbs/hr limit cannot be equated to a lbs/MW-hr (especially at low boiler loads), while a lbs/MMBtu limit can be. But a 12-month rolling average lbs/MMBtu emission limit cannot be compared to a 30-day average lbs/MW-hr.

Response: *While Basin believes that there are no practical operating scenarios within which it could meet the SO_2 and NO_x 30-day lbs/hr limits in its permit and exceed the NSPS limits (this result would require the facility to operate at less than 50% load for a 30-day operating period), to address EPA's concern that BACT limits for SO_2 and NO_x in lb/MMBtu on a rolling 30-day or shorter average are needed to demonstrate that BACT will not result in emissions above NSPS, Basin proposes an additional NO_x permit limit of 0.07 lb/MMBtu on a 30-day average (while retaining the lower annual average limit of 0.05 lb/MMBtu). Basin similarly is willing to accept an additional SO_2 permit limit, at a level to be determined, on a 30-day average (while retaining the annual average limit of 0.08 lb/MMBtu). 30-day average BACT analyses for NO_x and SO_2 at Dry Fork, are discussed further in Exhibit 3 (Response to WDEQ's Completeness Review dated December 21, 2005 (March 3, 2006) ("March 2006 Response") at Attachment No. 1 (SO_2), and Attachment No. 2 (NO_x)), and in Exhibit 4 (Response to WDEQ's Completeness Review dated May 30, 2006 (July 14,2006) ("July 14, 2006 Response") at 1-2 (NO_x) and 3-5 (SO_2)). Consistent with EPA's comment, the 30-day lbs/MMBtu emission rates for NO_x and SO_2 can be equated to a lbs/MW-hr limit, and are easily confirmed to be at least as stringent as the NSPS. At the same time, by maintaining lower annual averages for NO_x and SO_2, the Dry Fork Station will achieve the overall emissions reductions intended by WDEQ in setting the low annual averages.*

EPA Comment #5

Averaging Period for SO_2. BACT requires a short term averaging period; an annual average does not meet this requirement. No other permits have used an annual average. EPA 1987 and 1989 guidance supports requirement to use short-term averages.

Response: *The draft permit contains an aggressive SO_2 annual average limit of 0.08 lb/MMBtu, a 30-day average limit of 304.1 lb/hr, and a 3-hour average limit of 380.1 lb/hr. Thus, the Basin permit does contain short term permit limits for SO_2. Contrary to EPA's comments, the 1989 guidance does not require use of 30-day or shorter averaging periods for emission limits. EPA recognizes that "in some situations, it is not reasonable to hold a source to a one month limit. In these cases, a limit spanning a longer time is appropriate if it is a rolling limit. However, the limit should not exceed an annual limit rolled on a monthly basis." EPA, "Guidance on Limiting Potential to Emit in New Source Permitting" at 9 (June 13, 1989). Moreover, the Environmental Appeals Board (EAB) recently noted that the "U.S. EPA has stated a preference for shorter term, rather than longer term, averaging periods for permit limits. However, this preference does not demonstrate that longer averaging times are clearly erroneous . . . ." <u>In re Prairie State Generating Co</u>. ("Prairie State EAB Decision"), EAB PSD Appeal No. 05-05 (Aug. 24, 2006), slip op. at 80 (internal citations omitted). While Basin ~~believes that the current proposed SO_2 permit limits are adequate and an additional short term~~*

limit is not required, as stated in the response to EPA Comment #4 above, Basin is nonetheless willing to accept an additional 30-day average SO_2 BACT limit, at al level to be determined, in addition to the current proposed SO_2 limits in the draft permit.

EPA Comment #6

Averaging Period for NO_x. Need to establish BACT limits for NO_x in lb/MMBtu on a rolling 30-day or shorter average. A 12-month averaging time does not "go much further" than a 30-day averaging time in minimizing the effect of emission spikes for NO_x. For the same reasons as with SO_2, a 12-month rolling average is too lengthy an averaging time to represent BACT.

Response: *The draft permit contains a stringent limit of 0.05 lb/MMBtu annual average for NOx, as well as a 30-day average limit of 190.1 lb/hr. As discussed in the responses to EPA Comments #4 and #5 above, an additional short term limit in lb/MMBtu is not required for BACT. However, as discussed in response to EPA Comment # 4 above, Basin is nonetheless willing to meet a BACT limit of 0.07 lb/MMBtu 30-day average for NO_x emissions, in addition to the current proposed NO_x limits in the draft permit.*

EPA Comment #7

Averaging periods should be consistently listed in tables in Condition 9 (PM and CO limits do not include averaging periods).

Response: *Basin agrees that averaging periods should be consistently listed in the tables in Condition 9. Permit Application Analysis at 47. Specifically, the lb/MMBtu and the lb/hr emission rates for PM/PM_{10} are based on an average of three (3) one-hour stack tests. Permit Application at Section 6.1; March 2006 Response at Attachment 3 (Exhibit 3). The lb/MMBtu emission rate for CO is based on three (3) one-hour stack tests. Permit Application Analysis at 49.*

EPA Comment #8 (NPS p. 6)

WDEQ should require CEMS to monitor filterable particulate matter.

Response: *Neither the Clean Air Act nor Wyoming regulations require the use of continuous emission monitors for particulate matter. Other regulatory agencies have also found that PM CEMS are not advanced enough to provide reliable and accurate data at a reasonable cost. See Newmont EAB Decision at 66. The boiler will be equipped with a continuous opacity monitoring system (COMS), which can serve as an acceptable surrogate for particulate matter and Basin will be required to conduct annual PM/PM_{10} source tests. The use of COMs as a surrogate for PM_{10} compliance is consistent with the NSPS. 70 Fed. Reg. 7905, 7908 (Feb. 16, 2005). EPA explained that while COMS "cannot directly measure PM emissions," a "properly calibrated and maintained COMS is sufficient to demonstrate long-term PM control device performance, since the purpose of the monitoring is to demonstrate with reasonable certainty that the PM control device is operating as well as it did during the PM emissions test used to demonstrate compliance." Newmont EAB Decision at 66 (citing 70 Fed. Reg. at 7908).*

While EPA comments that Wyoming should require CEMS, EPA does not provide sufficient evidence to question WDEQ's conclusions regarding particulate monitoring. See Newmont EAB Decision at 67 (citing In re Steel Dynamics, Inc., 9 E.A.D. 165, 194 (EAB 2000) ("'[W]here an alternative control option has been evaluated and rejected, those favoring the option must show that the evidence 'for' the control option clearly outweighs the evidence 'against' its application.'" (quoting In re Inter-Power of N.Y., Inc., 5 E.A.D. 130, 144 (EAB 1994))). As stated in the Newmont EAB Decision, "[w]hile PM/PM_{10} CEMs may become standard technology in the future, at the moment there is no legal requirement that they be installed on new coal-fired boilers in the United States." Newmont EAB Decision at 67. Similarly, there is no legal requirement that PM CEMs be installed at Dry Fork, instead, COMs will be used as a surrogate to ensure compliance with the PM filterable emission limit at Dry Fork.

EPA Comment #9

WY should require CEMS to monitor carbon monoxide emissions.

Response: *As stated in its permit application, Basin plans to install CO CEMs. Permit Application at Section 6.3.*

EPA Comment #10

WDEQ has chosen to include NSPS limits and citations, which PSD does not require, in this proposed permit. To avoid confusion and double standards, a permit condition should be added that states that PSD requirements (BACT limits) are separate from NSPS requirements, and the PSD requirements must be met regardless of compliance with the NSPS.

Response: *Basin will agree with clarifying language and plans to comply with both NSPS and PSD requirements.*

EPA Comment #11

Condition 12(A), (C), and (D) for NO, SO_2, and PM/PM_{10} include citations of the NSPS which contain exempt periods when determining compliance. PSD does not afford these exemptions, and it should be made clear in the permit that this is the case.

Response: *Condition 12 merely refers to initial compliance tests as required by the NSPS. Condition 14 (A), and (B) provides for CEMs data to demonstrate ongoing compliance with the NO_x and SO2 emission limits, and 14(D) provides for COMs to demonstrate ongoing compliance with the PM10 limits. Condition 15 provides further guidance on compliance with these limits. Because the Permit Application Analysis is not unclear in this regard there is no need for clarifying information.*

EPA Comment #12

Condition 7 requires performance testing, "within 30 days of achieving maximum design rate but not later than 90 days following initial start-up in accordance with Chapter 6, Section 20 of the Wyoming Air Quality Standards and Regulations (WAQS&R). If maximum design production rate is not achieved within 90 days of startup, the Administrator may require testing at the rate achieved and again when maximum rate is achieved." This permit language leaves it unclear whether performance testing is, in fact, required within 90 days after initial start-up. Further, the word "may" is ambiguous. We recommend the permit be reworded to say, "If maximum design production rate is not achieved within 90 days of start-up, the Administrator shall require testing at the rate achieved as of 90 days and again when maximum rate is achieved."

Response: *Basin believes that discretion should be left up to the Administrator. If there are problems with startup of the Dry Fork unit, it would make no sense to conduct a performance test when it is known that the unit is malfunctioning. Under those circumstances and others, it is appropriate to provide discretion to the Administrator to determine whether a source test should be conducted.*

EPA Comment #13

Conditions 13(B) & (E) require testing for fluoride and sulfuric acid mist. Both conditions require testing to be conducted through EPA test methods "or equivalent methods." We recommend that Conditions 13(B) and (E) be reworded to say "equivalent EPA approved test methods." We made a similar comment in our November 13, 2006 letter to you on the proposed PSD permit for Black Hills Corporation, WYGEN 3 facility.

Response: *The Wyoming State Implementation Plan (SIP) defines "equivalent method" as "any procedure, practice, policy, system or device which can be demonstrated to produce a result adequate for the purpose required in these regulations and consistent with specified reference methods." See 40 C.F.R. § 52.2620(c)(30)(i)(A); Wyoming Air Quality Standards and Regulations (WAQS&R), Chapter 1, Section 3. "Equivalent method" is not defined to include a requirement that a test method be approved by EPA. In fact, the Wyoming SIP provides that "the owner or operator of such source [new source] shall conduct a performance test(s) in accordance with methods and under operating conditions approved by the Administrator . . . ." See 40 C.F.R. § 52.2620(c)(30)(i)(A); WAQS&R, Chapter 6, Section 2(j). Both the Wyoming SIP and WDEQ Regulations provide that WDEQ (the Administrator) has discretion to approve alternate test methods. Thus, consistent with the Wyoming SIP and WDEQ Regulations, Basin believes that WDEQ should have discretion to approve alternate tests.*

EPA Comment #14(1)

WY should document how 557 lb/hr for CO emissions was calculated and whether it considered startup conditions.

Response: *As specified in the Permit Application Analysis the lb/hr emission limit for CO is 570.2. Permit Application Analysis at 47. The maximum CO emission rate during normal operation is based on the maximum heat input of 3,801 lb/MMBtu multiplied by the CO BACT rate of 0.015 lb/MMBtu. This equals 570 lb/hr, which is the CO emission limit established by the draft permit. Permit Application Analysis at 47.*

Startup conditions were considered in modeling for CO emissions. Additionally, the annual CO emission limit includes periods of startup, shutdown and malfunction. June 2006 Response at Attachment 2 (Exhibit 1).

EPA Comment #14(2)

WY should document how the 3-hour SO_2 limit of 380 lb/hr was calculated and whether it considered startup conditions.

Response: *To account for short-term variability in the controlled SO_2 emission rate, Basin proposed an average 3-hour SO_2 emission rate of 380.1 lb/hr. The 3-hour block average SO_2 limit includes startup emissions. This emission limit is based on a maximum heat input to the boiler of 3,801 MMBtu/hour and a controlled SO_2 emission rate of 0.10 lb/MMBtu. Establishing a mass-based short-term emission limit will allow Basin to respond to short-term excursions associated with fuel sulfur content, boiler load changes, and routine equipment maintenance and repairs. The 3-hour average emission rate of 380.1 lb/hr, based on 0.10 lb/MMBtu, is BACT for SO_2 as discussed in the July 14 Response, Exhibit 4; and Sargent & Lundy, Memorandum regarding SDA-CDS Comparison, June 8, 2007, Exhibit 5.*

NPS Comment #1 (p. 1-2)

WDEQ did not provide "all relevant information" to the Federal Land Manager (FLM) sufficiently in advance of the publications of the public notice. WDEQ should, therefore, extend the public comment period and conduct a public hearing.

Response: *As acknowledged by the NPS, the PSD rules require that FLMs should be provided notice and all information relevant to the permit application within 30 days of receipt of the application but no later than 60 days prior to public notice. WAQS&R Chap. 6, §2(n)(i). The required notice and all information regarding the permit application was provided in a timely fashion, as acknowledged by the NPS. NPS Comments at 1. There is no requirement in the rules that FLMs should receive an advance copy of a proposed permit or permit analysis prior to the public comment period, and the NPS cites no such requirement. Nonetheless, understanding the NPS' desire for additional time to consider the proposed permit and permit analysis, the WDEQ, in its public notice published on June 4, 2007, scheduled a public hearing and extended the comment period until that date. A copy of the public notice is attached as Exhibit 6.*

NPS Comment #2(1) (p. 3)

NPS states that a technological solution is now available that would allow the use of coal to generate electricity, without the emissions associated with PC boilers. NPS states that it has received applications for six proposed IGCC facilities and their relative emissions (in terms of lb/MWh_{net} for SO_2, NO_x, filterable PM10 and in lb/GWh_{net} for mercury) show IGCC is a cleaner coal-to-energy technology than that proposed by Basin Electric.

Response: *NPS states that IGCC is a clean coal technology that "should be considered" by Basin Electric. Though NPS does not request that IGCC be considered in the BACT analysis, it does provide a chart comparing proposed Dry Fork Station air permit limits with those for six* *proposed IGCC facilities. As discussed in response to ENV Comments #4 and 5, infra, none of the projects identified by commenters provide any operational data on emissions limits that have been achieved in practice. None of the projects identified by NPS has been constructed or operated yet.*

Not only is it the case that none of the identified projects is operating, there remains significant uncertainty whether several of them will ultimately be permitted and built. At a minimum, a number of these projects are likely to be delayed, further highlighting their inability to provide reliable operational experience.

- *<u>AEP—Mountaineer</u>: American Electric Power (AEP) recently announced that the cost estimate for its Mountaineer, West Virginia IGCC plant is $2.23 billion, which is much greater than the expected 20% premium for IGCC over SCPC. AEP has delayed the plant until 2015, unless the West Virginia Public Service Commission allows for recovery of these higher costs.*

- *<u>Cash Creek</u>: A draft permit has been issued by the Kentucky Department for Environmental Protection. Construction of Cash Creek is expected to begin in late 2007, pending financing and other project approvals, with commercial operation planned for 2011.*

- *<u>Excelsior-Mesaba</u>: Excelsior Energy's Mesaba IGCC project in Minnesota has recently faced disapprovals in its siting and permitting process, due to the high capital cost of the plant and its resulting high projected cost of electricity. In light of these events, the project may not be in operation by the target date of 2011, if at all.*

- *<u>Orlando Gasification</u>. The 285 MW Orlando Gasification demonstration plant, to be developed near Orlando, Florida will demonstrate the KBR transport reactor gasification technology, using PRB coal. The NEPA process was recently completed and a Record of Decision issued for DOE funding. Construction could begin in late 2007 and the 4.5 year demonstration phase in mid 2010. The purpose of this project is to demosntate a new type of gasification technology, which is not commercially available.*

- *<u>PMEC</u>: Energy Northwest's Pacific Mountain Energy Center was originally planned to begin operation in 2012. Recently, developers announced they were delaying the project, as it would not be able to comply with Washington State's new law requiring CO_2 capture and sequestration.*

- *<u>Steelhead</u>: Steelhead Energy Company's construction permit for an IGCC facility at the Southern Illinois Clean Energy Center is under review by the Illinois EPA. Although it was originally scheduled for a 2008 start-up, the application is currently inactive, and Steelhead is reassessing its plans. The project is unlikely to go forward.*

These projects underscore that IGCC remains an evolving technology, still largely at the demonstration stage, and lacking operational data and demonstrated emissions performance.

NPS Comment #2(2) (p. 3)

IGCC is currently 10% to 20% more expensive to build than an equivalent PC facility, but this cost disadvantage will be partially or entirely offset when national legislation requires CO_2 capture and sequestration. Furthermore, industry leaders have recently acquired the capability to bring the components of a complete 600 MW IGCC facility together in an integrated, cost-effective package.

Response: *Recent experience suggests that technology providers are not yet willing or able to offer a turnkey project with standard industry guarantees for cost, schedule, performance and emissions based on an IGCC reference plant and that a 10 to 20% premium for IGCC is far too low. IGCC technology suppliers are currently working to develop a standardized "reference plant" design that will function as the basis for engineering estimates of emissions and plant performance, as well as cost estimates and commercial guarantees. Reference plant designs assume low elevation and a feedstock of eastern bituminous coal, are sized at approximately 600 MW (net), and use a "2-by-2-by-1" configuration, meaning two commercial-sized gasifiers and syngas treatment systems, producing sufficient syngas to fully load two gas turbine generators, and one steam turbine generator. The high elevation, low rank feedstock and non-standard size for Dry Fork Station would further increase the costs of IGCC over PC, and would preclude taking advantage of the reference plant design.*

For a complete discussion of the commercial availability of IGCC, please see Exhibit 22, "A Comparison of PC, CFB and IGCC Technologies for Basin Electric Power Cooperative's Dry Fork Station" (2007 Technology Comparison) pp. 10-13, and the Response to ENV Comments #4 and 5, infra pp. 83-85.

Unlike ENV, the NPS does not contend that there is a legal duty to consider IGCC as an alternative to the proposed PC plant, but rather, believes that power generators should "take a serious look" at IGCC. A summary of Basin Electric's current activities responding to climate change issues is included in response to ENV Comment #3, infra pp. 66-69. Basin is currently working to develop renewable energy sources and support research in clean coal technology in advance of any federal legislation, and will comply with any future obligations that may be imposed by Congress or EPA.

NPS Comment #2(3) (p. 3)

While IGCC has not been successfully demonstrated with western sub-bituminous coal or at high altitude, these issues are not insurmountable. Two western IGCC projects (Bowie in Arizona and Xcel in Colorado) are moving toward reality.

Response: *The western IGCC projects cited by NPS are still years away from construction, and it will require several more years after that to develop robust experience operating IGCC on low rank coals and at high altitude. The Bowie plant is in the process of obtaining zoning approvals, and Xcel plans to approach the Colorado PUC for approval as part of its resource plan in late 2007, with construction expected to begin after 2009.*

These projects may signal optimism about the future capability of IGCC technology in the west, but as NPS concedes, they do not constitute a successful demonstration of IGCC with *western sub-bituminous coal or at high altitude. They do not demonstrate that IGCC can supply reliable baseload capacity within the timeframe in which additional resources are needed by Basin Electric.*

NPS Comment #3 (p. 3-4, 5)

Dry Fork has higher emissions per energy output than the limit proposed for FPL-Glades because the Glades boilers are more efficient.

Response: *The FPL-Glades project was rejected by the Florida Public Service Commission on June 5, 2007. The Florida Public Service Commission decided that the FPL-Glades proposal was not economically feasible for FPL's customers. Even so, Basin addresses the limit proposed for FPL-Glades in this response.*

FPL-Glades will be equipped with ultra supercritical pulverized coal technology. See FPL, "FPL Glades Power Park – Advanced Technology," available at http://www.fpl.com/environment/plant/gpp_tech.shtml (last visited 5/22/07). As Basin began design review for this project, it undertook an engineering analysis that considered whether the boiler should be supercritical or ultra supercritical. That review concluded that a supercritical or ultra supercritical boiler was not appropriate for this project because supercritical boilers are usually designed for a greater MW size (greater than 500 MW) and ultra supercritical boilers for even larger plants (greater than 800 MW). Supercritical and ultra supercritical boilers lose efficiency with smaller MW sizes. See Sargent & Lundy, Memorandum regarding Subcritical—Supercritical Boiler Comparison, June 11, 2007, Exhibit 7; see also Basin, Turbine Vendor Responses to Supercritical Units under 450 MW-gross, June 7, 2005 at 1-2 (Exhibit 8); Sargent & Lundy, Minimum Supercritical Steam Turbine Size, March 2005 at 1-4 (Exhibit 9).

The FPL-Glades Power Plant will consist of twin 980 MW units. See FPL, "FPL Glades Power Park – About the Project," available at http://www.fpl.com/environment/plant/gpp_about.shtml (last visited 5/22/07). The Dry Fork Station power plant will consist of a single 422 MW (gross) unit. FPL's ability to use ultra supercritical technology because of the greater MW size of their boilers has enabled FPL to propose a lower emissions per energy output than the proposed Dry Fork Station. Dry Fork Station does not have the same ability as FPL to use ultra supercritical technology because of the smaller MW size of the Dry Fork Station boilers.

<u>*Analysis of Supercritical technology*</u>

Basin compared the technical and economic feasibility of designing the proposed Dry Fork boiler as either an advanced subcritical boiler or a supercritical boiler. The Permit Application described the proposed Dry Fork boiler as an indoor-type pulverized coal (PC) fired boiler designed for baseload operation. The unit will have a maximum heat input of approximately 3,801 MMBtu/hr, a maximum gross generation output of approximately 422 MW, and a net generation output of approximately 385 MW at annual average conditions. Average net generation will be slightly lower during summer maximum ambient temperature conditions due to the use of an air cooled condenser. The proposed boiler is being designed to be capable of developing main steam turbine throttle pressures and temperatures in the range of 2,520 psig *and 1,050 °F, respectively, and a reheat steam temperature at the inlet of the intermediate pressure turbine of approximately 1,050 °F. The proposed main steam turbine throttle pressure is below the critical point of water, therefore, the boiler will be classified as a subcritical PC boiler.*

The decision to propose a PC boiler for Dry Fork Station was based on an engineering evaluation of the available coal-based electricity generating technologies conducted by CH2M-Hill prior to submittal of the air construction permit application. "Coal Power Plant Technology Evaluation for Dry Fork Station," CH2M-Hill, November 1, 2005 (2005 Technology Evaluation), Exhibit 10. That report provided a conceptual level technology evaluation to address the advantages and limitations of PC boilers, circulating fluidized bed (CFB) boilers, and integrated gasification combined-cycle (IGCC) power generating technologies. The various generating technologies were evaluated with respect to Basin Electric's defined needs for baseload capacity, environmental compliance, reliability and availability, commercial availability, and economic criteria. The evaluation concluded that "PC technology is capable of fulfilling Basin Electric's need for new generation, and is recommended for the NE Wyoming Power Project [Dry Fork]."

The technology evaluation included a review of the advantages and disadvantages associated with subcritical and supercritical PC steam cycles and the associated equipment, and concluded that:

> *"[a] Basin Electric 250 MW PC unit would use a subcritical steam cycle design. The additional capital cost for a supercritical cycle is typically only justified by the efficiency improvement for PC units of 350 MW and larger. There is also a minimum 350 MW size limitation due to the first stage design of the steam turbine."*

2005 Technology Evaluation at 18.

Subsequently, Basin's projected baseload power requirements increased from 250 MW to 385 MW (net), and the gross electrical output of the proposed boiler increased to 422 MW (gross). The following analysis updates the comparison of subcritical and supercritical PC steam cycles at the proposed 422 MW (gross) level, drawing on Sargent & Lundy, Memorandum regarding Subcritical—Supercritical Boiler Comparison, June 11, 2007, Exhibit 7.

Subcritical and Supercritical PC Units

Coal-fired units can be classified by their main steam turbine operating pressure and temperature. Units operating at a main steam pressures and temperatures above the critical point of water (approximately 3,208 psia and 705°F) are termed "supercritical" units. Units operating below the critical point of water are termed "subcritical" units.

In a subcritical boiler, water circulating through tubes that form the furnace wall lining absorbs heat generated in the combustion process which, in turn, generates steam by the evaporation of part of the circulated water. Saturated steam produced in the boiler must be separated from the water before it enters the superheater. Subcritical units utilize a steam drum *and internal separators to separate the steam from the water circulating in the boiler tubes. The temperature of the boiler steam is increased in the superheater above the saturated temperature level. As steam enters the superheater in an essentially dry condition, further absorption of heat sensibly increases the steam temperature. The reheater receives superheated steam which has partially expanded through the turbine. The role of the reheater in the boiler is to re-superheat the steam to a desired temperature.*

Modern subcritical units have a maximum turbine throttle pressure of approximately 2,520 psig. Turbines for 2,400 psig operation are usually designed for steam pressures of 2,520 psig at the turbine throttle – a condition of 5% overpressure. A boiler-drum operating pressure of between 2,750 and 2,850 psig is required to allow for pressure drop through the superheater and the main steam line. Main steam pressure and temperature, and reheat temperatures of new subcritical units (2,520 psig / 1,050°F / 1,050°F) are significantly higher than pressures and temperatures achievable with older units (typically in the range of 2,400 psig, 1,000°F / 1,000°F). Increased pressures and temperatures have improved the plant heat rate of subcritical units by approximately 2%.

Supercritical boilers operate at a main steam pressure above the critical point of water (3,208 psia). When water is heated at a pressure above 3,208 psia it does not boil; therefore, it does not have a saturation temperature nor does it produce a two-phase mixture of water and steam. Instead, the water undergoes a transition in the enthalpy range between 850 and 1,050 Btu/lb. In this range its physical properties (including density, compressibility and viscosity) change continuously from those of a liquid (water) to that of a vapor (steam), and the temperature rises steadily. Supercritical steam boilers are "once-through" boilers and do not require the use of a boiler drum to separate steam from water. In a supercritical boiler all of the boiler feedwater is turned into steam. Supercritical PC units are typically designed to develop a main steam turbine throttle pressure and temperature in the range of 3,500 to 3,600 psig and 1,050°F, and a reheat steam temperature of 1,050°F.

Unit Efficiency

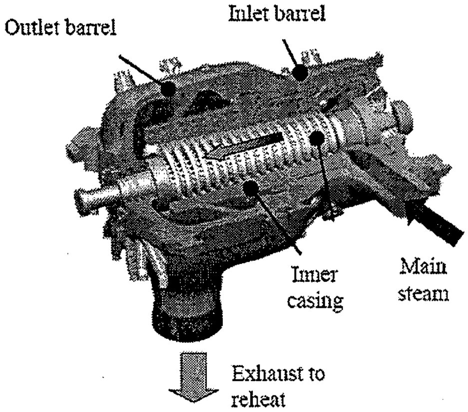
The efficiency of the thermodynamic process of a coal-fired unit depends upon how much of the heat energy that is fed into the cycle is converted into electrical energy. The throttle pressure and temperature of a subcritical cycle is limited by the properties of water, which limits the amount of heat energy that can be converted into working steam. The throttle pressure and temperature of a supercritical cycle is not limited by the properties of water, but by the capabilities of the materials used in the boiler, piping, and turbine. Therefore, more heat energy can be utilized in a supercritical cycle. If the energy input to the cycle remains constant, output can be increased with elevated pressures and temperatures for the water-steam cycle. Output is increased with increase steam flow (at high pressures) through the steam turbine.

There are several turbine designs available (unique to each supplier) for use in supercritical power plants. Turbines designed for use in supercritical applications are fundamentally similar to turbine designs used in subcritical power plants. For a single reheat supercritical unit with a power output in the range of 600 – 1,000 MW, a typical turboset design would consist of three separate turbine modules operating at different pressure and temperature levels. Rosenkranz, J., Wichtmann, A., "Balancing Economics and Environmental Friendliness

– The Challenge for Supercritical Coal-Fired Power Plants with Highest Steam Parameters in the Future," Siemens-Westinghouse, Study supported by funds provided by the German Federal State of North Rhine-Westphalia (European Regional Development Fund – ERDF), [registration number 85.65.69-T-138]. These three modules are the high pressure (HP) turbine, the intermediate pressure (IP) turbine, and the low pressure (LP) turbine section (which will have one, two or three sections depending on the unit size). The generator is directly coupled to the last LP turbine.

In the HP turbine steam is expanded from the main steam turbine throttle pressure to the pressure of the reheat system. Because of the high pressures associated with supercritical cycles, the inlet volumetric flow to the HP turbine is significantly lower than the inlet volumetric flow to the HP turbine on a subcritical unit. Turbine manufactures have designed HP turbine blades specifically for use with supercritical cycles to account for this reduced volumetric flow. One HP turbine design capable of handling supercritical main steam conditions is the barrel type outer casing design, shown as a cross-section below. The high temperature components of the supercritical HP turbine, such as the inlet nozzle, rotor, and inner casing must be made with advanced types of steel (e.g., 9-12% CrMoV steel).

The steam flow is further expanded in the IP turbine section. In both subcritical and supercritical cycles there is a trend to increase the temperature of the reheat steam that enters the IP turbine section in order to raise the cycle efficiency. In the LP turbine section the steam is expanded down to the condenser pressure. There are no significant differences between the IP and LP turbine sections of a supercritical and subcritical plant.



Source: Siemens-Westinghouse

Supercritical Efficiencies and Unit Size

Efficiencies achievable with supercritical cycles are a function of the pressures and temperatures that can be developed in the boiler and the steam flow through the HP turbine. Although a few supercritical units have been built at outputs in the range of 300 – 500 MW, the vast majority of the supercritical units that have been built have been at a 500 MW gross rating or larger. At the larger sizes, volumetric steam flow through the HP turbine is large enough to *accommodate larger HP first stage blades. Blade size and design is one of the most important components of overall turbine performance. For unit sizes of 500 MW or more, cycle efficiency improvements will be in the range of 1.5 – 2.0% with supercritical units. Depending on other parameters affecting plant efficiency (e.g., auxiliary power requirements), this difference in cycle efficiency results in a gross plant heat rate (Btu/MW-gross) improvement of approximately 2 to 3%. In other words, less fuel needs to be burned to generate the same electrical output.*

Low inlet volumetric flow to the HP turbine (associated with supercritical pressures) is one of the main reasons supercritical units have not been typically considered for sizes less than approximately 500 MW. As size decreases below 500 MW, efficiency improvements associated with the higher inlet pressures are reduced. Some of the decrease in efficiency is due to the necessary application of very short turbine blading in the early HP stages due to the reduced volumetric flow associated with the higher inlet pressure. The shorter blades used with high pressure cycles will still be mounted on relatively high base diameters so that acceptable rotor dynamics can be achieved. This results in a high ratio of seal clearance area to nozzle flow area as compared to a higher MW rated unit with taller blades. The increased pressure and reduced volumetric flow results in increased nozzle edge friction loses and seal loses, reducing efficiency improvements in the HP turbine.

Furthermore, since there is very little demand for supercritical equipment at sizes below approximately 500 MW, OEMs typically apply available HP turbine elements at the low end of their application range (which would be larger than necessary) to avoid one time engineering costs for new one-of-a-kind smaller units. This approach would result in the HP blades being set on a higher base shaft diameter than would be used if the elements were designed specifically for the high pressure low output condition. The resulting design would not be optimal thermodynamically, further increasing nozzle edge losses and seal losses.

Technical issues associated with high pressure, low volumetric flow, and short turbine blading in the early HP stages will significantly reduce efficiency improvement gains in the HP turbine associated with supercritical cycles. Reduced efficiency gains in the early HP stages will reduce expected cycle efficiency improvements from the 1.5 – 2.0% range on larger units (500 MW and larger) to approximately one-half that benefit as unit output is reduced down toward the 250 MW level. Discussions with the OEMs conducted as part of the technology review process were consistent on two important issues; (1) the commonly accepted break point to justify the increased costs for the efficiency gains associated with a supercritical unit is above 500 MW; and (2) in the smaller MW sizes the cycle efficiency improvements would diminish to less than one-half of the gains achievable with larger units.

Auxiliary Power Requirements

Auxiliary power requirements will also affect the gross plant heat rate of the unit. Everything else being equal, fan requirements for supercritical units are slightly less than the requirements for a similarly sized subcritical unit because of the reduced combustion air and flue gas flows. However, other project unique design requirements will impact the auxiliary power and overall unit efficiency.

As noted earlier, an air cooled condenser (ACC) is being used at Dry Fork, primarily due to a lack of sufficient water to support a water cooled condensing system. Air cooled condensing systems require greater auxiliary power than water cooled condensing systems, and result in greater variations in turbine backpressure compared to water cooled condensing systems. In addition, turbine driven feedpumps, which are often applied to improve overall unit efficiency, are typically not used with an ACC because the additional steam flow from the feedpump turbine would require a larger condenser (and associated auxiliary power consumption) and would not operate as efficiently as motor driven feedpumps because turbines operate efficiently only within a relatively narrow backpressure range. Therefore, motor driven feedpumps have been selected for Dry Fork.

For large supercritical units (e.g., >500 MW) with turbine-driven boiler feed pumps, base auxiliary power requirements will be slightly less than the auxiliary power requirements of a similarly sized subcritical unit because of the efficiency of the turbine-driven feed pumps and the reduced fan requirements. However, for the Dry Fork design, which uses motor driven feedpumps, the auxiliary power requirements for supercritical units would be in the range of 3.14 % of gross generator output compared to approximately 2.17% for subcritical units. This difference more than offsets the slight reduction in fan requirements.

Although the Dry Fork unique design considerations indicate that higher pressures associated with a supercritical unit will not significantly improve efficiency, higher steam temperatures can still be used. The Dry Fork boiler is being designed with the advanced subcritical steam cycle conditions inlet to the turbine of 2,520 psig, 1050°F / 1050°F. These increased pressures and temperatures will improve the heat rate of the plant by approximately 2% compared to subcritical conditions of 2,400 psig / 1,000°F / 1,000°F.

Commercial Availability at 422 MW

Supercritical units being planned for the United States are in the 500 MW gross rating or larger size. Although a few supercritical units have been built at sizes below 500 MW, turbine suppliers do not offer turbine designs for smaller supercritical steam flows. Based on discussions with OEMs conducted during the technology review process, suppliers advised that supercritical turbine designs below approximately 500 MW would be a one-of-a-kind application, and would require significant up-front design and engineering that OEMs are unable to provide in a competitive environment. Since there is very little demand for supercritical equipment at sizes below approximately 500 MW, turbine vendors would likely apply available HP turbine elements at the low end of their application range to avoid the one-time engineering costs. These HP turbine elements would be larger than necessary, further reducing potential efficiency gains with the supercritical cycle.

Likewise, given current market conditions, the boiler suppliers would not be interested in bidding a one-of-a-kind application, and concern regarding their ability to prepare a competitive offering on a small supercritical unit.

Given this feedback, it was determined to be impractical to obtain competitive bids on the two major pieces of equipment, further increasing the cost penalty for selecting a supercritical cycle.

Conclusions

Although some supercritical units have been built at output levels below 500 MW, a larger majority of the supercritical units that have been built have had a gross output rating of 500 MW or more. At larger output ratings, volumetric steam flow through the HP turbine is large enough to accommodate larger first stage blades in the HP turbine, and achieve cycle improvement efficiencies in the range of 1.5 – 2.0%. The smallest application limit for supercritical boiler/turbine designs would be defined by the HP blading design (i.e., blade height), and would be in the in the range of approximately 200 to 300 MW-gross. However, below approximately 500 MW, efficiency differences between sub- and supercritical cycles become smaller because the low volumetric flows to the HP turbine. Finally, auxiliary power requirements for a supercritical unit at Dry Fork are higher than the auxiliary power requirements for subcritical units due to the use of motor-driven boiler feed pumps.

Sargent & Lundy (S&L) prepared heat balances and performance calculations for both subcritical and supercritical units using Dry Fork specific design criteria (e.g., fuel specifications, ambient conditions, air cooled condensing system, feedpump drivers, etc.). Heat balances and performance calculations were prepared taking into consideration expected HP turbine efficiency gains and auxiliary power requirements. The calculations indicate that net plant heat rates for either the sub- or supercritical cycle would be approximately the same. This occurs because of the minimal efficiency gains expected with small supercritical steam flows (in the range of 0.75% because of the small first stage HP turbine blades) and the impact of additional auxiliary power requirements associated with the motor driven boiler feed pumps. Table 1 below summaries the performance data for this case.

Table 1

		Subcritical	**Supercritical**
Gross Turbine heat rate(Annual Average conditions)	Btu/kW-gross	7436	7269
Aux Power	%	8.41	9.30
Boiler efficiency	%	86	86
Net Plant Heat Rate (no margin included)	Btu/kw-hr -net	9440	9319
Plant efficiency	%	36.14	36.61
Difference	%	Base	0.47
Note, this difference is less than the estimated 0.75% due to the application of motor - driven feedpumps, as mentioned earlier. Based on the feedback from the turbine vendors, stated earlier, it's reasonable to estimate that the 0.47% difference shown would be even less, due to the turbine's HP-section inefficiency on smaller size units.			

Therefore, there is no technical basis, nor environmental justification, for designing the proposed Dry Fork boiler as a supercritical unit. Finally, the costs associated with designing the unit for a supercritical cycle would increase overall plant costs by approximately 2 to 4%, and most likely closer to the high value due to the reverse economy of scale effect.

<u>Consideration of the Glades Project</u>

It is also axiomatic that BACT does not require that an applicant redefine the project. In a recent PSD permit decision, the EAB determined that Prairie State did not need to use low sulfur coal because that would redefine the project:

> *The statute contemplates that the permit issuer must look to the permit applicant to define the proposed facility's purpose or basic design in its application, at least where that purpose or design is objectively discernible ....This approach not only harmonizes the BACT definition with the permit application process in which the definition must be applied, but also is consistent with the Agency's longstanding policy against redefining the proposed facility.*

Prairie State EAB Decision at 1-2. It, thus, stands to reason that Basin should not be required to consider an entirely different boiler design as BACT. While Basin initially considered the potential for using a supercritical boiler in its initial design engineering phase of this project, it ~~determined that that technology was not appropriate for the small size of the Dry Fork plant.~~

Not only is the FPL-Glades facility proposing to utilize a supercritical boiler, but the FPL-Glades plant will also burn a higher sulfur fuel mix including petroleum coke and is located within 70 miles of a Class I area. As such, it was incumbent on that project to achieve extraordinarily low SO_2 control rates. As the NPS notes in its comments, the closer a project is to a Class I area, the greater the emission control that will be required, especially a project that is nearly 2000 MW, one of the largest currently being permitted.

Further, the Glades facility has not been constructed and has not demonstrated that it can meet its BACT limits in practice. A permit issuer may appropriately consider, as part of its BACT analysis, the extent to which available data in the record evidence the ability to consistently achieve certain emissions rates or control effectiveness of the selected technology or pollution control method. Newmont EAB Decision at 15. Since Glades is not yet operational, there is no data showing the plant will achieve its reported emissions per energy output limit. Further, permitting agencies have discretion in determining whether a particular control efficiency level is appropriate in determining BACT and in setting an appropriate emissions limit. Newmont EAB Decision at 42. The emissions per energy output limit is not an appropriate consideration in determining BACT for the Dry Fork plant because of the different boiler technology used at the Glades plant, and the concern Basin has that it will not be able to consistently achieve the Glades' limits.

NPS Comment #4 (p. 4-5)

Wyoming must show why dry scrubbing technology was selected over wet scrubbing technology at Dry Fork, and why application of wet scrubbing would present unique disadvantages at its specific site relative to other wet scrubber installations such as Desert Rock and Glades.

***Response**: The FPL-Glades project was rejected by the Florida Public Service Commission on June 5, 2007. The Florida Public Service Commission decided that the FPL-Glades proposal was not economically feasible for FPL's customers. Even so, Basin addresses the wet-scrubber installation proposed for FPL-Glades in this response.*

A detailed analysis of why Basin selected dry scrubbing technology over wet scrubbing technology at Dry Fork was provided in Basin's SO_2 BACT analysis for the Dry Fork boiler as part of the original Permit Application submitted in November 2005 and as provided in its March 2006 and July 14, 2006 Responses. Permit Application, Sec. 5.2.3 (SO_2); March 2006 Response, at Attachment No. 1 (SO_2) (Exhibit 3); July 14, 2006 Response at 3-5 (Exhibit 4). In conducting that analysis, Basin identified two potential SO_2 control technology options: dry scrubber (SDA or CDS), and wet scrubber (wet flue gas desulfurization (FGD)). Basin found both technologies to be technically feasible. Permit Application at Sec. 5.2.3. Basin then assessed the relative control efficiencies of the two technologies for purposes of determining how to rank them in order of control effectiveness. Basin determined that the control efficiencies of wet and dry scrubbing technologies were relatively equal.

Basin's assessment of the relative control efficiencies of wet and dry scrubbing technologies for purposes of determining how to rank them in order of control effectiveness is consistent with EPA findings. While wet-scrubbing generally achieves greater control efficiency than dry-scrubbing when higher sulfur coals are used, based on an EPA report addressing SO_2

emissions control technologies, when low sulfur PRB coal is used, the control effectiveness of the two technologies is virtually indistinguishable. See "Controlling SO_2 Emissions: A Review of Technologies," USEPA/600R-00/093 (November 2000). Thus, wet scrubbing and dry scrubbing technologies rank as equivalent for purposes of sulfur control on low sulfur PRB coal. Further, according to recent available Energy Information Administration (EIA) data, wet and dry scrubbers placed in service since 1990 have essentially identical average control efficiencies based on actual test data: 89.6% control for wet scrubbers and 89.8% control for dry scrubbers. Average reported test results derived from Form EIA-767 "Steam-Electric Plant Operation and Design Report" 2004 reporting year, http://www.eia.doe.gov/cneaf/electricity/page/eia767.html. Summarizing these facts, Nevada DEP recently stated in the Response to EPA Region 9 Comments on Draft Operating Permit to Construct AP4911-1349 for Newmont Nevada Energy Investments, LLC – TS Power Plant: "Based on an EPA report and review of vendor information for wet and dry FGD processes, BAPC concluded that for higher sulfur coals wet scrubbing achieves better control, however, for lower sulfur Powder River Basin (PRB) coals, the efficiencies become so close as to be indistinguishable within their respective margins of error." Exhibit 11.

Basin concluded that the two technologies ranked as equivalent for purposes of sulfur control on low sulfur PRB coal. Permit application at Sec. 5.2.3. Basin then considered the energy, environmental, and economic costs of the two equivalent control options. The dry-scrubber had lower energy consumption than the wet-scrubber, it provided greater environmental benefits in the form of reduced acid gases (H_2SO_4) and reduced condensable PM_{10} emissions. The dry fly ash byproduct from the dry-scrubber has lower environmental impacts than the fly ash slurry discharge resulting from a wet-scrubber. Lastly, the wet-scrubber is significantly more expensive than the dry-scrubber, in terms of both capital and operating costs. Thus, given the equivalent control effectiveness of the two options, and the greater adverse energy, environmental, and economic impacts of the wet-scrubber, Basin's BACT analysis selected a dry scrubber.

The EPA NSR Workshop Manual envisions just this type of situation: "For example, if two or more control techniques result in control levels that are essentially identical considering the uncertainties of emission factors and other parameters pertinent to estimating performance, the source may wish to point this out and make a case of evaluation of only the less costly of these options." EPA NSR Workshop Manual, October 1990 Draft, ("EPA NSR Manual") at B.20-21.

<u>Economic Impact</u>

The following evaluation considers the cost effectiveness of the primary control options. The SO_2 BACT determination does not rest entirely or even principally on the economic impacts as is evident by the documented environmental and energy impacts to follow, which by themselves provide sufficient justification for the control technology decision on wet scrubbing.

EPA has consistently stated that the economic analysis should evaluate the average cost and the incremental cost as part of the analysis. For example, EPA's NSR Manual directs that, "[i]n addition to the average cost effectiveness of a control option, incremental cost effectiveness between control options should also be calculated. The incremental cost effectiveness should be *examined in combination with the average cost effectiveness in order to justify elimination of a control option." EPA NSR Manual at B.41 (Additional support for the importance of considering both average and incremental cost are provided in the following: Final Order, In Re Inter-Power of New York, Inc., March 16, 1994 and January 19, 2001 Memorandum from John S Seitz, Director to Air Division Directors, Regions I-X, "BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Sulfur Refinery Projects."). In the Final Order in* *__In Re Inter-Power of New York__*, *the Judge stated that "[u]ltimately, a control option may be rejected where the costs for the option 'would be disproportionately high when compared to the costs normally associated with BACT for the type of facility (or BACT control costs in general) for the pollutant." EAB PSD Appeal Number 92-8 and 92-9 (March 1994), at 136.*

Multiple state agencies have acknowledged incremental cost as a contributing factor in BACT determinations. For example, in the Permit Analysis for the Neil Simpson Unit II, WDEQ stated that the high incremental costs associated with a wet scrubber coupled with the high capital costs of the system made a dry scrubber system a more economically attractive alternative. WDEQ, Permit Analysis for Neil Simpson Unit II, April 14, 1993. Additionally, Nevada DEP recently stated that the incremental cost associated with wet scrubbing for Newmont's proposed facility would far exceed the environmental benefit from the modest reduction in SO_2 emissions that might be possible. Response to EPA Region 9 Comments on Draft Operating Permit to Construct AP49 11-1349 for Newmont Nevada Energy Investments, LLC — TS Power Plant, (Nevada Response to EPA) at 4-5. Exhibit 11.

Basin's March 2006 Response at Attachment No. 1, (SO_2) Exhibit 3, showed that the incremental cost effectiveness of WFGD was \$12,610 (at 0.07 lb/MMBtu) to \$24,052 (at 0.09 lb/MMBtu) per ton SO_2 removed compared to the SDA case at 0.10 lb/MMBtu. The average annual cost effectiveness of WFGD was \$1,631 (at 0.07 lb/MMBtu) to \$1,461 (at 0.09 lb/MMBtu) per ton SO_2 removed. Based on the incremental cost effects, in addition to the collateral environmental impacts identified in the Permit Application and discussed below, WFGD was eliminated from consideration as BACT. See July 14, 2006 Response at 4. At the current proposed permit limit of 0.08 lb/MMBtu, the incremental costs for WFGD increase to \$18,538 (at 0.07 lb/MMBtu), and the average annual cost effectiveness is \$1,631 per ton SO_2 removed. March 2006 Response at Attachment No. 1 (Exhibit 3).

__Energy Impact__

In addition to the economic impacts, wet scrubbing was found to have much greater energy and environmental impacts than dry scrubbing at Dry Fork. A dry scrubber system has the advantage of requiring less electric power for its operation compared to a wet scrubber system. Heat input to the boiler would need to increase by approximately 1.5% with the wet FGD to achieve the same net plant output. The calculated maximum heat input to the boiler with the dry FGD configuration is 3,801 MMBtu/hr. To achieve the same net output with a wet FGD the maximum heat input would need to increase approximately 3,858 MMBtu/hr, increasing NO_x, CO, PM_{10}, and VOC emission on a per MW-generated basis.

Alternatively, Basin could design the proposed unit with dry FGD and reduce net plant output from 385 MW to approximately 380 MW without an increase in collateral emissions.

However, the lost output (approximately 43,800 MW-hr annually) would need to be replaced with power from existing power stations. Most existing power stations emit significantly more pollutants per MW output than the proposed Dry Fork Station.

Further, the annual power savings resulting from the use of a dry scrubber would provide enough energy for several thousand homes. See http://www.utilipoint.com/issuealert/print.asp?id= 1728. Thus, the energy requirements for wet scrubbing represent a negative energy impact. Installing a control technology that would consume the energy equivalent of several thousand homes would not represent a judicious use of energy by the Dry Fork plant.

Environmental Impact

Additionally, the use of a wet scrubber at Dry Fork would result in great environmental costs. An evaluation of the environmental impacts is included below, organized by environmental impact type.

Water Impacts — Water Consumption

Campbell County, Wyoming, is considered a semi-arid region due to annual rainfall of only 10-15 inches. See WDEQ, Natural Events Action Plan for the Coal Mines of the Powder River Basin of Campbell and Converse Counties, Wyoming, October 2006, at 2 (Since 1996, the average annual precipitation has been 14.29 inches). Thus, water consumption is an important consideration in the BACT determination. In the October 28, 2005, Clean Air Mercury Rule (CAMR), EPA recognized that water availability must play a role in control technology determinations for areas that receive less than 25 inches of precipitation per year. EPA stated that for new subbituminous coal-fired units located in an area receiving less than 25 inches of precipitation per year, Best Demonstrated Control Technology (BDT) is considered a dry FGD system. 70 Fed. Reg. 62216 (Oct. 28, 2005). The EPA NSR Manual also discusses the unusual circumstance/cost of water for a scrubbing system in an arid region. EPA NSR Manual. at B.44.

Further, multiple state agencies have acknowledged increased water consumption for wet scrubbers as a negative environmental impact affecting BACT determinations. For example, the WDEQ permit analysis for the Neil Simpson Unit II listed an additional 20% to 30% more water required for a wet scrubber. The WDEQ analysis stated that water usage was a primary environmental concern and of special importance in that semi-arid part of the country. WDEQ, Permit Application Analysis for Neil Simpson Unit II (April 14, 1993). Additionally, the Montana Department of Environmental Quality (MDEQ) permit analysis for the Roundup power plant estimated that wet scrubbing for the two 390 MW units proposed would require 420.5 million gal/year in comparison to 304.8 million gal/year required for dry scrubbing (38% more). MDEQ listed the higher water consumption rate among the determining collateral environmental impacts that eliminated wet scrubbing from consideration as BACT. MDEQ, Permit No. 3 182-00 (July 21, 2003).

As EPA and state agencies have recognized, a wet scrubber system has a much greater water consumption than a dry scrubber system. Based on preliminary engineering calculations for Dry Fork, it is estimated that a wet FGD system would require at least 30% more water than a dry system, or approximately 200 million gallons per year. It is in the best interest of this *semi-arid region to minimize water consumption and allow for future residential, commercial, and industrial growth in the area. Given that the Dry Fork plant will be located in a semi-arid region, the water consumption impacts for wet scrubbing represent a negative environmental impact.*

Air Impacts — Emissions

While estimated SO_2 emissions might be lower for wet scrubbing, a wet scrubber would result in higher levels of total air emissions, particularly for other PSD pollutants and hazardous air pollutants (HAPs). Pursuant to the EPA NSR Manual, a PSD permitting authority should consider the effects of a given control alternative on emissions of toxics or hazardous pollutants not regulated under the Clean Air Act. Id. at B.50.

Emissions of HF, H_2SO_4, and other criteria pollutants (excluding SO_2) are a negative environmental impact for wet scrubber systems. For the Dry Fork plant, additional emissions of these pollutants would be significantly higher. Emitting significantly higher levels of HAPs (i.e., HF) and other PSD pollutants (i.e., H_2SO_4 and non-SO_2 criteria pollutants) with a wet scrubber would be an undesirable compromise for the marginally better SO_2 performance that might be achievable. EPA's NSR Manual reinforces this determination:

> *On occasion, consideration of toxics emissions may support the selection of a control technology that yields less than the maximum degree of reduction in emissions of the regulated pollutant in question. An example is the municipal solid waste combustor and resource recovery facility that was the subject of the North County remand. Briefly, BACT for SO_2 and PM was selected to be a lime slurry spray drier followed by a fabric filter. The combination yields good SO_2 control (approximately 83 percent), good PM control (approximately 99.5 percent) and also removes acid gases (approximately 95 percent), metals, dioxins, and other unregulated pollutants. In this instance, the permitting authority determined that good balanced control of regulated and unregulated pollutants took priority over achieving the maximum degree of emissions reduction for one or more regulated pollutants. Specifically, higher levels (up to 95 percent) of SO_2 control could have been obtained by a wet scrubber.*

EPA NSR Manual at B.53.

In the North County case, the EAB held that the permitting authority's selection of dry scrubbing over wet scrubbing was justified because of the greater control over HAP emissions (at that time unregulated pollutants) despite evidence that the wet scrubber would have provided greater control of SO_2 emissions from the high sulfur coal (95% v. 83%). In the Matter of: North County Resource Recovery Associates, 2 E.A.D. 229 (EAB 1986); EPA NSR Manual at B.53). Where, as here, there is not even evidence that wet scrubbing would produce greater control of SO_2 emissions, (or only marginally better control but at an uneconomic price) the *additional control of HAPs further underscores that a dry scrubber is the best available control technology for control of SO_2 emissions at the Dry Fork Station power plant.*

Additionally, a wet scrubber is placed downstream of the particulate control device; therefore any saturated droplets or particulates emitted from the wet scrubber are emitted to the atmosphere, increasing the PM_{10} emission rate as well as the trace metal constituents contained in the particulate matter. And, fine particulate emissions would be higher with wet scrubbing. The emission of fine particulate will be an even more significant issue in the future with the implementation of $PM_{2.5}$ regulations. Even after taking into account the potential for marginally better SO_2 removal efficiency associated with wet scrubbing, Basin estimates that wet scrubbing would result in much greater total emissions.

Other environmental impacts of a wet scrubber include:

Air Impacts — Fugitive Emissions: Fugitive PM/PM_{10} emissions from a wet scrubber would result from the storage and handling of the limestone and the handling and disposal of the large amount of byproducts. These low-release height fugitive emissions typically manifest their highest ambient concentrations just beyond the facility boundaries. While fugitive dust would not cause an exceedance of the NAAQS, activities that result in fugitive dust emissions should be avoided to the extent practicable.

Air Impacts — Visible Plume: A visible plume can result from a wet scrubber under a variety of ambient conditions. Visible plumes are often perceived negatively by the public and are considered undesirable.

Air Impacts — Concentrations: A wet scrubber would emit a cooler plume, which would result in less plume rise and higher ambient impacts.

Water Impacts — Wastewater: Wet scrubbers produce a wastewater stream due to the dewatering of the scrubber byproduct. Wastewater from a wet scrubbed plant would have higher concentrations of heavy metals and chlorides that might have to be treated before discharge to the facility's evaporation pond. Additionally, a wet scrubber system would require a larger evaporation pond.

Solid Waste Impacts: A wet scrubber would produce more solid waste. The extra waste produced by a wet scrubbed facility would consume a large additional disposal area space.

Based on the negative energy, environmental, and economic impacts documented above, wet scrubber technology was not selected as SO_2 BACT for the Dry Fork boiler. Considering the marginal SO_2 control efficiency that might be gained from the use of a wet scrubber, the additional energy consumption, water consumption, air emissions, visible plume, wastewater impacts, solid waste generation, and high incremental cost would be an undesirable compromise.

Wet Scrubber Installations at Desert Rock and Glades

Finally, directly comparing application of wet scrubbing at the Dry Fork plant to other wet scrubber installations such as Desert Rock and Glades is not straightforward. Desert Rock and Glades reportedly achieve higher control efficiencies using wet scrubbers than Dry Fork achieves with a dry scrubber. However, as discussed above, the control efficiency of a given SO_2 control technology is dependent on the SO_2 content in the incoming flue gas stream, and the inlet SO_2 content is directly proportional to the sulfur content of the coal. In applications where a high sulfur coal is used, the control efficiency can be higher than in applications where a low sulfur coal is burned. For this reason, caution must be used when attempting to apply the reported control efficiency for facilities burning high sulfur coal to facilities burning low sulfur coal.

For instance, the FPL-Glades plant not only utilizes ultra supercritical boiler technology because of its large MW size, but Glades also proposes to use eastern bituminous coals with co-firing of petroleum coke. See FDEP, Response to DEP (March 2, 2007), available at http://www.dep.state.fl.us/AIR/permitting/construction/fplglades/ResponsetoDEP.pdf, pp. 35-36 (last visited 5/23/07). Glades' use of higher-sulfur coal is likely the reason Glades was able to propose a greater control efficiency.

Similarly, the Desert Rock facility will utilize a different design (two supercritical coal boilers), a different capacity (1500 MW), and a different fuel (bituminous coal from the Navajo mine). Newmont EAB Decision at 19-25 (discussing Desert Rock facility); see also Desert Rock Energy Project, available at http://www.desertrockenergy.com/ (last visited 6/7/07). Again, this higher-sulfur coal is likely to result in higher control efficiencies. Further, the Desert Rock project will be used to demonstrate the commercial viability of an unproven proprietary sorbent injection process/chemical as a means of controlling SO_2 and acid gases (Per the facility's construction permit application dated May 7, 2004). This technology has not been proven effective in practice.

Further, neither the Desert Rock or the Glades facility have been constructed and neither facility has demonstrated that it can meet its SO_2 BACT limit in practice. In fact, the Glades project was rejected by the Florida Public Service Commission on June 5, 2007. A permit issuer may appropriately consider, as part of its BACT analysis, the extent to which available data in the record evidence the ability to consistently achieve certain emissions rates or control effectiveness of the selected technology or pollution control method. Newmont EAB Decision at 15. While previous permit decisions can provide guidance for future BACT determinations, permitting agencies must establish BACT on a case-by-case and facility-by-facility basis. EPA's NSR Workshop Manual states the following regarding the basis for BACT limits:

> *Manufacturer's data, engineering estimates and the experience of other sources provide the basis for determining achievable limits. Consequently, in assessing the capability of the control alternative, latitude exists to consider any special circumstances pertinent to the specific source under review, or regarding the prior application of the control alternative.*

EPA NSR Manual at B.24.

The Desert Rock and Glades plants utilize different technology, have different capacities and will use different coal than the Dry Fork plant. While wet scrubbing technology may be appropriate for higher sulfur fuels, such as those at Desert Rock and Glades, data show that wet scrubbing efficiencies drop off as coal sulfur content decreases. Not surprisingly, as a result, almost all operating power plants exclusively burning PRB coal that Basin located use dry scrubbers. As a result, the data on the control efficiency of a wet scrubber exclusively burning PRB coal is too limited to support a conclusion that wet scrubbers are more efficient than dry scrubbers for SO_2 removal.

<u>*Other Permitting Decisions*</u>

Finally, other permitting agencies have also determined that a dry scrubbing system is appropriate for plants like Dry Fork that use PRB coal. In the recent response to comments for the City Utilities of Springfield coal-fired power plant PSD permit, the Missouri Air Pollution Control Program provided the following response supporting its selection of a dry scrubber as BACT for SO_2 emissions:

> *In regards to SO_2 emissions, the Air Program looked at several different types of control options. It was determined that wet flue gas desulfurization (wet FGD) or dry flue gas desulfurization (dry FGD) provided the best, proven technology for SO_2 control. Both of these technologies have been presented as BACT in recent proposed and final permits. The Air Program acknowledges that the wet FGD systems provide slightly better controls for SO_2 than dry FGD systems do. The use of wet FGD systems versus a dry FGD system will result in a significant energy penalty to facility operation in the form of electricity demand required for operations of ancillary equipment. The wet FGD will have an additional back pressure on the exhaust system that results in a slight reduction in output. As a result of the increased energy demands, the boiler would have to be sized bigger and combust more fuel in order to produce the same net electrical output. Greater emissions of other pollutants would result due to the increase in fuel combustion. It was also determined that the wet FGD system is less effective at controlling sulfuric acid mist, HAPs, total particulates, PM_{10}, as well as fine particulates.*
>
> *From a technical standpoint, the wet FGD system is less desirable than the dry FGD. The flue gas exiting the absorber from a wet FGD system is saturated with water and does still contain some SO_2. These gases are highly corrosive to any downstream equipment. It is possible to minimize the corrosion of the equipment by reheating the flue gases above the dewpoint temperatures and/or selecting construction materials and design conditions which will resist the corrosive conditions. However,*

> *these options do add cost to the system. Another aspect of the wet FGD system which is less desirable on a technical viewpoint is the wastewater produced, which is not a byproduct of the dry FGD system.*
>
> *When taking all of these aspects into consideration, the Air Program determined that the dry FGD system was a better option for the City Utilities project. As stated earlier, dry FGD systems have been selected as BACT for other recently proposed or permitted boilers burning PRB coal.*

Quoted in Nevada Response to EPA at 3, Exhibit 11.

Similarly, a dry FGD system was selected as BACT for the Dry Fork boiler burning PRB coal. The use of a dry scrubber system at the Dry Fork plant will have fewer economic, energy and environmental impacts than a wet scrubber system.

In addition, Basin has further refined its selection of dry scrubber technology. As explained further below, Basin will use a circulating dry scrubber for SO_2 control and not a spray dryer absorber as indicated in WDEQ's Permit Application Analysis.

Background

Based on information submitted in the Permit Application and supplemental submittals (the "BACT Analysis") Basin proposed dry scrubbing, designed as either a spray dryer absorber (SDA) or circulating dry scrubber (CDS), as BACT for SO_2 control, and Basin proposed an SO_2 BACT emission limit of 0.10 lb/MMBtu based on a 30-day rolling average. On February 5, 2007, WDEQ issued a Permit Application Analysis for the Dry Fork facility. The Permit Application Analysis included the agency's BACT analysis for each PSD pollutant. WDEQ concluded that dry FGD designed as an SDA control system represented BACT for SO_2 control.

Subsequently, on March 23, 2007, Basin submitted comments to WDEQ regarding the Permit Application Analysis and the proposed emission limits. Among other comments, Basin provided information clarifying its conclusions regarding SO_2 control technologies. Specifically Basin requested that WDEQ change references to "SDA" to "DFGD" and that DFGD refer to either an SDA or CDS control system. Basin's BACT analysis concluded that both SDA and CDS dry scrubbing systems were technically feasible and commercially available for the Dry Fork Station. In addition, Basin submitted a BACT analysis for its preferred DFGD technology of a circulating dry scrubber on June 11, 2007. A copy is attached as Exhibit 5. (Sargent & Lundy, Memorandum regarding SDA—CDS Comparison, June 8, 2007). The following draws, in part, on that analysis.

Dry Flue Gas Desulfurization

Dry scrubbing involves the introduction of dry or hydrated lime slurry into a reaction vessel where it reacts with SO_2 in the flue gas to form calcium sulfate and calcium sulfite solids. Dry scrubbing typically includes a separate lime preparation system and reaction vessel. Unlike wet FGD systems that produce a slurry by-product that is collected separately from the fly ash, *dry FGD systems produce a dry by-product that is removed with the fly ash in the particulate control equipment. Therefore, dry FGD systems must be located upstream of the particulate control device to remove the fly ash and reaction by-products.*

Various dry FGD systems have been designed for use with pulverized coal-fired boilers. The two primary options are spray dryer absorbers and circulating dry scrubbers.

Spray Dryer Absorber

The typical SDA uses a slurry of lime and water injected into one or more reaction tower to remove SO_2 from the combustion gases. The reaction towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry to produce a dry by-product. The process equipment associated with a spray dryer typically includes an alkaline storage tank, mixing and feed tanks, one or more reactant atomizers, spray chamber, particulate control device, and a recycle system. The recycle system collects solid reaction products and recycles them back to the spray dryer feed system to reduce sorbent consumption.

Circulating Dry Scrubber

A second type of dry scrubbing system is the circulating dry scrubber (CDS). A CDS system uses a circulating fluidized bed of dry hydrated lime reagent to remove SO_2 from the flue gas. Flue gas passes through a venturi at the base of a vertical reactor tower. Water is injected into the absorber at the throat of the venturi to humidify the flue gas. The humidified flue gas enters a fluidized bed of powdered hydrated lime and recycled by-produce where SO_2 is removed. Water used to humidify the flue gas evaporates in the absorber, cooling the flue gas from approximately 300 °F at the inlet to approximately 160 °F. Velocity in the absorber is maintained to sustain a fluidized bed of particles. Hydrated lime in the reaction vessel reacts with SO_2 to form calcium sulfite and calcium sulfate solids. Desulfurized flue gas passes out of the absorber, along with fly ash, reaction by-products, and unreacted lime to the unit's particulate control system (fabric filter baghouse).

Based on information available from equipment vendors, the CDS flue gas desulfurization system should be capable of achieving SO_2 removal efficiencies similar to those achieved with an SDA. In addition, the CDS offers the potential to achieve incrementally higher control efficiencies with increased reaction injection rates to address coal sulfur content variability, however, the ability to achieve higher control efficiencies has not been demonstrated on an on-going long-term basis.

BACT for SO_2

Based on its original BACT Analysis, Basin proposed "dry scrubbing (SDA or CDS) with a controlled SO_2 emission rate of 0.10 lb/MMBtu as BACT for Dry Fork Station." (See March 2006 Response at Attachment No. 1). The BACT Analysis concluded that a SO_2 emission limit of 0.10 lb/MMBtu (30-day rolling average) should be both technically and economically feasible, requiring BEPC to achieve control efficiencies in the range of 92% (based on an uncontrolled SO_2 emission rate of 1.21 lb/MMBtu). The proposed emission limit and control efficiency requirements should be achievable with either SDA or CDS control systems, including a reasonable operating margin for compliance.

Subsequently, WDEQ evaluated the control technologies and proposed the following permit limits:

- *0.08 lb/MMBtu (12-month rolling average)*
- *304.1 lb/hr (30-day rolling average, based on 0.08 lb/MMBtu x 3,801 MMBtu/hr heat input)*
- *380.1 lb/hr (3-hour block average, based on 0.10 lb/MMBtu x 3,801 MMBtu/hr heat input)*

In order to achieve the 12-month rolling average emission limit of 0.08 lb/MMBtu, Basin will need to achieve average control efficiencies in the range of 93.4% (based on an uncontrolled SO_2 emission rate of 1.21 lb/MMBtu). This control efficiency is very close to the technical limits of both the SDA and CDS control systems, and provides limited operating margin for compliance. Similarly, to achieve a 3-hour block average of 380.1 lb/hr, Basin will need to achieve removal efficiencies in the range of 92% (depending on the fuel sulfur content and boiler load). This short-term control efficiency requirement is also very close to the technical limits of the dry FGD control systems, an may be especially problematic with the SDA system design.

As discussed in the BACT Analysis, both dry FGD control systems will likely experience short-term spikes in the controlled SO_2 emission rate. Several process parameters can contribute to these short-term emission rates, however, with an SDA system one of the contributing factors would be the routine replacement of reactant injection nozzles. The atomizing nozzle assembly (either the duel-fluid feed lance assembly or the rotary atomizer assembly) is typically located in the SDA penthouse, and flange mounted to the roof of the absorber vessel. Overhead cranes or hoists located in the penthouse can be used to remove the nozzle assemblies from the absorber vessel for repair and maintenance. Because of the abrasive nature of the reactant slurry, nozzle assemblies must be removed and replaced on a routine basis. Depending on the design of the SDA system, one or more spare nozzle assemblies will be available for use. The nozzle assemblies may be changed without shutting down the SDA system, however, during that time period, the SDA may not be able to maintain maximum control efficiencies. CDS control systems do not have atomizing nozzles, which should result in less frequent short-term excursions.

A second important factor that can lead to short-term SO_2 excursions is the variability in the inlet SO_2 loading to the control system. As described in the Permit Application, the Dry Fork Station will be a mine-mouth facility and will fire coal from the adjacent Dry Fork Mine. Fuel characteristics, including heating value and sulfur content, are not uniform throughout the mine. As a mine-mouth facility, the Dry Fork Station will be required to fire coal delivered from the mine and will have limited time to respond to variability in the fuel characteristics. Based on the design of the CDS control system, including the fact that all of the boiler flue gas is directed through a fluidized bed of reactant, it was concluded that the CDS will respond more effectively to variations in fuel characteristics. In other words, the CDS system offers a better chance of complying with stringent SO_2 emission rates given the unique challenges at a mine-mouth plant.

Finally, potential balance-of-plant impacts were concluded to be potentially less significant with the CDS system compared to the SDA. The more stringent permit limits *proposed by WDEQ reduced the compliance/operating margin between the performance target of a dry FGD control system and the enforceable permit limit. Operating an SDA system so close to the design limits increases the potential for detrimental operating impacts such as wall wetting, scaling, plugging and detrimental impacts on the baghouse. Based on engineering judgment, potential operating impacts with the CDS design would potentially be less significant.*

Based on a thorough review of the technical, commercial, and economic issues associated with both dry FGD control systems, and given the need to achieve an average emission rate of 0.08 lb/MMBtu and short-term removal efficiencies in the range of 92%, Basin concluded that: (1) either dry FGD control system (SDA or CDS) could meet the proposed BACT emission limits; (2) the cost effectiveness of either dry FGD control system is essentially identical; and (3) the compliance margin between the performance target and the enforceable permit limit will be minimal with either dry FGD system. However, Basin also concluded that the CDS design offers the following advantages: (1) the CDS offers a better chance of complying with stringent SO_2 emission rates given the unique challenges at a mine-mouth plant with respect to variability in the fuel characteristics; (2) potential balance-of-plant impacts associated with operating either system so close to the performance target are potentially less significant with the CDS (i.e., the CDS should not experience wall wetting, scaling, plugging and the associated detrimental impacts on the baghouse); and (3) the CDS will not experience short-term emission spikes associated with routine atomizer changeouts and should be better suited to achieve stringent emission rates based on short-term averaging times. Therefore, Basin is proposing dry FGD, designed as a CDS, as BACT for SO_2 control for Dry Fork Station.

NPS Comment #5 (p. 4)

Other projects make more effective use of their dry scrubbing technology, with a 93% SO_2 control at Newmont Nevada, White Pines, and High Plains vs. 92.4% control at Dry Fork.

***Response**: The actual control efficiency at Dry Fork Station will be 93.4% SO_2 control, based on the 0.08 lb/MMBtu annual average emission limit (the 92.4% control cited in the comment is based on the original proposed SO_2 limit of 0.10 lb/MMBtu). This higher control efficiency is the same as the proposed control efficiency for the LS Power High Plains Plant (93.4%) and is better than the proposed control efficiencies at both Newmont Nevada (93.1%) and LS Power White Pines (93.2%). NPS Comments at Table 1.a. None of the other projects cited make more effective use of their dry scrubbing technology. Further, none of the other projects have been constructed and thus, none of them have demonstrated that they can meet their SO_2 permit limits in practice. A permit issuer may appropriately consider, as part of its BACT analysis, the extent to which available data in the record evidence the ability to consistently achieve certain emissions rates or control effectiveness of the selected technology or pollution control method. Newmont EAB Decision at 15. Since none of these plants are operational, there is no data showing the plants will achieve their reported control efficiencies. Further, permitting agencies have discretion in determining whether a particular control efficiency level is appropriate in determining BACT and in setting an appropriate emissions limit. Newmont EAB Decision at 42.*

The more critical information for addressing BACT and air quality and environmental impacts is the resulting emissions rate, not a control efficiency that may only reflect higher *uncontrolled emissions. The SO_2 BACT emission limit does not reflect the maximum degree of control that Basin's SO_2 controls will achieve at any given point in time; it reflects the lowest emission rate that Basin can consistently meet. See Newmont EAB Decision at 43 (discussing use of emissions rates rather than control efficiencies). Basin fully expects to achieve lower SO_2 emission rates during periods of operating its boiler, but understands from extensive discussions with boiler manufacturers and vendors that the limit in the WDEQ permit is the lowest limit that it can consistently achieve. Newmont EAB Decision at 18 (permit writers have discretion to set BACT levels that will allow permittees to consistently achieve compliance); Prairie State EAB Decision at 72–73.*

The BACT analysis requires that all pollution control technologies be ranked by their performance. But the best performing system would be based on the emission rate as judged by the analysis. There is no requirement to include a percent reduction in the permit limits established for a facility. Applying percent reductions for emissions based on the proposed percent reductions at other facilities that are not yet operational is not appropriate for demonstrating what is consistently achievable for the long term operation of the Dry Fork facility. Prairie State EAB Decision at 71 (discussing ability of permit issuer to take into account long-term data).

NPS Comment #6 (p. 5)

Wyoming must show why incremental costs at Dry Fork to achieve a 0.010 lb/MMBtu emission limit for PM_{10} are greater than at other projects (Sithe's Desert Rock and Toquop, and the Two Elk Expansion) with that proposed or permitted limit.

Response: *A detailed BACT analysis for PM is included in Attachment No. 3 to the March 2006 Response (Exhibit 3) and in the Permit Application at Section 5.2.6. While it is likely that Basin's actual PM_{10} emissions will be below 0.012 lb/MMBtu, and may even be as low as 0.010 lb/MMBtu, Basin needs a margin of safety in its permit limit to ensure consistent compliance with its permit limit. The Two Elk Expansion permit was finalized with a higher PM_{10} limit of 0.015 lb/MMBtu, than Basin's proposed limit.*

In addition, below a permit limit of approximately 0.012 lb/MMBtu, it is anticipated that fabric filter vendors would specify the use of specialty bags. Specialty bags represent a significant increase in the initial capital investment and a significant increase in the cost of replacement bags. Assuming specialty bags would be specified, the incremental cost effectiveness associated with reducing PM_{10} emissions from 0.012 to 0.011 lb/MMBtu is estimated to be approximately \$51,441/ton. And to further reduce PM_{10} emissions from 0.011 to 0.010 lb/MMBtu would be another \$10,000 for a total of \$61,441 for the incremental cost in reducing PM_{10} emissions from 0.012 to 0.010 lb/MMBtu. This incremental cost effectiveness is disproportionately high because of the relatively small increase in emission reductions (approximately 17 tpy) and the relatively large increase in initial capital and O&M costs associated with the specialty bags. This very high incremental cost would preclude specialty bags from consideration as BACT.

In addition to the economic impacts, there may be collateral environmental impacts associated with the membrane filters. The effectiveness of a bag filter increases as the *particulate cake builds on the fabric and within the filter material. In addition to increasing the filtering effectiveness, the alkaline filter cake captures SO_2, acid gases, and trace constituents including mercury. Once the pressure drop across the filter cake reaches a certain level, the bag is cleaned and the filtering/cake building process starts over. Membrane fabrics will release virtually all of the filter cake during the cleaning cycle, and may not retain a particulate cake within the fabric's interstitial space after cleaning. This characteristic of a membrane filter may inadvertently reduce the unit's overall control efficiency of acid gases and mercury. All recently permitted PC boilers identified by Basin have been permitted with fabric filters as BACT for PM_{10} control. The lowest filterable PM_{10} emission rate permitted as BACT was 0.012 lb/MMBtu at Comanche Unit 3 (Colorado) and Wygen Unit 2 (Wyoming). Neither unit has commenced operation or demonstrated the ability to achieve the proposed BACT emission limit on an on-going long-term basis. Several other facilities, including Roundup Units 1 and 2 (Montana) and Intermountain Unit 3 (Utah), have been permitted with a filterable PM_{10} emission rate of 0.015 lb/MMBtu. Basin was not able to obtain a vendor guarantee below 0.012 lb/MMBtu. Because Basin is proposing a control technology that results in the most stringent controlled emission rate, the use of fabric filters and a controlled PM_{10} emission rate of 0.012 lb/MMBtu should be considered BACT for the proposed boiler. March 2006 Response at 2 (Exhibit 3).*

Further, the Desert Rock and Toquop facilities have not been permitted or constructed and have not demonstrated that they can meet their BACT limits in practice. As stated in the recent Newmont EAB Decision:

> *[A] permit issuer may appropriately consider, as part of its BACT analysis, the extent to which available data in the record evidence the ability to consistently achieve certain emissions rates or control efficiencies of the selected technology or pollution control method. Accordingly, we hold that a permit issuer's rejection of a more stringent emissions limit based on the absence of data showing that the more stringent rate has been consistently achieved over time is not a per se violation of the BACT requirements.*

Newmont EAB Decision at 15. Since Desert Rock and Toquop are not yet operational, there is no data showing the plants will achieve their reported emissions limits.

In addition, Desert Rock's proposed PM_{10} limits (66.4 lb/hr (6-hr average), 0.010 lb/MMBtu (24-hr average)) have longer averaging times than Basin's PM_{10} limits. See Desert Rock Energy Center (AZP 04-01), Proposed Permit Conditions, available at http://www.epa.gov/region09/air/permit/desertrock/index.html (last visited 6/11/07). Basin's BACT limits are further justified because Basin proposes to meet the limits on a 3-hr basis instead of a 6-hr or 24-hr average, as is the case at Desert Rock. The Toquop permit application does not supply an averaging time for PM_{10}. See Toquop Energy Project, Class I-B Operating Permit to Construct Application, Appendix 10, p. 10-44, available at http://www.ndep.nv.gov/bapc/toq.html (last visited 6/11/07). However, the Toquop permit application, like the Basin permit application, determined that the lowest filterable PM_{10} emission rate designated as BACT for other recently permitted PC boilcers was 0.012 lb/MMBtu. Id. at 10-34.

Further, the EAB has held that "a permit writer is not required to set the emission limit at the most stringent emissions rate that has been demonstrated by a facility using similar emissions control technology." Prairie State EAB Decision at 72 (citing In re Kendall New Century Dev., 11 E.A.D. 40, 52 (EAB 2003)). Instead, permit writers retain discretion to set BACT levels that "do not necessarily reflect the highest possible control efficiencies but, rather, will allow permittees to achieve compliance on a consistent basis." Prairie State EAB Decision at 72 (citing In re Steel Dynamics, Inc., 9 E.A.D. 165, 188 (EAB 2000)); accord In re Three Mountain Power, L.L.C., 10 E.A.D. 39, 53 (EAB 2001)). As discussed in Basin's BACT analysis, a controlled PM_{10} emission rate of 0.012 lb/MMBtu is the most stringent emission rate that will allow Basin to achieve compliance on a consistent basis at the Dry Fork plant.

NPS Comment #7 (p. 5)

Proposed H_2SO_4 limit is higher than the wet scrubber proposed by Cash Creek and the dry scrubber proposed by Newmont; Wyoming should lower limit to reflect Newmont's limit.

Response: *As discussed in the response to EPA Comment # 1, air pollution control equipment vendors have not been willing to guarantee H_2SO_4 emission rates below approximately 2 ppmvd @ 3% O2 (approximately 0.005 lb/MMBtu depending on boiler design and performance) due to the detection limit and interference issues associated with EPA Test Method 8 used to demonstrate compliance. Therefore, to ensure that a guarantee can be obtained for the proposed emission rate, Basin proposed a controlled H_2SO_4 emission rate of 17.1 lb/hr (0.0045 lb/MMBtu or approximately 2 ppmvd @ 3% O2). See Exhibit 1, (June 2006 Response at Attachment 1).*

The H_2SO_4 emission rates proposed for both Cash Creek and Newmont are below the detection level for H_2SO_4 using EPA's current approved test method. Basin's vendors and BACT experts believe that the proposed limit for Dry Fork is the lowest limit that Basin can consistently achieve and demonstrate compliance with. Although Basin is confident that the combination of DFGD+FF will provide the most effective H_2SO_4 control, Basin is not required to propose an emission limit below the practical detection limit of the compliance test method (see response to EPA Comment #21). Therefore, an emission rate of 0.0045 lb/MMBtu (approximately 1.8 ppmvd @ 3% O2) represents an appropriate BACT rate for H_2SO_4.

See response to EPA Comment #1 for a detailed discussion of Newmont's limit. Cash Creek is a proposed IGCC plant that utilizes different technology than Dry Creek Station. See EPA, Recent PSD Permit Applications received by Region 4, at http://www.epa.gov/region04/air/permits/PSDapplications.htm (last visited 5/23/07). There is no operating experience at any IGCC plant demonstrating that the H_2SO_4 limit proposed for Cash Creek can actually be met. Since the Dry Fork Station utilizes different technology, this should be taken into consideration in determining a BACT limit. See responses to comments regarding Basin's decision not to use IGCC technology for further information. A permit issuer may appropriately consider, as part of its BACT analysis, the extent to which available data in the record evidence the ability to consistently achieve certain emissions rates or control effectiveness of the selected technology or pollution control method. Newmont EAB Decision at 15. Further, it may well be that the H_2SO_4 emissions at the Dry Fork plant will be at the same *level as the currently proposed limit at Cash Creek; however, for all of the reasons already described above, the compliance test method would likely not be able to demonstrate this.*

NPS Comment #8 (p. 5)

Dry Fork facility should have lower Mercury limit.

Response: *The Dry Fork Station will be subject to the NSPS for Mercury that was promulgated as part of the Clean Air Mercury Rule (CAMR). The CAMR became effective on July 18, 2005. 70 Fed. Reg. 28605, 28606 (May 18, 2005). In 2006, EPA revised the NSPS for Mercury based on Best Demonstrated Technology (BDT), type of coal combusted and regional precipitation levels. 71 Fed. Reg. 33388-33402 (June 9, 2006). EPA indicated that dry FGD represents BDT for areas receiving less that 25 inches mean annual precipitation. The revised NSPS for new units burning sub-bituminous coal and utilizing dry FGD systems is 97×10^{-6} lb/MW-hr. The emission control technologies utilized for this project, including dry scrubbing for SO_2 control and a fabric filter for control of particulates, represent BDT for control of mercury for this type of unit according to the CAMR. Basin will comply with the mercury emissions established under the CAMR.*

While a BACT analysis for mercury is not required on a federal level, Basin recognizes the WDEQ authority to request this review. As a result, Basin attempted to perform a BACT analysis for mercury as detailed in Exhibit 12 (Response to WDEQ's Completeness Review Dated May 3, 2006 (July 12, 2006) ("July 12, 2006 Response")) at 1 – 5. However, for the Dry Fork Station, a true BACT analysis is not possible for mercury for the following reasons:

- *Control technologies for mercury are still in the developmental stage, resulting in only limited information regarding possible alternatives and potential control efficiencies.*
- *A top-down analysis with cost estimates is not possible with current incomplete technology alternatives and cost information.*
- *Commercially available mercury control systems and associated vendor guarantees are very limited to date. Activated Carbon sorbent injection systems have been proposed and designed by a few vendors but other control technologies are at the planning and demonstration stages.*

After review of several recent coal fired unit permits and the present status of current mercury removal technologies, there remains a significant level of uncertainty regarding establishing an appropriate permit limit for mercury emissions. The three major areas of concern are:

1. *Unknown effects from numerous unit operating parameters on mercury capture – mercury removal pilot and demonstration projects conducted to date have shown that significant questions remain regarding how changing operating conditions can impact mercury emissions.*
2. *Uncertainty regarding future coal mercury levels - Any mercury permit limitation must provide the ability to meet the emissions criteria under the entire range of mercury in the fuel, and at a reasonable cost.*

3. *Current status of Continuous Emissions Monitors (CEM) – Commercially available CEM systems for mercury have just started to come on the market. The accuracy of the current CEMs at very low mercury levels is questionable.*

Given the current stage of mercury control technology, the inherent concerns with potential unit operating uncertainties, and the status of CEMs, Basin proposes the following course of action:

1. *The current CAMR emissions limit of 97 X 10^{-6} lb/MWh on an output basis 12 month rolling average should be maintained as a permit limitation. 71 Fed. Reg. 33388-33402 (June 9, 2006).*
2. *Basin will install a mercury control system at startup with a target emission rate of 20 x 10-6 MW/hr, 12 month rolling average.*
3. *Basin will perform a Mercury Optimization Study at the Dry Fork Station. This testing program would begin approximately July 2011 (approximately six months after unit start-up and allowing for shakedown of the unit), and would continue for one year.*
4. *The testing program will include a review of the following potential mercury technology options:*
   a) *Sorbent Injection Technologies*
   b) *Sorbent Enhancement Additives*
   c) *Coal Pretreatment Processes*
   d) *Mercury Oxidation Technologies*
5. *Results from the testing program would be provided to the WDEQ, and implemented on Dry Fork Station as appropriate. Basin and WDEQ will jointly determine whether permit modifications are necessary, including whether a lower mercury limit will be applied to the Dry Fork plant following the results of the testing program.*

NPS Comment #9 (p. 5)

Basin's reliance on mercury control as an added benefit of dry scrubbing technology is not convincing when the plant's mercury limit is higher than plants with wet scrubbers.

Response: *Basin reviewed the relative control effectiveness for mercury control as reported by Nevada in its review of the draft permit for the Newmont Nevada - TS Power Plant using the recent EPA Information Collection Request (ICR) data base, for collecting data on mercury emissions. Nevada Response to NPS Comments, Draft Permit for Newmont Nevada – TS Power Plant, at 17, attached as Exhibit 13. The relative control effectiveness of the dry scrubber and wet scrubber systems were compared, using the raw data, for plants with less than 200 ppmw mercury in the coal supply similar to PRB coal. Three plants with a wet scrubber met this criteria, and the average control effectiveness was 9.2 percent. Six units with a fabric filter and dry scrubber were also evaluated, and their average control effectiveness was 23.8 percent. The data suggest that the fabric filter and dry scrubber system enhances the control of mercury emissions better than a wet scrubber, and thereby improves mercury removal from coal-fired power plant flue gases. Further, the fabric filter is located downstream of a dry scrubber and* *provides co-benefits for mercury control which can be more easily and economically collected with the combination of partial condensation in the dry scrubber followed by capture of particulate mercury in the fabric filter.*

The emission limit for mercury at Dry Fork is based on the current CAMR emissions limit of 97 X 10^{-6} lb/MWh on an output basis 12 month rolling average. However, Basin will have a mercury control system in place at startup, and that system will have a target goal of achieving an emission rate of 20 x 10^{-6} MW/hr. See response to NPS Comment # 8. If the target rate is achieved, then the Dry Fork plant's mercury emissions will be significantly lower because of the dry scrubber and the additional mercury control system.

NPS Comment #10 (p. 6)

WDEQ should include a permit limit on NO_x consistent with the 24-hour emissions modeled in the visibility analysis. Without such a limit, there is no way to insure the 24-hour emissions and consequent impacts on visibility will not exceed the rate modeled.

Response: *The modeled NO_x emission rate was 266 lb/hr, 24-hour average, and the permit limit is 190 lb/hr, 30-day average. In order to comply with the 30-day limit, Dry Fork will need to comply with the 24-hour modeled rate. Sargent & Lundy, engineering consultants to Basin Electric on the Dry Fork project, evaluated the issue of whether compliance with the 30-day average would ensure 24-hour emissions less than 266 lb/hr, and concluded that it would. Sargent & Lundy, Memorandum regarding Proposed NO_x Emission Limits, June 16, 2007, (S&L NO_x Memo) Exhibit 14. This conclusion is based on empirical data showing the relationship between 24-hour and 30-day average emission rates at three coal-fired units similar to Dry Fork, and the lack of any practical operating scenarios in which Dry Fork could emit more than 266 lb/hr of NO_x and still comply with the permit limit of 190 lb/hr 30-day average. Details supporting this conclusion are presented in the discussion below, which draws on the S&L NO_x Memo. There is no need for a 24-hour NO_x limit because compliance with the 30-day limit will ensure that 24-hour emissions will be consistent with the emissions modeled for visibility impacts.*

Potential NO_x emission rates are used in two distinct modeling assessments: (1) PSD impact modeling (including Class II significant impact level, PSD increment, and NAAQS); and (2) CALPUFF visibility impact modeling. PSD impacts are assessed on an annual average NO_x emission rate, while CALPUFF modeling is based on a 24-hour average emission rate. Emission rates that correlate to the appropriate averaging times were developed for use in each of the models based on engineering judgment, anticipated vendor guarantees, and actual emissions data available from existing units.

To establish the appropriate NO_x emission rate for each averaging time, Basin reviewed actual emissions data from three existing pulverized coal-fired units equipped with SCR: Hawthorne Unit 5, Parish Unit 5, and Baldwin Unit 2. All three units are subbituminous-fired boilers equipped with SCR for NO_x control, and currently achieve among the lowest annual NO_x emissions of any coal-fired electricity utility steam-generating unit.

Hourly NO_x emission rates from a coal-fired boiler equipped with SCR will fluctuate around an operating point depending on several boiler and control system operating variables. Operating variables that influence the performance of the SCR system include the volume, age, and surface area of the catalyst; boiler NO_x emission rate, flue gas flow, flue gas temperature, presence of trace contaminants in the flue gas, ammonia (ammonia) injection rate, flue gas and ammonia mixing, and catalyst activity. As with all emission control systems, the controlled NO_x emission rate will fluctuate as these process variables constantly change.

Short-term spikes in the controlled NO_x emission rate can be dampened by averaging NO_x emissions over a given period of time (e.g., 24-hour average, 30-day average, etc.). Figures 1, 2, and 3 show the hourly NO_x emission rates and the calculated rolling 24-hour and 30-day averages achieved in practice at each facility during 2005. Emissions data for each source were obtained from EPA's Clean Air Markets database available at: http://cfpub.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard.

The relationship between 24-hour and 30-day average emission rates can be quantified by evaluating the variability in controlled NO_x emission rates for each averaging time. To do this, Basin calculated the rolling 24-hour and 30-day averages for each facility and calculated the standard deviation associated with each averaging time. Tables 2 and 3 summarize the NO_x emissions data reported by each facility between January 1, 2005 and December 31, 2005. Table 2 includes an evaluation of the variability of the controlled NO_x emission rate (lb/MMBtu) as a function of averaging time. Table 3 evaluates the same data on a mass emission rate (i.e., lb/hr) for each averaging time.

Data summarized in Tables 2 and 3 indicate that shorter averaging periods show greater variability in the controlled NO_x emission rate. Therefore, as expected, the average emission rates achieved on a 24-hour period are higher than the corresponding emission rates achieved on a 30-day period. An evaluation of emissions data from the three existing units suggests that the 24-hour average emission rate (on a lb/MMBtu heat input basis) will range from about 18% to about 30% above the corresponding lb/MMBtu 30-day average. However, on a lb/hr basis, the 24-hour average emission rate is typically within approximately 10% of the 30-day average emission rate. This is probably true because short-term excursions in the NO_x emission rate (lb/MMBtu) are often associated with boiler load changes. Load changes affect several boiler operating variables, including flue gas flow rates and temperatures, requiring some time to tune the ammonia injection rate and ensure adequate flue gas/ammonia mixing.

Table 2
NO_x Emission Rates (lb/MMBtu) and Variability

	Maximum Reported Heat Input	NO_x Emissions[1] Annual Average NO_x Emission Rate	NO_x Emissions[1] Average NO_x Emission Rate at 95% Confidence Level[2]	
	MMBtu/hr	(lb/MMBtu)	(lb/hr)	(%)
Hawthorn Unit 5	7,109	0.073	0.091 (24-hour) 0.076 (30-day)	19.7%
Parish Unit 5	7,613	0.043	0.057 (24-hour) 0.048 (30-day)	18.6%
Baldwin Unit 2	6,632	0.065	0.127 (24-hour) 0.089 (30-day)	42.7%

(1) Based on 2005 Emissions Data

(2) NO_x emissions data for the 24-hour and 30-day rolling averages were evaluated for normal distribution, and variation in the data was evaluated by calculating the standard deviation for each averaging period. The 95% confidence level for each averaging period was calculated based on the average emission rate plus two standard deviations.

Table 3
NO_x Emission Rates (lb/hr) and Variability

		NO_x Emissions[1] Maximum Heat Input x Annual Average NO_x Emission Rate	NO_x Emissions[1] Average NO_x Emission Rate at 95% Confidence Level[2]	
	MMBtu/hr	(lb/hr)	(lb/hr)	(%)
Hawthorn Unit 5	7,109	519.0	532.3 (24-hour) 488.5 (30-day)	9.0%
Parish Unit 5	7,613	319.8	334.2 (24-hour) 300.4 (30-day)	11.3%
Baldwin Unit 2	6,632	431.1	474.0 (24-hour) 454.4 (30-day)	4.3%

(1) Based on 2005 Emissions Data

(2) NO_x emissions data for the 24-hour and 30-day rolling averages were evaluated for normal distribution, and variation in the data was evaluated by calculating the standard deviation for each averaging period. The 95% confidence level for each averaging period was calculated based on the average emission rate plus two standard deviations.

Figure 4 compares hourly boiler heat input changes (± lb/MMBtu) to the hourly NO_x emission rate (lb/MMBtu) for Baldwin Unit 2 between March 5 and March 14, 2005 (These dates were chosen because data showed high short-term NO_x emission rates). It can be seen that short-term spikes in the lb/MMBtu NO_x emission rate are often associated with relatively large drops in the boiler heat input. Therefore, even though the NO_x emission rate increases on a lb/MMBtu basis, there is no corresponding increase in the hourly mass NO_x emissions.

It is anticipated that the Dry Fork boiler will operate much the same, with respect to variability, as the best controlled similar sources currently in operation. That is, the boiler will likely experience short-term NO_x excursions associated with normal changes in boiler and control system operation. The draft permit requires Basin to achieve controlled NO_x emission rates of 0.05 lb/MMBtu (annual average) and 190.1 lb/hr (30-day average). As discussed in response to Issue No. 1, this combination of emission limits will required Basin to respond quickly to short-term excursions and limit the duration of such excursions.

Based on an evaluation of the variability in controlled NO_x emissions at existing sources equipped with SCR control systems, the 24-hour average NO_x mass emission rate would expected to be approximately 10% higher than the corresponding 30-day rate. Based on a 30-day average emission rate of 190.1 lb/hr, 24-hour average emissions from the Dry Fork boiler will typically be below approximately 210 lb/hr. For impact modeling Basin used short-term NO_x emission rates as high as 266 lb/hr (approximately 40% above the 30-day average) to demonstrate that potential short-term emissions will not cause or contribute to adverse impacts to visibility at the Class I areas.

Compliance with the proposed permit limits (0.05 lb/MMBtu annual average, 190.1 lb/hr 30-day average, and 1.0 lb/MWh-gross 30-day average) will ensure that 24-hour emissions (lb/hr) will not exceed emission rates used in the impact modeling. There are no practical operating scenarios in which Basin could emit excess NO_x emissions for a 24-hour period while complying with the permit limit of 190.1 lb/hr (30-day average). Although short-term NO_x emissions may fluctuate, compliance with the proposed permit limits will require Basin to respond quickly to short-term NO_x excursions and limit the duration of any such excursions.

Figure 1
Hawthorne Unit 5 – Hourly NO_x Emission Rates

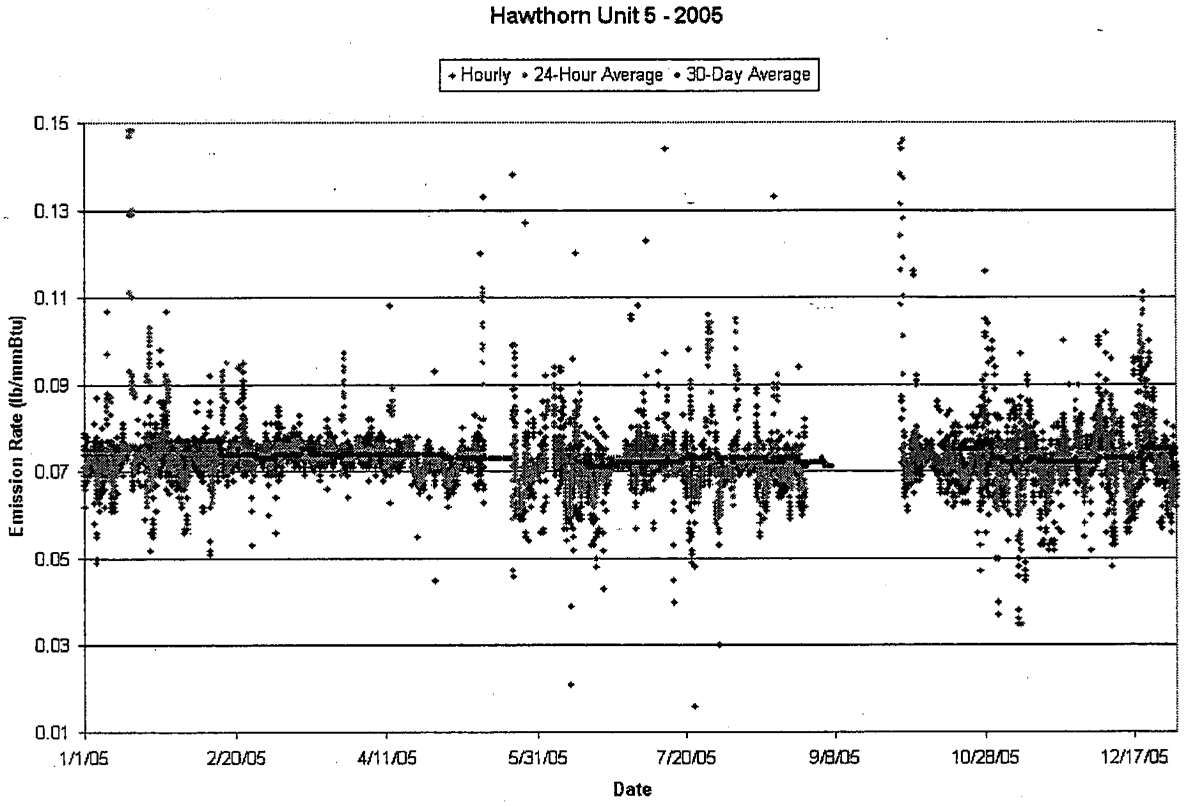


Figure 2
Parish Unit 5 – Hourly NO_x Emissions

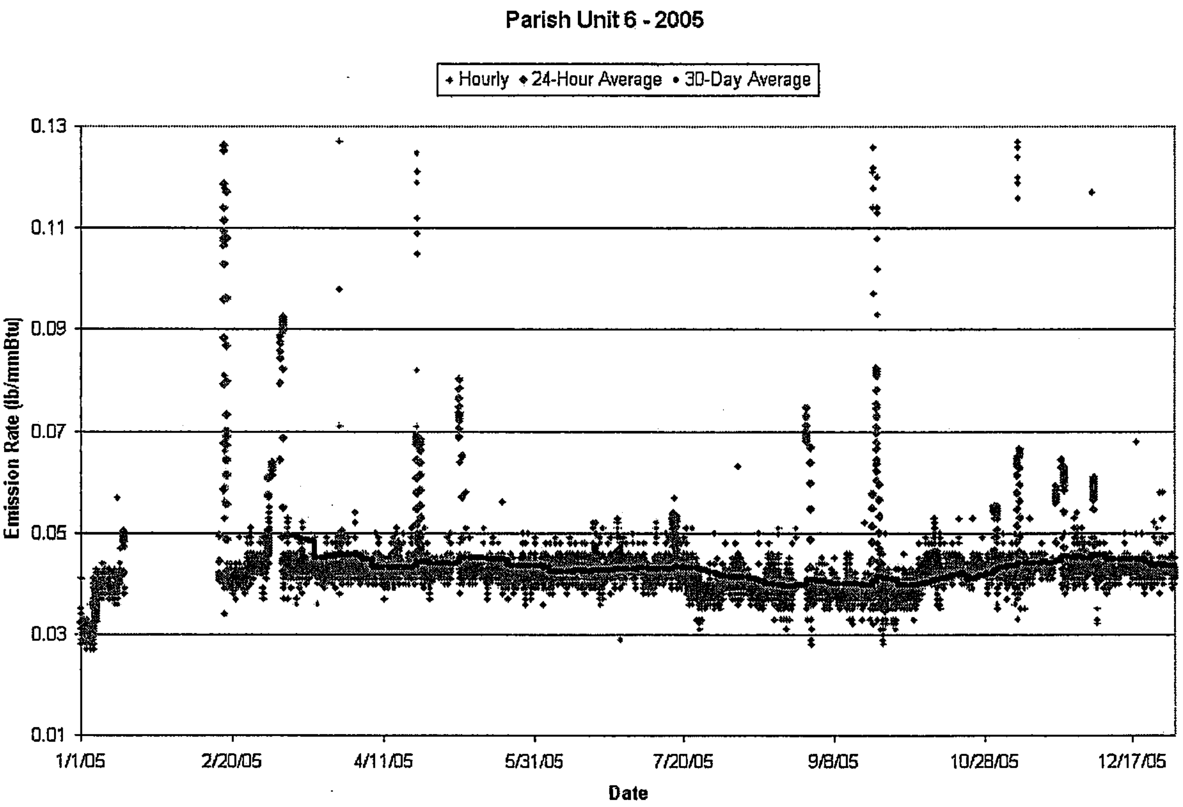


Figure 3
Baldwin Unit 2 – Hourly NO_x Emissions

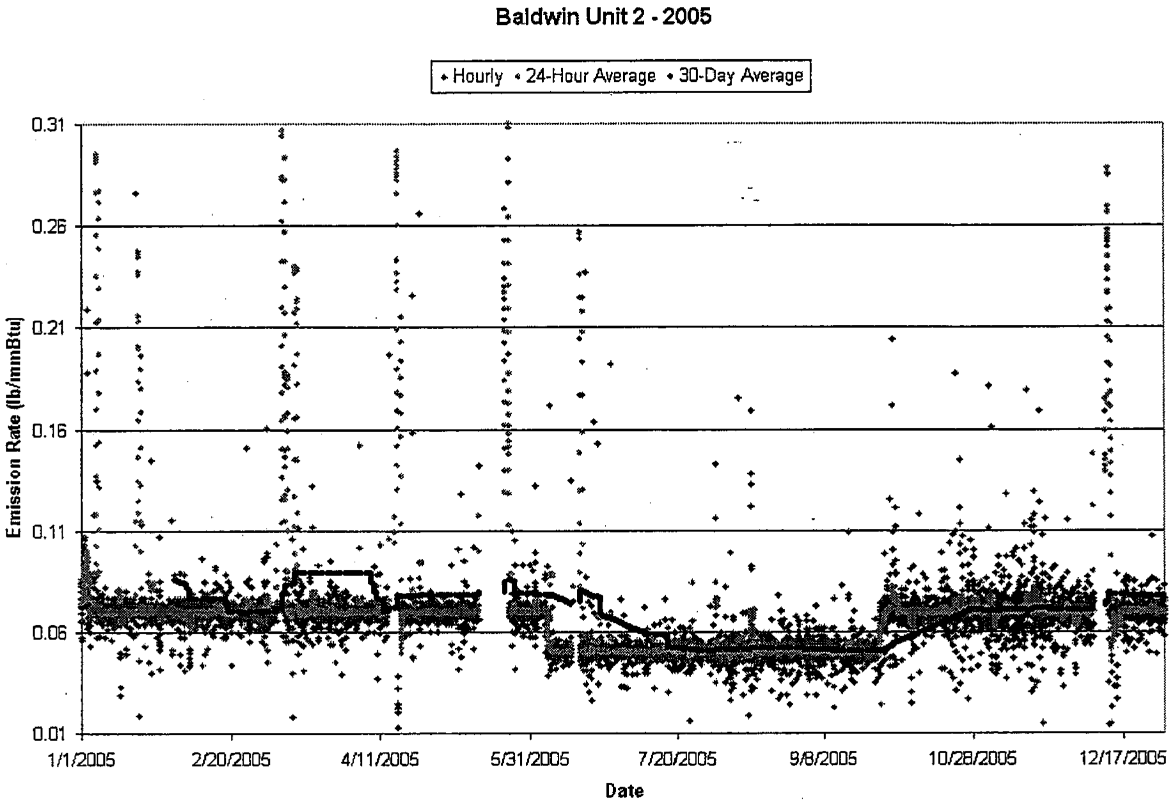
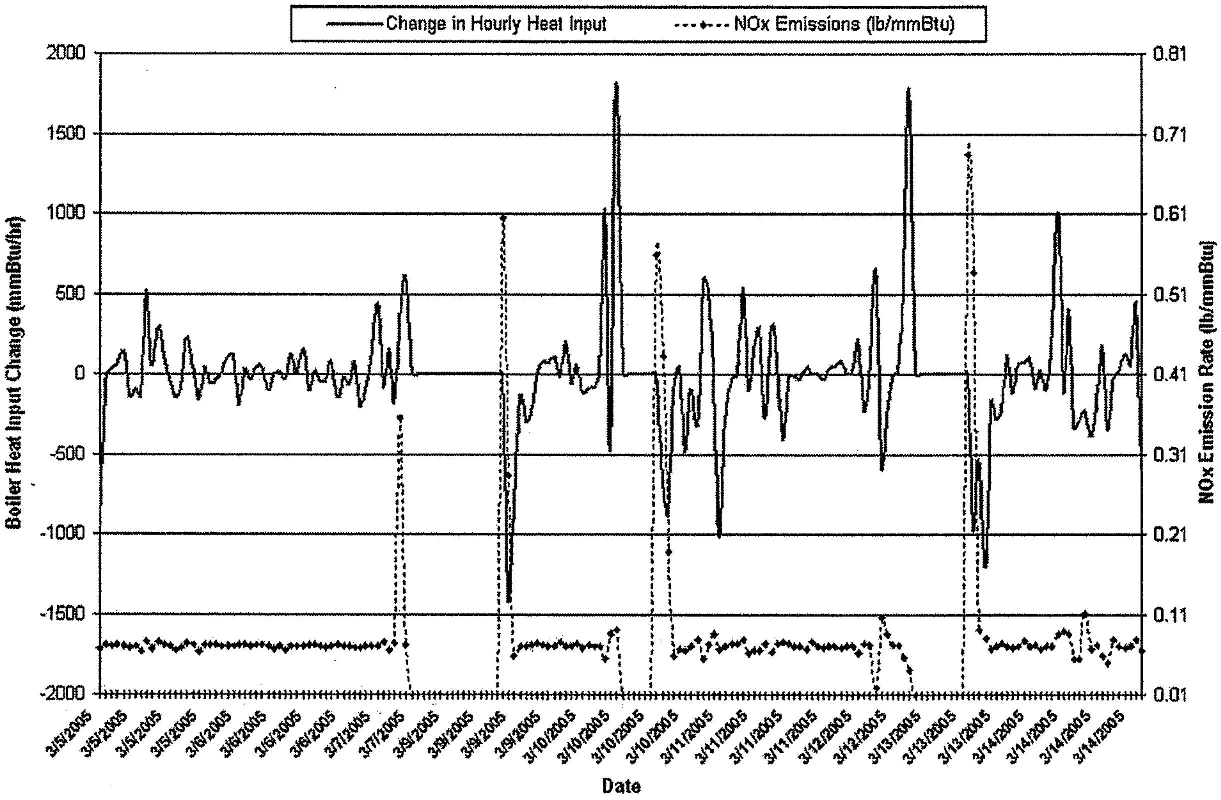


Figure 4
Parish Unit 5 – Boiler Load Changes vs. Hourly NO_x Emission Rates



The Environmental Appeals Board, in <u>*In re Prairie State Generating Station*</u>*, held that it was acceptable for the Illinois EPA to model visibility impacts using 30-day average permit limits for SO2 and NOx, rather than 24-hour limits, where the agency explained it would not expect short-term excursions at higher emission rates to have a significantly greater impact on visibility than the 30-day rates that were modeled, based on information in the record. Prairie State EAB Decision at 155-159. Illinois EPA noted that "[w]hile the models may be conservative, they should not be excessively conservative." Id. at 159. In this case Sargent & Lundy has provided a reliable analysis demonstrating that compliance with the permit will protect 24-hour visibility impacts. In fact, the modeling for Dry Fork was more conservative than the modeling approved in Prairie State—in that case the modeled emission rate was the 30-day average rate, whereas for Dry Fork the modeled* NO_x *rate was 40% higher than the 30-day emission rate.*

Finally, the modeling rules "vest considerable discretion in the permitting authority's judgment in selecting the appropriate modeling protocols, including the modeled emission rate" Id. at 160. Thus, the lack of a 24-hour NO_x *limit does not constitute a flaw in the proposed permit, or a ground for the NPS to object to the permit. There is no basis to conclude that visibility will not be adequately protected.*

NPS Comment #11 (p. 12)

WDEQ should include a permit limit on total PM_{10} consistent with the 24-hour emissions modeled in the increment and visibility analyses. The limit on total PM_{10} should be federally enforceable.

Response: *The Permit Application and the June 2006 Response submitted by Basin for Dry Fork Station included all the information required in a PSD permit application, including a BACT analysis and impact modeling. A BACT analysis was prepared for PM_{10}. Based on the BACT analysis, Basin proposed PM_{10} permit limits (filterable only) of 0.012 lb/MMBtu.*

The filterable PM_{10} (FPM_{10}) emission limit proposed in the Permit Application was based on a comprehensive review of available control technologies, anticipated vendor guarantees, and permit limits included in other recently issued PSD permits for coal-fired boilers. See response to NPS Comment #6 for more information on the PM_{10} BACT analysis. The June 2006 Response, at 3-8, explained the derivation of the condensable PM10 emissions that were input to the model, but due to lack of sufficient data to support an enforceable limit on condensable PM_{10}, Basin Electric proposed reliance on emission control technologies and compliance with the proposed BACT limit for H_2SO_4 in lieu of a imposing permit limits on condensable PM_{10} (CPM_{10}). The following draws on the June 2006 Response.

Basin agrees with the WDEQ's statement regarding the uncertainty in the quantification of condensable particulate emissions from coal-fired boilers. June 2006 Response, Exhibit 1, at Comment #3 ("The Division recognizes that there is a great deal of uncertainty in the quantification of condensable particulate emissions from coal-fired boilers . . . ."). PM_{10} emissions from coal-fired boilers have historically been measured and reported as FPM_{10}, and there is limited information characterizing CPM_{10} emissions from coal-fired boilders. In the past, compliance with particulate matter emission limits has been demonstrated using reference methods that involve filtration at 250 °F (EPA Method 5) or at actual stack temperatures (EPA Method 17). For example, compliance with the federal PM new source performance standard (NSPS) for electric utility steam generating units must be demonstrated using Method 5 at facilities without wet FGD systems and Method 5B after wet FGD systems (see, 40 C.F.R. 40.48a(b)). Both methods measure FPM.

With the change of the federal ambient air quality standard for particulate matter from total particulate to PM_{10}, EPA promulgated a series of reference methods to measure PM_{10} emissions from stationary sources. See Pjetraj, M., "Condensable Particulate Matter – Regulatory History and Proposed Policy", North Carolina Department of Air Quality (Jan. 27, 1998). These included Methods 201 and 201A for FPM_{10}, and Method 202 for CPM_{10}. These methods do not apply to any federal emissions limits and have not been incorporated into the federal NSPS. However, some recently issued PSD permits for new coal-fired units have included PM_{10} emission limits including both filterable and condensable particulates.

Sulfate (SO_4) compounds (e.g., sulfuric acid (H_2SO_4) mist) are the most widely recognized form of CPM emitted by combustion sources. See Corio, L.A., Sherwell, J., "In-Stack Condensable Particulate Matter Measurements and Issues", Journal of the Air & Waste ~~*Management Associate, vol. 50 (Feb. 2000), page 207. Sulfuric acid formed in the boiler and*~~

subsequent emission control systems (e.g., SCR and FGD) has a vapor pressure sufficiently low to condense at ambient conditions.

Beyond the H_2SO_4 component, there are limited analytical data characterizing CPM from coal-fired boilers. Other inorganic species will contribute to CPM emissions, including ammonium sulfate, other acid gases, and trace volatile metals. For example, ammonium sulfate ($(NH_4)_2SO_4$) will be formed when SO_3 in the flue gas reacts with free ammonia from the SCR control system. Trace levels of chlorine and fluorine in the coal will convert to HCl and HF gas during the combustion process, and may be captured as condensable particulates. Organic species in the flue gas may also exist as vapors at stack temperatures but condense to liquid or solid aerosols at ambient temperatures. Because pulverized coal-fired boilers are typically operated with essentially complete combustion, condensable organic emissions should be very low. EPA-sponsored evaluations of test Method 202 show that the inorganic constituents typically account for approximately 90 to 95% of the total condensable PM, with sulfate compounds, primarily H_2SO_4, accounting for most of the inorganic condensable emissions. Method Development and Evaluation of Draft Protocol for Measurement of Condensable Particulate Emissions; EPA, Research Triangle Park, NC, 1990.

EPA's Compilation of Air Pollution Emission Factors (AP-42) includes an emission factor for CPM from pulverized coal-fired boilers equipped with FGD control (AP-42 Table 1.1-5). However, the emission factor (0.02 lb/mmBtu total CPM) does not distinguish between the inorganic and organic fractions, and has an emission factor rating of "E". An emission factor rating of "E" indicates that the factor was developed from a small number of facilities, and that there may be reason to suspect that the facilities tested do not represent a random sample of the industry.

Because there is limited information from existing sources characterizing CPM emissions, and because the AP-42 emission factor for CPM from pulverized coal-fired boilers has an "E" rating, emission calculations are typically used to estimate CPM emissions from a specific source. CPM_{10} emission limits proposed in the Permit Application were estimated using site-specific coal characteristics, boiler operating conditions, and assumed emission control efficiencies. A summary of the CPM_{10} constituents, and a description of the methodology used to calculate each emission rate, is provided in the June 2006 Response at Table 2, Exhibit 1.

In addition to the limitations associated with calculating CPM emissions, stack testing methodologies used to measure H_2SO_4 and CPM_{10} (Methods 8 and 202, respectively) have proven to be problematic at coal-fired boilers. For example, interfering agents with Method 8 include fluorides and free ammonia. Method 8 states that if "any of these interfering agents is present . . . alternative methods, subject to the approval of the Administrator, are required." Because of the difficulties associated with demonstrating compliance with low H_2SO_4 emission rates, equipment vendors have not been willing to guarantee H_2SO_4 emissions below approximately 2 ppmvd @ 3% O_2. Based on information from equipment vendors, an emission rate of 2 ppmvd @ 3% O_2 (approximately 0.005 lb/mmBtu), represents the practical analytical detection limit of Method 8 on a coal-fired boiler.

Likewise, Method 202 has been shown to have a false positive bias when used on sources with SO_2 and ammonia in the flue gas, such as coal-fired boilers. See Corio, L.A., Sherwell, J., *"In-Stack Condensable Particulate Matter Measurements and Issues", Journal of Air & Waste Management Association, 50:207-218 (Feb. 2000). In Method 202, flue gas is bubbled through water-filled impingers located downstream of the filters used to capture filterable particulates. The contents of the impingers are evaporated and the residue is weighed to determine condensable particulate emissions. The basic problem involved in using Method 202 is that the method by which condensable species are collected in the impingers differs from the method by which condensable species coalesce into particles in the stack plume. For example, gaseous species in the flue gas that would not condense in the atmosphere (e.g., SO_2 and ammonia) may be collected in the impingers and converted to particulate species in the sampling train.*

As an example of this phenomenon, during sampling, a portion of the SO_2 in the sample gas (which is not a condensable species) will be dissolved in the impinger water. In the impinger sample, test data have shown that a portion of this SO_2 will oxidize to sulfate ion ($SO_4^{=}$) which will form sulfuric acid and be indistinguishable from true condensable particulates. Similarly, when both SO_2 and ammonia are in the gas stream, they will both dissolve in the impingers, and have been shown to react to form either ammonium sulfate or ammonium bisulfate, which tend to oxidize to ammonium sulfate ($(NH_4)_2SO_4$) and ammonium bisulfate ($(NH_4)HSO_4$) during sample storage and handling. Gaseous SO_2 and ammonia are not condensable species, however, ammonium sulfate and ammonium bisulfate will be measured as condensable particulates.

Because of the limited data from existing plants and limitations associated with Method 202, equipment vendors have not provided guarantees for stringent CPM emission limits. On one recent project (subbituminous-fired PC equipped with dry FGD) the most aggressive guaranteed emission rate available for total PM_{10} (FPM and CPM) was 0.025 lb/mmBtu, conditioned upon including modifications to the CPM compliance test method. Based on recent conversations with equipment vendors, it is anticipated that the most aggressive total PM_{10} (FPM and CPM) emission limit available for the proposed Dry Fork unit will be in the range of 0.020 to 0.025 lb/mmBtu.

Finally, although calculations can be used to predict CPM_{10} emissions, there is very limited information from existing coal-fired plants characterizing actual CPM emissions that can be used to check the veracity of the emission calculations. Without sufficient data from existing plants, it is not practical to establish an enforceable CPM BACT emission limit. Therefore, Basin has included the CPM emission rates for emission inventory purposes only, and not as an enforceable BACT emission limit. Basin is proposing emission control technologies, and compliance with the BACT emission limit for H_2SO_4 in lieu of a permit limit for CPM_{10}. H_2SO_4 is the most widely recognized form of CPM emitted by combustion sources, and control technologies designed to minimize sulfuric acid mist emissions will also minimize inorganic CPM, including other acid gases and ammonium sulfate.

Here, the emission limit on H_2SO_4 (and the control provided by the CDS) will act as a surrogate for assessing ongoing PM condensable emissions since H_2SO_4 comprises the majority of the condensable PM emissions. Similarly, the H_2SO_4 limit, in conjunction with the PM_{10} filterable limit, will ensure that emissions remain at or below the inputs used in the modeling.

Consistent with Basin's approach to CPM emission rates, the EAB recently upheld the Nevada Division of Environmental Protection's (NDEP) decision to issue a PSD permit without *including a specific CPM BACT emission limit. Newmont EAB Decision at 53–55. The PSD permit issued by NDEP for a new coal-fired boiler included a BACT emission limit for FPM, but did not include a BACT emission limit for CPM. During the permit review process, NDEP concluded that "BACT is typically set for the filterable fraction of PM/PM_{10} only, as no technology has been identified . . . to control condensable PM/PM_{10} emissions from coal-fired boilers and thus it would be technically impossible to establish BACT limits for condensables in circumstances such as these." The EAB upheld NDEP's decision to exclude a CPM BACT emission limit citing several PSD cases holding "[a]lthough BACT is defined as an 'emission limitation,' it is also, as its name implies, keyed to a specific control technology." Newmont EAB Decision at 54 (citing In re Hibbing Taconite Co., 2 E.A.D. 838, 844 (EAB 1989)). Similarly, because of the technical difficulties in controlling and establishing BACT limits for condensables at Dry Fork, WDEQ's decision to exclude a CPM BACT emission limit at Dry Fork is appropriate and consistent with past EAB decisions.*

Finally, the permit for Dry Fork requires testing for condensables, and the Permit Application Analysis states that if test results show condensables are higher than what was modeled, WDEQ will assess the need for further modeling. Thus, condensables will be tested and controlled by WDEQ if necessary.

NPS Comment #12 (p.6) (EPA # 8)

WDEQ should require CEMS to monitor filterable particulate matter.

Response: *See Response to EPA Comment # 8.*

NPS Comment #13 (p. 7-9)

The results of modeling for Dry Fork impacts on visibility in Wind Cave and Badlands National Parks in South Dakota, both Class I Areas, indicate impacts are significant and therefore there is a need for cumulative analysis of visibility impacts.

Response: *Under the PSD rules, Federal Land Mangers (FLMs), including the NPS, have a responsibility to protect the air quality related values (including visibility) in Class I Areas and to consider whether a proposed new source would have an adverse impact on such values. 40 C.F.R. § 51.166(p). If an FLM demonstrates a source would have an adverse impact, and if the state permitting authority agrees, a permit will not be issued. Id.; WAQS&R, Chap. 6, § 4(b)(vi). An adverse impact on visibility is defined as visibility impairment which interferes with the management, protection, preservation or enjoyment of the visitor's experience, taking into account the geographic extent, intensity, duration, frequency, and time of visibility impairment and how these relate to the times of visitor use and of natural conditions that reduce visibility. 40 C.F.R .§ 51.301; WAQS&R Chap. 9, § 2(c). Visibility impairment means any humanly perceptible change in visibility from that which would have existed under natural conditions. Id. The NPS has not alleged that Dry Fork would have an adverse impact on Air Quality-Related Values (AQRVs), but argues that the modeling for Dry Fork indicates that cumulative modeling should be done to assess the potential for adverse impacts. NPS at 8.*

Cumulative Modeling Is Not Authorized by Statute or Regulation

Basin Electric appreciates and respects the importance of the responsibility the FLMs have to protect visibility in Class I areas, and supports their ongoing efforts to carry out that obligation. However, despite the NPS'request, cumulative modeling is not authorized under the PSD rules. Unlike the broader scope of the Regional Haze Rule, which requires states to develop plans to reduce Class I visibility impacts from all sources, under the PSD rules the only issue for the FLM is whether a proposed new source itself would have an adverse impact on visibility. 40 C.F.R. § 51.166(p)(3); WAQS&R Chap. 6, § 4(b)(vi).

FLMs are responsible for considering "whether a proposed major emitting facility will have an adverse impact on [air quality related values, including visibility]." (Emphasis added) 42 U.S.C § 7475(d)(2)(B); accord, 40 C.F.R § 51.166(p). Even if the source will not cause or contribute to a PSD increment violation, a permit will be denied if the state concurs with an FLM demonstration that "the emissions from such facility will have an adverse impact on the air quality-related values (including visibility) of [Class I Areas]. (Emphasis added). 42 U.S.C. § 7475(d)(2)(C)(ii); accord, 40 C.F.R. §§ 51.166(p) and 51.307(a)(3); WAQS&R Chap. 6, § 4(b)(vi).

Thus, the FLM's role is to determine whether the proposed source adversely impacts visibility or other air quality-related values (AQRVs). Cumulative impacts are neither regulated nor considered under PSD.

Despite the lack of regulatory authorization, FLMs have issued guidance stating that if modeling of an individual proposed source predicts a change in light extinction equal to or greater than 5% compared with natural conditions, cumulative modeling should be done. Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report (December 2000) (FLAG 2000), at 26-28. If cumulative modeling (or modeling of the source alone) predicts a change in light extinction of 10% or greater, such a change is likely to be deemed an adverse impact and the FLM likely will object to the project. Id. But these percentage thresholds are guidelines only, not mandatory levels.

These FLAG 2000 provisions regarding cumulative visibility modeling go beyond what is authorized in the PSD regulations. Although PSD envisions cumulative modeling for NAAQS and PSD increments, it does not authorize cumulative modeling for AQRVs, including visibility. PSD rules contemplate cumulative modeling for NAAQS and PSD increments, in that a project proponent must demonstrate that the proposed source "would not cause or contribute to" violations of those standards. 42 U.S.C. § 7475)(a)(3); 40 C.F.R. § 51.166(k); WAQR&S Chap. 2, § (c)(2), Chap. 6, § 4(b)(1)(A). But the absence of such "cause or contribute" language respecting visibility and AQRVs clearly indicates an intent that impacts on visibility and AQRVs will not be viewed cumulatively, but for the proposed project only.[1] "[W]here Congress includes

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[1] The FLMs have argued that the existence of "cause or contribute" language at 42 U.S.C. § 7475(d)(2)(C)(i) supports the need for cumulative assessment of Class I AQRVs. Federal Land Managers' Air Quality Relate Values Workgroup (FLAG), Response to Public Comments on Draft Phase I Report, at 5. However, that section merely describes the nature of the notice from an FLM or a state that triggers a requirement to show PSD increments will not be violated, and

particular language in one section of a statute, but omits it in another section of the same Act, it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion." Russello v. United States, 464 U.S. 16, 23 (1983), quoting United States v. Wong Kim Bo, 472 F.2d 720, 722 (5th Cir. 1972); see also, Joseph v. Wiles, 223 F.3d 1155, 1161 (10th Cir. 2000).

Wyoming has recognized that "PSD regulations do not require cumulative visibility analysis to be performed for the proposed new source or modification. Only the visibility impacts from the proposed new source or modification must be assessed as required under current Federal regulations and the Wyoming Air Quality Standards and Regulations. (WAQS&R)" (Emphasis added). In the Matter of a Permit Application (AP-C92) from Black Hills Corporation to Construct a 500 MW Pulverized Coal Fired Electric Generating Facility to be Known as Wygen 2, Decision of the Wyoming Department of Environmental Quality, at 15 (Exhibit 15).

The NPS expresses concern about the cumulative impacts on visibility from the extensive development in the Powder River Basin and around Wind Cave NP, including several projects listed in its comments. NPS Comments at 8-9. However, the agency raises this concern in the context of the Regional Haze Rule, which requires states to develop plans for achieving reasonable progress in improving visibility from both existing and new sources. The NPS is correct in stating that the proper vehicle for addressing cumulative visibility impacts is the Regional Haze Rule. Each state is required to develop reasonable progress goals and strategies for meeting those goals, including enforceable emissions limitations and other measures as necessary. 40 C.F.R. § 51.308(d).

We acknowledge that cumulative visibility impacts are a proper concern for the NPS. But it is the Regional Haze Rule that has been established as the vehicle for addressing cumulative impacts, not the PSD program.

Even if Cumulative Modeling May be Required in Some Cases, It Is Not Warranted in This Case

Even if one assumes for purposes of discussion that cumulative modeling may be required in some cases, cumulative modeling would not be justified in this case. To address NPS concerns, Basin Electric has applied several alternative modeling methods, and evaluated several factors specified in the definition of adverse impact, to demonstrate there is no reasonable basis to conclude that the modeled change in light extinction, taken with other applicable factors, should trigger cumulative modeling under the FLAG 2000 guidelines.

a. Raw Model Results

As noted in the NPS comments, modeling conducted for Basin Electric by CH2M-Hill predicted that, during a period of three meteorological years, without adjustment for natural conditions, and without consideration of other regulatory factors such as frequency, intensity, or time of visitor use, the modeled impact of Dry Fork on visibility would exceed a 5% change in

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is separate from the provision at 42 U.S.C. § 7475(d)(2)(C)(ii) that only an adverse impact from an individual proposed facility is a ground for objecting to a proposed permit.

light extinction on a total of 2 days at Badlands NP (with an impact at the maximum receptor of 5.8%); and on a total of 7 days at Wind Cave NP (with an impact at the maximum receptor of 9.1%).[2] No modeled day shows more than a 10% change, which is the FLMs' guideline threshold for what constitutes an adverse impact under FLAG 2000.

In addition to the percentage change in light extinction, FLMs must take into account other factors, stipulated in the regulations, of geographic extent, intensity, duration, frequency, times of visitor use and natural conditions that reduce visibility. Id. at 15-16; 40 C.F.R. § 51.301(a); WAQR&S Chap. 9, §2(c)(i). During the three years (1095 days), at two National Parks, there are a total of 2190 daily predictions of visibility impacts. Of 2190 modeled daily values, only 9, or less than one-half of one percent, exceeded the 5% level that the FLAG 2000 guideline proposes as a trigger for cumulative modeling. On 4 of these 9 days, the modeled change in light extinction was less than 6%. June 2006 Response, at 8-13 of 15, Exhibit 1. All nine days occurred during the off season, between October 26 and April 6, when the number of visitors to the parks is much lower than during the summer months, or even during the shoulder months of May and September. See Exhibit 1 at 9-13, and the CH2M-Hill report titled "Visitor Day Statistics for Badlands and Wind Cave National Park," June 21, 2007, Exhibit 16.

b. <u>Adjustment for Natural Weather Conditions that Reduce Visibility</u>

Consistent with the PSD visibility rules, CH2M-Hill evaluated each of the 9 days that were modeled above 5% for possible impacts of natural conditions that reduce visibility. NPS Comments, at 8, noted that this evaluation should be made on a more-specific, hour-by-hour basis. The evaluation was, in fact, done on an hour-by-hour basis, as described in detail in Basin Electric's Dry Fork Air Construction Permit Application at Section 8.5.2. Hourly transmissometer data from the IMPROVE monitoring site at Badlands NP and other confirming data were used to identify individual hours when visibility was reduced due to weather conditions such as fog, snow or rain; and for those hours the change in light extinction was calculated using the weather-impacted background visibility rather than the non-impacted natural background values determined in accordance with FLAG 2000. These weather-adjusted hourly values were averaged with non-weather hourly values to calculate daily visibility impacts. After this adjustment for natural weather conditions, there were <u>zero days</u> with a predicted change in light extinction greater than 5% at Badlands and Wind Cave National Parks.. See June 14, 2006 Response, Table 5, at 13 of 15, for a summary of the results. Exhibit 1. After adjustment, the highest change for any of the 9 days was 2.27%, with each of the remaining 8 days being under 1%.

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[2] The NPS comments also list modeling results by the Wyoming Air Quality Division and the National Park Service. However, no data or information regarding this modeling has been made available to Basin Electric. The modeling by Basin Electric was performed in accordance with the Protocol for a CALPUFF Modeling Analysis of the Dry Fork Station Project (Northeast Wyoming Generation Project) dated August 2005, prepared by CH2M-Hill and attached as Appendix H to the Basin Electric Dry Fork Station Air Construction Permit Application dated November 2005. Some model runs included additional meteorological data provided by the Wyoming AQD, as well as a different modeling domain. Computer disks with modeling data have been provided to the Wyoming Air Quality Division and the National Park Service.

Adjustments for "natural conditions that reduce visibility" are expressly provided for in the regulations, 40 C.F.R. § 51.301, WAQR&S Chap. 9, § 2(c)(i), but no particular method for making the adjustments is specified in the rule. Apparently, the NPS disagrees with the details of how these adjustments were made for Dry Fork, but it has not proposed an alternative method for use at Dry Fork. Basin Electric submits that, in the absence of a rule providing otherwise, there is no basis for objecting to the method used by CH2M-Hill, which was based on the best available data and a sound technical methodology.

However, we do not rely solely on CH2M-Hill's methodology. Basin Electric also applied alternative methods suggested by the NPS in comments on other projects. In comments on the Greene Energy Project in Pennsylvania, the NPS suggested that "[t]he appropriate method for calculating a visibility metric that includes meteorological interferences is to use a shorter averaging time that excludes those periods with interference." National Park Service, Preliminary Comments on the Greene Energy Prevention of Significant Deterioration (PSD) Permit Application March 2005, at 8, available at http://www.truthaboutgob.org/NPSGreene_TSD.doc. Applying this approach to Dry Fork, CH2M-Hill reviewed the 9 days with unadjusted values greater than 5% and recalculated 24-hour visibility impacts by excluding those hours with weather interference. The results are shown in CH2M-Hill, Adjustments for Natural Weather Events in Calculating Visibility Impacts, June 21, 2007,at Table 2, Exhibit 17, and indicate that, after this adjustment, only one day out of the total 2190 days exceeds 5%.

In comments on another project, the Intermountain Power Project in Utah, the NPS suspected that transmissometer data used for weather adjustments were being misinterpreted, and therefore applied the alternative "supposition" that hours when relative humidity was greater than 90% "might have been obscured by weather." National Park Service Supplemental Technical Comments on the Intermountain Power Agency Prevention of Significant Deterioration Permit Application For the Addition of Unit 3 at its Intermountain Power Plant, May 2004, at 11, Exhibit 18. The NPS then eliminated those hours from its analysis. Applying this second alternative approach to Dry Fork, CH2M-Hill reviewed the 9 days with unadjusted values greater than 5% and recalculated 24-hour visibility impacts by excluding hours with relative humidity above 90%. The results are shown in Adjustments for Natural Weather Events in Calculating Visibility Impacts, June 21, 2007,at Table 2, Exhibit 17, and indicate that, after adjustment, only four days out of the total 2190 days exceed 5%.

A final alternative was used to adjust for natural weather conditions, based on a methodology introduced by Mr. John Notar of the NPS in a presentation to the April, 2006 Air and Waste Management Association modeling conference. See slide presentation titled "FLM Issues for R/L/F 2006, FLAG Revisions" Exhibit 19. While we understand that this methodology has not been incorporated in agency guidance, it is consistent with the approach adopted by EPA in the Guidelines for Best Available Retrofit Technology (BART) Determinations, under the Regional Haze program, which utilizes the 98th percentile visibility modeling result rather than the maximum modeled visibility impact, because of the tendency of the CALPUFF model to "likely . . . overstate the actual visibility effects of an individual source" and because use of the 98th percentile is "a more robust approach that does not give undue weight to the extreme tail of the distribution." 70 Fed. Reg 39104, 39121 (July 6, 2005). Mr. Notar suggested a potential approach that would use CALPUFF Method 6 rather than Method 2 *(the former using a monthly average relative humidity instead of daily values), a natural background of the 20% best visibility days in a National Park, and the 98th percentile modeled value to determine whether the 5% level is exceeded.*

The results for Dry Fork, using this alternative approach, show zero days above 5% using 98th percentile values. The results are summarized in CH2M-Hill, Dry Fork FLAG2 Processing Using 98th Percentile and 20 Percent Cleanest Days as Background, May 24, 2007, Exhibit 20.

c. Conclusions Based on the Data and Modeling Results

The modeling results discussed above should be viewed in the context that FLAG 2000 is not a rule, is not mandatory, and does not bind either the FLMs or the Wyoming Air Quality Division. "It is important to emphasize that the FLAG report is only a guidance document that explains factors and information the FLMs expect to use when carrying out their consultative role. It is separate from Federal regulatory programs." FLAG 2000 at 5. See also, Prairie State EAB Decision at 159-160 ("we have frequently held that 'an agency cannot, consistent with Administrative Procedure Act, . . . utilize a policy statement as if the policy were a 'rule' issued in accordance with APA 'rulemaking procedures'" and that "[t]he agency must, in some meaningful way, keep an 'open mind' about the issues addressed in the policy document, and cannot act as if those issues are no longer subject to debate." (citation omitted)).

Basin Electric submits that, considering all of the foregoing analyses and modeling results, and the fact that FLAG 2000 is guidance only, the most reasonable conclusion is that the Dry Fork project will not have an adverse impact on visibility in any Class I Area, and that cumulative modeling is not warranted. Even if, contrary to the language of the PSD rules, we assume that cumulative modeling for visibility impacts may appropriately be considered in the PSD context, the following factors, individually and collectively, support that conclusion:

- *Even unadjusted for natural weather conditions, model results exceed 5% change in light extinction on only 9 of 2190 days.*
- *4 of the 9 days have less than 6% change in light extinction, unadjusted.*
- *None of the 9 days exceeds 10%, unadjusted.*
- *All of the 9 days occur between late October and early April, when visitor use is a fraction of summer visitor levels.*
- *Considering the low intensity and low frequency of values over 5% and that all such values occur during the off-season, even unadjusted values should not trigger cumulative modeling.*
- *Both the initial method used by CH2M-Hill to adjust for natural weather conditions, and the 98th percentile approach that has been suggested by NPS staff and adopted by EPA in its Guidelines for BART Determinations, yield zero days greater than 5% change in light extinction.*
- *Alternative methods suggested by the NPS in comments on other projects yield either one to four days greater than 5% change in light extinction out of 2190 daily values, or between one-twentieth of one percent and two-tenths of one percent.*
- *EPA acknowledges that visibility modeling with the CALPUFF model is subject to significant uncertainties and tends to overstate actual impacts.*

Two reasonable methods, including the 98th percentile method which was adopted by EPA and suggested as an alternative by NPS staff, and which produces more robust results and avoids outcomes driven by outlier values, yield zero days above 5% light extinction. The two alternative methods suggested in individual cases by the NPS yield one or four days out of 2190, or between one-twentieth and two-tenths of one percent, with values above 5%. In light of all the factors listed above, insistence on cumulative modeling in this case would rest on the thinnest foundation. No further modeling should be required, and it should be acknowledged that Dry Fork will not adversely impact visibility in any Class I Area.

NPS Comment #14 (p. 9-11)

Modeled sulfur deposition from Dry Fork at Wind Cave NP exceeds a Deposition Analysis Threshold that triggers concern and warrants further consideration.

Response: *Because modeling of sulfur deposition from the Dry Fork project at Wind Cave National Park was slightly higher than the NPS' Deposition Analysis Threshold (DAT), the NPS commented that sulfur deposition triggers management concerns and warrants further consideration, and requested that Basin Electric conduct an analysis of sulfur deposition impacts. NPS Comments at 9-11. Basin Electric believes that no further analysis should be needed to satisfy concerns about impacts in the Park, but nonetheless has conducted a further analysis that demonstrates there is no reason for concern.*

As the NPS acknowledges in its comments, "the DAT is a deposition threshold, not necessarily an adverse impact threshold." NPS Comments at 10. The Guidance on Nitrogen and Sulfur Deposition Analysis Thresholds, developed by the NPS and the U.S. Fish and Wildlife Service, available at http://www2.nature.nps.gov/air/Pubs/pdf/flag/nsDATGuidance.pdf, at 1, provides that the DAT "is the additional amount of N or S deposition within a Class I area, below which estimated impacts from a proposed new or modified source are considered insignificant." (Emphasis in original). In the West, the agencies "selected very conservative natural background numbers" for sulfur (and nitrogen) deposition—0.25 kg/ha/yr. They concluded that 50% of the natural background could be added without adversely affecting the ecosystem, and then took 4% of that 50% as an insignificant level that could added by an individual source without raising concerns about cumulative impacts. Id. at 2-4. Thus the DAT is a small fraction of conservative natural background levels.

As with the FLAG 2000 guidance, the DAT guidance is not a regulation and has no binding effect. It is based on "very conservative" values. Moreover, modeling impacts with the CALPUFF model tends to overestimate those impacts. 70 Fed. Reg. 39104, 39121 (July 6, 2005). The modeled impact from Dry Fork is only slightly higher than the conservatively protective DAT. And the NPS acknowledges that "sulfur deposition has been decreasing at the monitoring site with long-term data nearest Wind Cave." NPS Comments at 10. We submit, therefore, that there is no reason for concern about ecosystem impacts.

Nonetheless, Basin requested CH2M-Hill to conduct a further analysis of sulfur deposition at Wind Cave NP to ascertain whether there is any reason for concern. The results of that analysis are reported in CH2M-Hill, Dry Fork Cumulative Sulfur and Nitrogen Deposition Analysis, June 15, 2007, Exhibit 21. As noted in the CH2M-Hill report, The NPS website for

Wind Cave NP indicates: (1) that "there are decreasing trends in wet sulfate concentration"; (2) that data from the nearest monitoring site "indicate that there is no apparent threat from acid deposition at this time"; and(3) that "[s]urface water chemistry data have been collected in and near Wind Cave NP" which "indicate park surface waters are well buffered against acid inputs." Available at http://www2.nature.nps.gov/air/Permits/ARIS/WICA/.

The Wind Cave website in turn refers to D.L. Peterson, et al., Assessment of Air Quality and Air Pollutant Impacts in National Parks of the Rocky Mountains and Northern Great Plains, 1998, Technical Report NPS D-657, which specifically addresses deposition at Wind Cave NP in Chapter 8, and states that: (1) "[t]he values for S and N deposition, in combination with wetfall input of hydrogen and other ions, indicate that [Wind Cave] is a relatively clean site and that there is no apparent threat from acidic deposition at the present time"; (2) that "[s]urface waters are expected to be well-buffered against acid inputs"; and (3) that "[t]here is no evidence to suggest that surface waters in [Wind Cave] would be responsive to acidic deposition impacts or that aquatic biota would be affected." Available at http://www2.nature.nps.gov/air/Pubs/pdf/reviews/rm/RM8wica.pdf. The NPS web page for AQRVs at Wind Cave NP states that surface waters and soils appear to be well-buffered and that neither aquatic resources nor soils appear to be sensitive AQRVs. Available at http://www2.nature.nps.gov/air/Permits/ARIS/wica/aqrv.cfm.

Additional analysis by CH2M-Hill corroborates the NPS' own conclusions that Wind Cave is not threatened by acidic deposition and will not be affected by sulfur deposition from Dry Fork. Monitoring data from the nearest stations indicate that the current rate of measured deposition of total sulfur is 1.02 kg/ha/yr or less. The highest modeled contribution from Dry Fork is 0.008 kg/ha/yr, or less than 1% of the total. The question is whether the combination of existing sulfur deposition and the additional deposition from Dry Fork would exceed the "critical load," which is "the concentration of air pollution above which a specific deleterious effect may occur." FLAG 2000 at 129. We are unaware of any quantitative critical load values that have been developed specifically for Wind Cave NP. However, FLAG 2000 cites a paper by D.G. Fox, et al, A Screening Procedure to Evaluate Air Pollution Effects on Class I Wilderness Areas, 1989,General Technical Report RM-168, available at http://www.treesearch.fs.fed.us/pubs/6242. We are aware that the NPS regards this paper as dated. However, in the absence of a site-specific critical load, it provides a quantitative "Green Line" or generally "acceptable" value for sulfur deposition of 3 kg/ha/yr. "Pollutant doses less than the Green Line value might be judged permissible by managers, and the application recommended for approval without additional data." Id. at 4. Existing sulfur deposition, plus the less than 1% increase from Dry Fork, is approximately one-third of this generally acceptable value.

Thus, regarding sulfur deposition at Wind Cave:

- *The impact of Dry Fork is only slightly higher than the "very conservative" DAT*
- *Dry Fork's contribution to existing sulfur deposition is less than 1%, and total sulfur deposition is decreasing*
- *Total sulfur deposition is far below the only available quantified critical load value*
- *Sulfur deposition at Wind Cave has been determined by the NPS to pose no threat to aquatic or soil resources*

Therefore, there is no reason to fear that sulfur deposition from Dry Fork will in any way adversely impact AQRVs at Wind Cave NP.

NPS Comment #15 (p.11)

Although Devil's Tower National Monument is a Class II area, not a Class I area, Basin Electric should provide estimates of sulfur and nitrogen deposition for Devil's Tower.

Response: *Although NPS policies may direct the agency to protect all areas for which it has responsibility, and although the agency may have responsibilities regarding Devil's Tower, it has no authority under the PSD program to require a permit applicant to evaluate potential impacts on AQRVs in Class II areas, and the NPS cites no such authority.*

Nonetheless, because of the request by the NPS, Basin Electric voluntarily has evaluated atmospheric deposition at Devil's Tower, the results of which are reported in CH2M-Hill, Dry Fork Cumulative Sulfur and Nitrogen Deposition Analysis, at 5-5, Exhibit 21. The analysis shows that, although modeled deposition at Devil's Tower from Dry Fork exceeds the NPS Deposition Analysis Thresholds for sulfur and nitrogen deposition, cumulative analysis shows that the combination of existing measured deposition plus the modeled contribution from Dry Fork is about one-third or less of the Green Line value, below which negative effects are not expected. Therefore, there will be no adverse impacts to AQRVs resulting from Dry Fork emissions.

ENV Comment # 1

WDEQ failed to meet public notice requirements by not fully addressing increment consumption in the public notice.

Response: *The regulation cited provides that the public notice will include mention of the anticipated degree of increment consumption, but provides no further detail respecting what is required. As acknowledged by ENV, the original public notice did include the anticipated increment of SO_2 consumption near the plant site. The WDEQ's interpretation and application of the notice requirement in this case is entitled to deference. Further, however, in response to comments, the WDEQ has scheduled a public hearing on the Dry Fork permit on June 28, 2007, and extended the comment period to that date. The published notice of the public hearing includes additional information concerning increment consumption, for all PSD increment-consuming pollutants and at all pertinent locations. Even if we assume that previously there was a ground for objection, no such ground exists now.*

ENV Comment #2(1)

The proposed Dry Fork permit and Basin Electric's permit application fail to address carbon dioxide and other greenhouse gas emissions. EPA and the State of Wyoming have a legal obligation to regulate CO_2 under the Clean Air Act. ENV note that the question of whether EPA has authority to regulate greenhouse gases under the Clean Air Act was before the Supreme Court in *Massachusetts v. EPA,* 127 S.Ct. 1438 (2007), at the time their comments were filed. ENV also assert that regulation of CO_2 emissions in the United States in the "very near future is virtually certain" in light of state, federal, and international efforts targeting climate change.

Response: *There is no current statutory duty for EPA or WDEQ to limit CO_2 emissions from stationary sources. While Congress is considering a number of bills to address various aspects of climate change, at this point in time Congress has not enacted legislation regulating greenhouse gas emissions. Basin Electric will be obligated to comply with any such future requirements when they are enacted. Until that time, ENV's assertions about the imminence of climate change legislation do not create a present regulatory duty, nor do they provide any basis for speculating what the substance of any such future regulation might be.*

Likewise, at the present time the Clean Air Act (CAA) does not require EPA and WDEQ to regulate CO_2 emissions for stationary sources under the PSD program. Since ENV submitted their comments on the Dry Fork Permit Application Analysis, the Supreme Court has issued a ruling in the Massachusetts v. EPA litigation. In that case, the Supreme Court held that CO_2 is a "pollutant" under the CAA, and that EPA has authority to regulate emissions of greenhouse gases from new motor vehicles under Title II of the CAA. 127 S.Ct. at 1462. In light of its finding that EPA may regulate such emissions, the court remanded the case so that EPA could properly fulfill the requirement under 42 U.S.C. § 7521(a)(1) that EPA exercise its judgment whether greenhouse gases cause or contribute to air pollution that "may reasonably be anticipated to endanger public health or welfare." Id. *The Supreme Court did not make any findings regarding whether the CAA obligated or authorized EPA or WDEQ to regulate emissions of CO_2 from stationary sources.*

While the decision in Massachusetts v. EPA *established that CO_2 is a pollutant under the CAA, the relevant question for purposes of the BACT analysis is whether it is a regulated pollutant for NSR purposes. The CAA provides that n*o major emitting facility may be constructed unless:

> *the proposed 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.*

42 U.S.C. § 7475(a)(4) (emphasis added). Best available control technology (BACT) is defined as:

> *an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility . . . .*

42 U.S.C. § 7479(3) (emphasis added). Regulations describing requirements for state implementation plans provide a similar definition of BACT, and identify a specifically-defined set of "regulated NSR pollutants" that are subject to regulation under the CAA:

> *Best available control technology means an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each a [sic] regulated NSR pollutant which would be emitted from any proposed major stationary source or*

> *major modification which the reviewing authority, 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 . . . .*

40 C.F.R. § 51.166(b)(12). Thus, WDEQ is not required to conduct a BACT analysis for any possible pollutant, but rather for a defined class of "regulated NSR pollutants."

Regulated NSR pollutants include:

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

40 C.F.R. § 51.166(b)(49). In other words, a BACT analysis must consider emissions of pollutants regulated under National Ambient Air Quality Standards (NAAQS), new source performance standards (NSPS), substances that damage stratospheric ozone, and pollutants "otherwise subject to regulation" under the CAA, with the exception of hazardous air pollutants (HAPS) regulated under section 112.

A pollutant is not "subject to regulation" for NSR and BACT purposes merely because it is a pollutant under the CAA. Such a reading of subsection (iv) would render subsections (i) – (iii) superfluous. To the contrary, subsection (iv) only includes pollutants currently regulated under the CAA in some manner not mentioned in subsections (i) through (iii).

This conclusion is supported by the preamble to a final rule published by EPA in the Federal Register. See 67 Fed. Reg. 80,240 (December 31, 2002). In that publication, EPA addressed the reason it was adding the term "regulated NSR pollutant" to its PSD regulations:

> *One commenter requests that we amend the regulations to include a definition of pollutants regulated under the Act. We agree with the commenter that such a provision would clarify which pollutants are covered under the PSD program. Therefore, today's final regulations include a definition for regulated NSR pollutant.*

Id. (emphasis added). This language clearly demonstrates that there are various pollutants which are not covered under the PSD program and therefore not subject to BACT.

Guidance for making an applicability determination under the PSD program in EPA's NSR Manual, USEPA, October, 1990 (NSR Manual), indicates that regulated NSR pollutants include only pollutants regulated under final rules promulgated by EPA. A stationary source is subject to PSD permitting in the first instance if it is: (1) one of a set of enumerated sources with the potential to emit 100 tpy of any regulated NSR pollutant(s), 40 C.F.R. § 51.166(b)(1)(i)(a); (2) any other stationary source with the potential to emit 250 tpy of any regulated NSR pollutant(s), 40 C.F.R. § 51.166(b)(1)(i)(b); or (3) a modification to an existing source that would result in a significant emissions increase, 40 C.F.R. § 51.166(b)(2)(i). See 40 C.F.R. § 51.166(a)(7)(iii). When discussing how to determine a source's "potential to emit" the EPA NSR Manual lists those "pollutants regulated under the Clean Air Act" (as of December 31, 1989). EPA NSR Manual A.19-A.21. Furthermore, a table summarizing significant emission rates for regulated pollutants notes, "Regulations covering several pollutants ... have recently been proposed. Applicants should, therefore, verify what pollutants have been regulated under the Act at the time of application." Id. at A.21, Table A-4, note (d) (emphasis added). Thus, those pollutants will not be "regulated" for purposes of the PSD program until the proposed regulations are finalized.

This guidance is consistent with the EPA's ruling in In the Matter of: North County Resource Recovery Associates, 2 E.A.D. 229 (EAB 1986). There the Administrator determined that hazardous air pollutants (HAPs) that are unregulated under the PSD program nonetheless could be taken into account in evaluating environmental impacts when evaluating Best Available Control Technology (BACT), even though they were not directly subject to BACT. This ruling was made before the 1990 Clean Air Act Amendments exempted HAPs from PSD, so at the time HAPs could potentially be subject to PSD. Although the HAPs in question were pollutants, and although EPA had the authority to regulate them, HAPs for which regulations had not been adopted were deemed unregulated for purposes of PSD, and BACT evaluation was not required for them. BACT is required only for pollutants actually regulated under the Clean Air Act.

The North County conclusion was recently reaffirmed by EPA in the preamble to the agency's December 31, 2002 PSD/NSR rule revisions, 67 Fed. Reg. 80186, 80239-40, in which EPA adopted a definition for "regulated NSR pollutant." In the preamble, the agency listed only 14 pollutants which are "currently regulated under the [Clean Air] Act" that "are subject to Federal PSD review and permitting requirements." It went on to say "[t]he PSD program applies automatically to newly regulated NSR pollutants, which would include final promulgation of an NSPS applicable to a previously unregulated pollutant." Id. (emphasis added). Therefore, not all pollutants are subject to PSD. They become subject to PSD only when they actually become regulated under the Clean Air Act.

Although "pollutant" is broadly defined, pollutants that are "subject to regulation" constitute a much smaller subset. The Supreme Court found in Massachusetts that the term "pollutant" is expansive and can include virtually anything emitted into the air. See Mass. v. EPA, 127 S.Ct. at 1460 ("the definition [of air pollutant] embraces all airborne compounds of whatever stripe"). Under Title II, the CAA requires EPA to regulate air pollutants emitted from new motor vehicles that "are reasonably . . . anticipated to endanger public health or welfare." 42 U.S.C. § 7521(a)(1) (emphasis added). However, until and unless an endangerment finding is made for a pollutant, including CO_2, and standards are adopted, it is not "subject to regulation" under PSD.

Subsections (i) through (iii) of 40 C.F.R. § 51.155(b)(49) regulate pollutants under programs that require a similar "endangerment" determination before regulating a pollutant. See 42 U.S.C. § 7408 (Administrator must issue air quality criteria and NAAQS for pollutants, emissions of which cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare); 42 U.S.C. § 7671a(a) and (c) (Administrator may add substances known or reasonably anticipated to contribute to harmful effects on the stratospheric ozone layer to lists of Class I and II substances); and 42 U.S.C. § 7411(b) (Administrator must issue new source performance standards for categories of sources that cause or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare). It is reasonable to expect that a pollutant "otherwise is subject to regulation" only after it has undergone a similar endangerment determination and regulations have been adopted.

This is precisely the determination that the Supreme Court directed EPA to make on remand in Massachusetts v. EPA. Because EPA has not yet made such a determination or promulgated a rule, CO_2 is not a regulated NSR pollutant, and CO_2 emissions need not be considered in the BACT process.

Finally, it should be noted that CO_2 is not a pollutant subject to regulation under the Wyoming Air Quality Standards and Regulations. In other words, Wyoming does not independently regulate CO_2. Instead, Wyoming incorporates applicable federal standards, as discussed above, into its own Air Quality Standards and Regulations.

ENV Comment #2(2)

At the minimum, WDEQ should have required consideration of emissions of CO_2 in the Dry Fork best available control technology (BACT) analysis. Even if WDEQ does not conclude that CO_2 is a regulated pollutant under the CAA or state clean air laws, it still must assess any differences in the potential global warming impacts as part of the mandatory collateral impacts analysis. ENV cite *In the Matter of: North County Resource Recovery Associates,* 2 E.A.D. 229 (EAB 1986), for the principle that impacts of non-regulated pollutants must be considered when selecting BACT. It is "simply untenable" that the effects of global warming are inherently outside the scope of the collateral impacts analysis, and any assertion that CO_2 emissions and global warming are beyond the scope of the PSD program must be rejected.

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, the impacts from the generation of hazardous wastes, and impacts on species and habitat.

Response: *The consideration of collateral impacts is one step in the overall BACT analysis. EPA recommends the use of a "top-down" BACT process that includes five steps, described in the EPA NSR Manual as follows. Step 1 is the identification of all control options with potential application to the source and pollutant under evaluation, and includes inherently lower polluting processes and add-on controls, but does not require the permit applicant to redefine the proposed source. Step 2 considers the technical feasibility of the options identified in Step 1 and takes into account whether a control technology has been successfully installed and operated on the type of source under review or otherwise is "available" and "applicable" as defined in the EPA NSR Manual. Step 3 ranks the technically feasible alternatives in order of the most to the least effective. Step 4 evaluates the energy, environmental and economic impacts of each option, to determine whether the top-ranked option should be eliminated in favor of another option based on these factors. At Step 5, the most effective control option not eliminated at Step 4 is selected as BACT.*

The North County decision held that EPA had "clear" authority to evaluate the collateral environmental impact of unregulated pollutants in the course of making a BACT determination in the sense that, "[I]f application of a 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." 2 E.A.D. 229, 230 (Adm'r 1986). In other words, EPA may choose a different technology for a regulated pollutant, with its associated emissions, than it might otherwise choose if doing so would have the incidental benefit of restricting an unregulated hazardous pollutant. ENV cite no cases that would support expanding the holding of North County from consideration of hazardous air pollutants to consideration of incidental benefits regarding CO_2 *emissions.*

The North County decision is inapposite to the consideration of IGCC technology for Dry Fork Station for two reasons: (1) IGCC is not an available or feasible emissions control technology for a PC plant; and (2) if analyzed as a "control technology", components of an IGCC plant that reduce emissions of criteria pollutants would not incidentally control CO_2*.*

IGCC is not a potential control technology under the BACT process, but rather, it is a distinct power generation technology, separate and apart from a PC plant. It is not an "add-on" emission control technology that could be installed on the front end or back end of a PC power plant. Therefore, IGCC would be eliminated at Step 1 since it involves redefining the source, as discussed in response to ENV Comments #4 and 5, infra pp. 69-78, or at Step 2 due to technical infeasibility. See infra pp. 81-82. Consideration of the collateral impacts of a control technology does not take place until Step 4 of the BACT analysis (after ranking the control effectiveness of available technologies in Step 3). As the EPA NSR Manual states, "Step 4 validates the suitability of the top control option in the listing for selection as BACT, or provides a clear justification why the top candidate is inappropriate as BACT." EPA NSR Manual at B.26. Evaluation of collateral impacts at Step 4 applies to those control technologies still under consideration—it does not create a mechanism for considering a new technology not evaluated in the earlier BACT steps, nor for "reviving" a technology already eliminated based on other *criteria. "In Step 3, all remaining control alternatives <u>not eliminated in step 2</u> are ranked and then listed in order of over all control effectiveness . . . ." EPA NSR Manual at B.7. Having been eliminated at Step 1, and again at Step 2, IGCC is not eligible for consideration at Steps 3 and 4.*

Even if IGCC could be vi ewed as a control technology and ranked among available technologies in Step 3 of a BACT analysis for Dry Fork Station, consideration of collateral environmental effects would not require selection of IGCC as the preferred technology. The <u>North County</u> decision explains that where the application of a control technology for a regulated pollutant "results directly in the release (or removal) of pollutants" that environmental impact may be considered in making the BACT determination. Here, the application of IGCC as a "control technology" would not directly result in removal of CO_2, because CO_2 capture is not inherently part of the IGCC process (just as CO_2 capture is not in inherent part of PC technology). Specific equipment and systems for capturing and compressing the CO_2 must be added. CO_2 capture for IGCC involves three steps: shift reactors, which convert H_2O and CO to CO_2 and H_2; a CO_2 separation process; and CO_2 compression and drying. The Future of Coal: Options for a Carbon-Constrained World (MIT 2007) ("MIT Report") at 34, available at http://web.mit.edu/coal/. As a result of the CO_2 capture process, combustion turbine modifications are also required to efficiently burn the resulting gas stream, which is primarily composted of hydrogen. Id.

*IGCC itself does not capture or sequester CO_2. Therefore, any collateral environmental benefits from reduced CO_2 emissions would result not from applying IGCC as a control technology, but from adding the shift/separation/compression process. However, application of such a control technology is beyond the scope of environmental considerations that may be weighed in BACT, because the control technology does not reduce emissions of regulated pollutants. The Environmental Appeals Board has explained, "Unless the advocated additional control technology is available for the primary purpose of controlling emissions of regulated pollutants, the permit issuer is not required to include that control technology in the BACT analysis or consider, as a secondary matter, the effect of that technology on unregulated pollutants or its other collateral environmental impacts." <u>In re Genessee Power Station</u>, 4 E.A.D. 832, at *41. (EAB, 1993) Capturing CO_2 from an IGCC plant would require a separate, add-on control technology to remove CO_2 from syngas prior to combustion. This is parallel to a separate CO_2 capture process that might be added on to a PC plant to remove CO_2 from flue gas, such as an amine scrubber. Any environmental benefits of that distinct CO_2 capture process would not be "collateral" to the removal of regulated pollutants, and are not a relevant consideration when determining BACT.*

It is important to recognize that selection of IGCC as a power generation technology does not inherently include or guarantee CO_2 capture, and selection of PC does not preclude it. A recent report by an MIT study group acknowledged that, "with an uncertain future policy environment, significant pre-investment for CO_2 capture is typically not economically justified." MIT Report at 29. At present, building "capture-ready" IGCC plants amounts to little more than leaving "floor space" for future equipment:

> *Pre-investment for later retrofit will generally be unattractive and will be unlikely for a technology that is trying to establish a*

competitive position. However, for IGCC, additional space could be set aside to facilitate future retrofit potential.

Id. at 38.

Naturally, there are costs and technical challenges associated with retrofitting a PC plant for CO_2 capture, as well. However, these issues are not insurmountable, and will be mitigated as technology improves. See generally, MIT Report at Appendix 3.E. The design of Dry Fork Station contains space currently estimated to be adequate for possible future CO_2 equipment if such processes become possible and necessary. The Electric Power Research Institute (EPRI), conducts extensive R&D on CO_2 capture technologies for both IGCC and PC. A recent article in the EPRI Journal notes that "several improvements have been identified that potentially could sufficiently enhance performance of PC plants using post-combustion capture that they would be competitive with IGCC using pre-combustion capture." Douglas, John, "The Challenge of Climate Change," EPRI Journal (Spring 2007) at 16, available at http://mydocs.epri.com/docs/CorporateDocuments/EPRI_Journal/2007-Spring/1014795.pdf.

Even assuming that the capture of CO_2 (from either a PC or IGCC plant) were technically feasible, it would be of no environmental benefit without a means to sequester and ensure the long-term confinement of the captured CO_2. Notably, developers of one IGCC plant recently announced they were delaying the project, as they would not be able to comply with Washington State's new law requiring CO_2 capture and sequestration. Whether or not the project eventually moves forward will depend on the outcome of agency rulemaking implementing the new legislation. "Energy Northwest assesses impact of newly passed legislation," Keeping Current (May 2007) at 3, available at http://www.energy-northwest.com/news/keeping_current/05-2007%20Keeping%20Current.pdf. In December 2006, EPA was required to issue a supplemental draft environmental impact statement for a Pennsylvania coal-to-clean fuels and power project because it had incorrectly assumed that CO_2 removed from the fuel stream could be sequestered or sold. In fact, the CO_2 was to be vented because sequestration technology was not sufficiently developed and no adequate industrial market existed for the volume of CO_2 in question. Supplement to the Draft Environmental Impact Statement for the Gilberton Coal-to-Clean Fuels and Power Project, DOE/EIS-0357D-S1 (Dec. 2006), available at http://www.fossil.energy.gov/programs/powersystems/cleancoal/publications/wmpi_supplement_eis.pdf.

Long-term CO_2 sequestration is not currently available at a commercial scale. There is a substantial body of experience injecting CO_2 for enhanced oil recovery (EOR) purposes, but knowledge of reservoir properties and experience with injection techniques for deep saline aquifers—the formations with the greatest capacity and to hold the greatest potential for long-term sequestration—is much more limited. The regulatory framework for permitting sequestration projects is also at an early stage of development. In March 2007, EPA issued guidance on permitting pilot-scale CO_2 sequestration projects as part of its Underground Injection Control Program. Using the Class V Experimental Technology Well Classification for Pilot Geologic Sequestration Projects, UIC Program Guidance #83 (March 1, 2007), available at http://www.epa.gov/safewater/uic/pdfs/guide_uic_carbonsequestration_final-03-07.pdf. However, regulations for commercial-scale projects may not be ready until 2012. Other *necessary elements of widely-deployed, commercial-scale CO_2 sequestration, such as a robust pipeline system for transport of CO_2, are also lacking at the present time.*

Although Basin Electric determined that IGCC (with or without CO_2 capture) was not available to meet project needs at the Dry Fork Station, Basin Electric is currently involved in other activities to promote R&D on CO_2 capture and sequestration issues. Basin Electric is involved in the largest coal-based sequestration project in the world through its wholly-owned subsidiary Dakota Gasification Company, which operates the Great Plains Synfuels Plant near Beulah, North Dakota. This is the largest coal gasification plant in North America (not an IGCC power plant), used for converting lignite to synthetic natural gas. Dakota Gasification sells CO_2 to oil producers in Saskatchewan, Canada where it is used for EOR in an aging oil field. The CO_2 is recovered by a Rectisol process, compressed to a pressure of nearly 2,700 pounds per square inch, and transported by pipeline over 200 miles to Weyburn, Saskatchewan. The CO_2 is expected to be permanently sequestered in the oil reservoir and is being monitored by the International Energy Agency Weyburn CO_2 Monitoring and Storage Project. See Repsonse to ENV Comment #3, infra pp. 66-69, for discussion of other Basin Electric activities related to climate change and renewable energy.

ENV assert that additional collateral environmental impacts of IGCC, including water use, solid waste, and species and habitat impact require that IGCC be selected as BACT. However, as discussed previously, collateral environmental considerations do not require selection of a technology that is not already being considered as part of the BACT process. IGCC is not a control technology applicable to a PC plant. Including IGCC would mean requiring a redefinition of the source, or use of a technology that is not technically feasible for the parameters of Dry Fork Station. As a result, any such collateral impacts are beyond the scope of the BACT analysis.

ENV Comment #3

WDEQ and Basin Electric must consider the collateral costs of future CO_2 regulation in the BACT analysis, and BACT options that are less intense emitters of CO_2 should be given preference. ENV state there is a "general consensus" that federal CO_2 emissions controls are "inevitable" and assume that power generation in particular coal-fired generation "is certain to be among the first industry sectors affected by carbon-related regulation." Industry would consider it cost prohibitive to consider retrofits for a pulverized coal plant in order to seriously address CO_2 emissions (by installing CO_2 capture and control equipment for example). Businesses are increasingly recognizing the monetary risk associated with impending carbon emission controls.

Response: *Speculative consideration of future regulation is entirely outside the scope of the BACT process. BACT identifies and evaluates currently available control technologies to discern which is BACT. Even if a technology survives to Steps 3 & 4 of BACT, speculation concerning future legislation is not part of the BACT process. Step 4 considers only energy, environmental and economic impacts that are known or reasonably knowable. Consideration of potential future legislation and related developments is part of the business planning process, not part of BACT.*

As in the case of environmental considerations, collateral economic impacts cannot "revive" at Step 4 of BACT a technology that has been evaluated and eliminated at an earlier step of the BACT analysis. Nor can they require consideration of an entirely new process that would require redefining the source. Even if IGCC had not been eliminated at Steps 1 or 2, there is no authority and ENV cite no authority requiring that speculative future legislation is a proper consideration under BACT.

ENV suggest a radically expanded concept of economic impacts, but do not cite any precedent in support of their interpretation, which would require speculation about both the future regulatory regime that may apply to CO_2 emissions and future control technologies that may be available to capture CO_2 from PC or IGCC plants. Congress is currently considering a number of bills that would address greenhouse gas emissions and climate change issues. EPA may also undertake rulemakings or other regulatory activities to seek to address CO_2 under the Clean Air Act. At such time as CO_2 emissions from power plants may become regulated, Dry Fork Station will be obligated to comply, whether through emissions reductions, purchasing allowances under a cap and trade system, or procuring other offsets as applicable under such regulation. Because the obligations themselves have not yet been determined, estimates of future compliance costs cannot be meaningfully incorporated into the BACT analysis.

Estimating future compliance costs also involves making assumptions about the nature and cost of technology that will be available at the time any future regulations enter into force. There is much optimism surrounding the potential for relatively low-cost capture of CO_2 from syngas in an IGCC process. However, CO_2 capture from IGCC is not yet a demonstrated process that has been proven in practice. A 2007 report by an MIT study group on "The Future of Coal" concluded that "it is clear there is no technology today that is an obvious silver bullet [for cost-effective CO_2 capture]." MIT Report at 38. The report notes that comparisons of the cost of electricity (COE) strongly favor PC technology over IGCC for coals with low heating value (i.e. Power River Basin sub-bituminous coal). Id. at 37. When CO_2 capture is taken into account, the COE gap is reversed for high-heating value bituminous coals, "but as coal heating value decreases, the COE gap is substantially narrowed." Id. The report further recognizes that "ultra-supercritical PC combustion and lower energy consuming CO_2 capture technology, when developed, could have a lower COE than . . . IGCC with CO_2 capture." Id. at 37. The report concludes that while IGCC will be the lowest net present value cost alternative for some reasonable set of assumptions regarding future CO_2 regulations (including timing, tax rate, retrofit costs, and grandfathering) assuming today's technology performance, "[s]ubstantial technology innovation could change the outcome, as could changing the feed from bituminous coal to lignite." Id. at 38. Thus, is it not even clear in the first instance that, given the sub-bituminous coal fuel source and other particulars of the Dry Fork Station project that IGCC is presently the least-cost control technology or would be at some point in the future. Certainly, *there is sufficient uncertainty that future CO_2 control costs cannot drive the BACT selection process.*

ENV cite various activities undertaken by corporations as evidence that they are "increasingly recognizing the monetary risk associated with impending carbon emissions controls." Basin Electric agrees that there is a growing awareness of the potential financial implications of future regulation of CO_2 emissions. However, the issue is, at its core, a business decision outside the scope of PSD permitting or a BACT analysis. The BACT process should not be used to trump a business judgment dependent on a variety of uncertain variables and assumptions ranging from costs for new or retrofit technology, to risk tolerance among members and investors. Basin Electric will likely be subject to any future CO_2 regulation for stationary sources, whatever shape it takes, and may reasonably choose, for example, to rely on future technology improvements that may be available to meet future obligations, rather than speculate about its obligations under a future regulatory regime and be an early adopter of unproven or unreliable technology.

Furthermore, Basin Electric's determination that IGCC could not meet the purpose and need for the Dry Fork Station in no way demonstrates that Basin Electric is failing to actively address climate change issues and prepare for the possibility of future regulation. Basin Electric is actively engaged in developing strategies to implement early CO_2 reductions for the cooperative. Basin Electric has been proactive in the building of renewable generation, including 136 MW of wind generation developed in collaboration with FPL Energy since 2002, power purchases from other small wind generators, and installation of recovered energy electrical generation facilities using waste heat from natural gas pipelines. As noted above, Dakota Gasification, a Basin Electric subsidiary, provides CO_2 for EOR-based sequestration in the Weyburn oil field.

Basin Electric has developed a Carbon Dioxide Business Plan focused on the capture of CO_2 from stack gases on a commercial scale and expanding sales of CO_2 for EOR. Basin Electric is also a member of several organizations such as the Electric Power Research Institute, Plains CO_2 Reduction Partnership, Canadian Clean Power Coalition and the Lignite Technology Development Workgroup that are working to gain a better understanding of CO_2 capture and sequestration technologies. Basin Electric recently issued a Request for Proposal to technology providers that would ultimately lead to CO_2 capture demonstration at Basin Electric's Antelope Valley Station, a lignite-based PC power plant. Basin Electric has also been involved in R&D efforts to relating to an IGCC "transport reactor" utilizing a dry feed system to the gasifier and operating temperatures favorable to high-moisture lignite, and is currently working with a GE/Bechtel IGCC Alliance on the development of an IGCC sub-bituminous reference plant using GE gasification technology.

ENV argue that it is "simply untenable" that effects of global warming would be "inherently outside the scope" of the collateral impacts considered in connection with PSD permits. But this argument mischaracterizes the role of BACT. There may be good reason to address climate change through legislation or regulation, but BACT is not designed to accomplish that purpose. BACT is a case-by-case method to discern appropriate emission limits for an individual source. The current state of the law does not require an applicant to redefine the design of the proposed source as part of the BACT process. IGCC is a fundamentally *different technology from a PC plant, and cannot meet the project purpose for Dry Fork Station, and need not be considered as BACT. Furthermore, IGCC is not a demonstrated, technically feasible process for a 385 MW plant using sub-bituminous coal at altitude. Because BACT is not an available, feasible control technology ranked at Step 3 of the BACT process, there is no basis to re-introduce IGCC at Step 4, which is intended to evaluate only technologies not previously eliminated. If EPA promulgates rules regulating CO2 in BACT or otherwise under the CAA, or if Congress passes climate change legislation addressing greenhouse gas emissions, Basin Electric will have a legal obligation and will comply with those future requirements. In the meantime, the types of policy arguments raised by ENV are best addressed in other settings. Basin Electric is doing so through its development of renewable energy resources, promotion of CO2 sequestration through research and—in the context of EOR—in practice, and collaboration in the development of a sub-bituminous IGCC reference plant, among other activities. While these efforts are still at relatively early stages, and not yet able to meet the demand for reliable baseload power at Dry Fork Station, they are important steps and demonstrate Basin Electric's commitment to responsible development of coal energy resources.*

ENV Comments #4 & 5

Building an IGCC unit, instead of the PC plant proposed by Basin Electric, must be considered as a part of the BACT analysis, because IGCC is an inherently lower-polluting production process, or a fuel cleaning technique, or an innovative fuel combustion technique within the definition of BACT, and would achieve lower emissions than those proposed for Dry Fork. ENV acknowledge that the BACT process cannot require a permit applicant to "redefine" the proposed source, but argue that IGCC would not constitute a redefinition of the proposed plant, and that some states are requiring IGCC be considered in the BACT process.

Response:

IGCC Would Totally Redefine the Proposed Plant, and Redefinition of the Proposed Project is not Required to be Considered Under BACT

IGCC is not an emission control technology for a PC plant. It would be a total and fundamental redesign and redefinition of the proposed PC plant that could not fulfill the basic needs and purposes for the proposed plant, and therefore is not required to be considered as part of the BACT analysis.

EPA guidance and Environmental Appeals Board decisions for more than twenty years have uniformly provided that a permit applicant cannot be required to redefine its proposed source as part of the BACT analysis. E.g., EPA NSR Manual at B.13 ("Historically, the EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives."); Prairie State EAB Decision at 27 ("We have specifically stated that 'EPA has not generally required a source to change (i.e., redefine), its basic design.'" (quoting In re Knauf Fiber Glass, GmbH, 8 E.A.D 121, 136 (EAB 1999).) (emphasis in original); In the Matter of Hawaiian Commercial and Sugar Co., 4 E.A.D 95, 99 (EAB 1992) ("EPA's PSD permit condition regulations do not mandate that the permitting authority redefine the source in order to reduce emissions." The Environmental Appeals Board rejected a petition to require the substitution of a fuel oil-fired combined cycle facility for a *proposed coal-fired power plant);* *In the Matter of Old Dominion Electric Cooperative Permit Applicant, 3 E.A.D. 779 (EAB 1992), 1992 EPA App. LEXIS 37, *31-32 ("Traditionally, EPA does not require a PSD applicant to change the fundamental scope of its project," n.38. The permit applicant was not required to consider natural gas in lieu of a PC plant.); In the Matter of Pennsauken County New Jersey, Resource Recovery Facility, EAB PSD Appeal No. 88-8 (November 10, 1988), at 10-11 ("The permit conditions that define these systems are imposed on the source as the applicant has defined it. . . . the conditions themselves are not intended to redefine the source. . . ." The Administrator rejected the claim that municipal waste should be co-fired with fuel and coal at power plants instead of burned in a municipal waste combustor). ENV argue that In re Hibbing Taconite Company, 2 E.A.D. 838 (EAB 1989) supports its claim, but in Hibbing the Administrator merely required the company, in its BACT analysis, to consider maintaining the status quo, which was burning natural gas, instead of switching to petroleum; no redesign was involved, nor was there an issue regarding the purpose of the operation.*

An IGCC plant employs a radically and fundamentally different way of generating electricity than a PC plant. In a PC plant, coal is combusted in a boiler to heat water and convert it to steam. The steam is piped to the steam turbine generator, which converts the steam's thermal energy into mechanical energy, and the steam turbine turns the generator to produce electricity. IGCC is more like a chemical plant, combined with a combustion turbine similar to those that use natural gas to generate electricity. These IGCC components have almost nothing in common with a boiler-based PC plant. In an IGCC plant, a cryogenic air separation unit provides oxygen for the gasification process, in which coal is heated and thermally converted (but not combusted) to a mixture primarily composed of hydrogen and carbon monoxide, referred to as synthetic gas (syngas). Impurities such as sulfur compounds, metals, ash and ammonia must be removed before the syngas is combusted in the combustion turbine, which is part of a combined cycle power block that generates electricity. Whereas the fuel in a PC plant is coal, the fuel in an IGCC plant is clean syngas. An IGCC pland does not, nor cannot, burn coal. More detailed descriptions of PC plants and IGCC plants, and flow diagrams illustrating the components and processes for each, are found in Exhibit 10, "Coal Power Plant Technology Evaluation for Dry Fork Station, November 1, 2005", prepared for Basin Electric by CH2M-Hill (2005 Technology Evaluation); and Exhibit 22, "A Comparison of PC, CFB and IGCC Technologies for Basin Electric Power Cooperative's Dry Fork Station" (2007 Technology Comparison).

As noted, the combined cycle power block in an IGCC plant is very similar to a combined cycle natural gas-fired power plant used to generate electricity. In fact, an IGCC power block can be designed to burn natural gas when the gasifier is not operating to provide syngas. EPA has specifically stated that a permit applicant is not required to construct a natural gas-fired turbine instead of a PC plant, because that would be redefining the source. EPA NSR Manual at B.13. ("For example, applicants proposing to construct a coal-fired electric generator, have not been required by EPA as part of a BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity)"). An IGCC power block, being essentially the same as a natural gas-fired turbine, is likewise not required to be considered as part of a BACT analysis. In fact, an IGCC unit is even more different from a PC plant than a combined cycle natural gas-fired plant, because it includes a chemically complex gasification plant in addition to a combined-cycle power plant. Therefore, to require consideration of IGCC would be a more extreme redefinition *of a proposed PC plant than was rejected by the EPA in the EPA NSR Manual. If substituting an IGCC plant for a PC plant is not a fundamental redefinition of the proposed source, it is difficult to imagine what might constitute a redefinition.*

The radical difference between an IGCC unit and a PC unit has lead EPA specifically to reject the claim that an IGCC unit must be part of the BACT analysis for a PC plant. In 2005, EPA determined that "the IGCC process would redesign the basic design" of an SCPC [supercritical pulverized coal] plant, and therefore, EPA "would not require an applicant to consider IGCC in a BACT analysis for an SCPC unit." Letter from Stephen Page, Director, Office of Air Quality Planning and Standards, U.S.E.P.A., to Paul Plath, E3 Consulting, December 13, 2005, Exhibit 23.[3]

Even ENV do not contend that Basin Electric should be required to redefine the proposed source. They argue, rather, that to build an IGCC plant instead of the proposed PC plant would not be redefining the source, but instead would fall within the BACT definition that calls for consideration of "production processes and available methods, systems and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of [a regulated] pollutant." The issue presented is where to draw the line between a "production process", "fuel cleaning" and "fuel combustion techniques", on one hand, and redefining the proposed source, on the other. ENV's claim that building an IGCC plant instead of a PC plant would not redefine the source surpasses the limits of credibility.

Of course, ENV's claim flies in the face of EPA's guidance that BACT does not require a natural gas-fired combustion turbine to be substituted for a PC plant, and that IGCC specifically is not part of the BACT analysis for a coal-fired plant. In addition, however, it is instructive to consider the recent decision of the Environmental Appeals Board in <u>In re Prairie State Generating Company</u>, 13 E.A.D ___, EAB PSD Appeal 05-05, (August 24, 2006). In that case, petitioners argued that Prairie States should have been required, as part of the BACT analysis, to consider using low-sulfur coal from Wyoming or Montana instead of high-sulfur local Illinois coal. However, the project was intended as a mine-mouth plant, that relied on using the local coal supply for more than 30 years as an inherent aspect of the project. Therefore, the EAB determined that Prairie State was not required to consider low-sulfur coal, "because it necessarily involves a fuel source other than the co-located mine, [which] would require Prairie State to redefine the fundamental purpose or basic design of its proposed Facility and . . . therefore, low-sulfur could appropriately be rejected from further BACT analysis at step 1 of the top-down BACT review method." Id., slip op. at 36-37.[4]

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[3] *ENV cite a 2004 EPA Region 8 letter regarding the Sevier Power Company project in Utah, in which EPA requested further information on costs to support the state's claim that IGCC was too costly. ENV Attachment 9. If Region 8 was implying that IGCC should be part of a BACT analysis, its views were inconsistent with the later 2005 letter from EPA headquarters.*

[4] *The Illinois Environmental Protection Agency (IEPA) did require Prairie State to submit an analysis of IGCC as a method of controlling emissions from the proposed facility. However, based on the information provided, the IEPA determined that "[w]hile various claims have been made that the technology is available for the proposed plant, they do not survive close scrutiny. While IGCC is expected to be the next generation of technology for coal-fired power plants and*

*To bolster the lack of current authority supporting their claim for IGCC, ENV cite a statement made on the floor of the Senate 30 years ago by Senator Huddleston, alluding to gasification being within the concept of BACT. ENV Comments at 12-13. However, a fuller look at Senator Huddleston's statements indicate his true intent was to promote the use of coal, and "not inhibit . . . continued development in making coal a clean burning acceptable fuel." He noted that "I believe everybody recognizes . . . that the central part of our energy effort has to be the greater utilization of coal." 123 Cong. Rec. S9434 (daily ed. June 10, 1977), 132 Cong Rec S9421 at *S9434 (LEXIS). The Senator's single sentence, to which ENV seek to give much weight, was spoken in the abstract, many years before there were any IGCC plants in existence, without any thought concerning what might be involved in an IGCC process and without any appreciation of what a radical change would be involved in substituting an IGCC plant for a PC plant. Senator Huddleston wanted to promote the use of coal, and help lower barriers that might hinder the growth of coal. Nothing in his statement indicates that hi reference to "gasification" contemplated IGCC. Further, floor statements by Senators cannot amend the clear language of a statute or distort its meaning. Barnhart v. Sigmon Coal Co., 534 U.S. 438, 457 (2002). Nothing in the text of the CAA indicates an intent to authorize redefinition of a source under BACT. BACT is, after all, intended as a means to evaluate control technologies, not as a means for EPA or state air agencies to determine national energy policy or select the means by which electricity will be generated. Nothing in Senator Huddleston's floor statement indicates an intent to so radically modify the concept of BACT. To give that much sway to the floor statement would empower an individual member of Congress to rewrite legislation by slipping a statement into the legislative record.*

In Prairie State, the EAB analyzed at length the relationship between what constitutes a redefinition of a source, and what is a "production process", "fuel cleaning" or "fuel combustion technique that comes within the BACT analysis. The Appeals Board rejected petitioners' assertion that what constituted redefinition depended solely on whether the switch to low sulfur coal would change the purpose of the project, stated in the broadest possible way—i.e., the production of electricity from coal. Id at 31. It found that redefinition can mean either a

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has been demonstrated by several projects supported by the United States Department of Energy (USDOE), it is still a developing technology that is not yet fully mature. IGCC technology is significantly more expensive and has not demonstrated the same level of dependability as traditional boiler technology. These factors are obstacles to commercial acceptance, i.e., financing, of the proposed plant with IGCC technology. It is not appropriate for the permit to require use of a technology by the proposed plant that is not yet sufficiently developed to be commercially accepted." IEPA Responsiveness Summary for Public Questions on the Construction Permit Application from Prairie State Generating Station, Application No. 01100065, April 2005, at 6, available at http://www.epa.state.il.us/public-notices/2004/prairie-state-generating-company/responsiveness-summary.pdf. Because the IEPA rejected IGCC the validity of considering IGCC at step 1 of the BACT process was not before the EAB and not decided by the EAB. The issue was whether the IEPA's Step 2 rejection of IGCC was valid, and the EAB held it was. If requiring the applicant to forego using local coal and instead transport low-sulfur coal from the West was a redefinition of the proposed project, it follows, a fortiori, that requiring Basin Electric to build an entirely different type of facility, using non-proven technology, that does not meet the need for baseload capacity, high availability and high reliability, certainly would be a redefinition of the proposed facility.

change in the basic purpose of a project, or in its basic design. Id. at 27. And it held that in determining what is the basic purpose or design of a project, and what would be a redefinition of the purpose or design, "the permit issuer looks to how the permit applicant defines the proposed facility's purpose or basic design in its application . . . " (Emphasis added) Id. at 28. See also, In the Matter of Pennsauken County New Jersey, Resource Recovery Facility, PSD Appeal No. 88-8, at 11 ("permit conditions . . . are imposed on the source as the applicant has defined it." (Emphasis added)). Responding to concerns that permit applicants might manipulate the definition of their projects so as to seriously limit consideration of pollution controls, the EAB made clear that neither the applicant's business or design could "preclude application of 'add-on controls,' including demonstrated and transferable technologies and innovative technologies", and that applicant's basic design must be "independent of air quality permitting" (and not intended to avoid emission control requirements). Id. at 33-34. "[T]he permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility, and therefore the permit issuer must discern which design elements are inherent to that purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emission reductions without disrupting the applicant's basis business purpose for the proposed facility." Id. at 30. Within the constraints of the project as defined, the permit issuer may "tak[e] a 'hard look' at whether the proposed facility may be improved to reduce its pollutant emissions." Id. at 34. In that hard look, it is appropriate to evaluate how "production processes" might be modified or how "fuel combustion techniques" might be applied to reduce emissions from the project—but that hard look cannot be used to redefine the project. The option to look at production processes, fuel cleaning and combustion techniques is subordinate to the proscription against redefining the source.

Basin Evaluated IGCC Technology in the Process of Planning and Designing Dry Fork, and Found it Would not Fulfill the Basic Need and Purpose for the Plant

Basin Electric did, in fact, consider whether IGCC might be a viable alternative to a PC plant during its planning process for Dry Fork Station. This was done, not as part of a BACT analysis, but rather as part of evaluating alternative technologies for generating electricity. That evaluation, "Coal Power Plant Technology Evaluation for Dry Fork Station", November 1, 2005, prepared for Basin Electric by CH2M-Hill, (2005 Technology Evaluation) is submitted herewith as Exhibit 10. Respecting IGCC, the evaluation concluded that "[t]he risk of installing [this] more costly technology, that has not been proven to be reliable and for which strong commercial performance guarantees are not available, is far too great for Basin Electric to take on for such speculative purposes." 2005 Technology Evaluation at 7.

Basin is developing Dry Fork Station to meet a rapidly growing demand and pressing need for additional electric power generation in its service area in Northeast Wyoming. Projections show that by 2015, demand for electric generation capacity from Basin Electric in that area will require 300 MW of additional capacity. Northeast Wyoming Generation Project, Project Justification and Support, Basin Electric Power Cooperative, Supplemental Analysis (July 2005) at 2. ("Project Justification and Support"). Executive Summaries for the Project Justification and Support, Initial Analysis and Supplemental Analysis, are submitted herewith as Exhibit 24. As noted in the Project Justification and Support, Northeast Wyoming is transmission-constrained, meaning that "there are major transmission constraints that limit the *ability to move power into the region," Supplemental Analysis at 5. "[T]he inability of the existing transmission system to serve [the increased demand for electricity] drives the need for additional generating capacity in Northeast Wyoming." Initial Analysis at 2. The high load factor and electrical demand "can best be served by a generation resource able to run at full capacity and continuously throughout the day and night, all year round. Generation facilities designed and capable of providing such high load factor electrical power are known as baseload sources. Baseload sources/units are designed to provide an optimal balance between the high capital/installation cost and low cost fuel, in order to give the lowest overall production cost; under the assumption that the unit will be heavily loaded (i.e. 80+% load factor) for most of its projected life." Initial Analysis at 3. Therefore, Dry Fork Station must have high availability to meet the demand, and the technology used to generate electricity at Dry Fork Station must be proven to be highly reliable.*

The 2005 Evaluation done by CH2M-Hill concluded that IGCC technology cannot meet these criteria. Dry Fork must be a baseload facility, with a minimum availability of 90%, and a minimum capacity factor of 85%. 2005 Evaluation at 1.[5] There are only four coal-based IGCC power plants currently operating in the world, two in the U.S. (the Polk plant in Florida and the Wabash plant in Indiana), one in Belgium (NUON Buggenum) and one in Spain (Puertollano). The average annual plant availability at Polk for 2001 to 2003 was 73%. Id. at 4. Plant availability for the three years of data reported for Wabash (1997 to 1999) averaged 48%. Id. Plant availability for Puertollano from 2001 to 2003 averaged 58%. Id. at 32. The capacity factors for the last three years of data reported for the Polk and Wabash IGCC units (1999 to 2001) were calculated to be 70% and 38%, respectively. Id.

The performance of existing coal-based IGCC plants has improved since the 2005 Evaluation was prepared, but still falls well short of the availability required at Dry Fork Station. From 2004 to 2006, the average annual plant availability at Polk was 73%. Plant availability for the last three years of data reported for Wabash (2003, 2005 and 2006 – the plant was not in operation during 2004 due to economic reasons) averaged 72%. The Nuon Buggenum IGCC plant, which has been in service the longest of the coal-based IGCC plants, has never achieved 80% availability in its 12 years of operation, and plant availability for Puertollano has never been above 66%. None of these coal-based IGCC plants has ever achieved its design target of 85% availability. Only the Polk plant has reached 80% availability (in one year), although it has not maintained that level. For additional discussion of current IGCC plant availability performance, see the 2007 Technology Comparison at 7-9, Exhibit 22.

The 2005 Technology Evaluation further emphasized there has been no viable commercial demonstration of IGCC technology using sub-bituminous coal, which will be used at Dry Fork, or operated at the 4,250 foot elevation of Dry Fork. "[L]ittle operating experience exists regarding IGCC plants consuming sub-bituminous coal. None of the four commercial-scale IGCC plants currently operating in the world consume sub-bituminous coal; all four

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[5] *The Laramie River Station near Wheatland, Wyoming, a PC plant operated by Basin Electric, has averaged a plant-wide availability over the past six years of 91.4%, with units in some years achieving as high as 99.4%. A Comparison of PC, CFB and IGCC Technologies for Basin Electric Power Cooperative's Dry Fork Station, CH2M Hill, June 2007, Exhibit 22, at 7-8.*

consume either bituminous coal or petroleum coke (citation omitted). One commercial-scale IGCC plant, the Dow Chemical/Destec LGTI project, was previously operated on sub-bituminous coal; however this project was supported with guaranteed product price support offered by Dow Chemical and the U.S. Synthetic Fuels Corporation, and was promptly shut down when the price support expired (citation omitted). . . . It is clear that the majority of operating experience for coal-based IGCC plants is with bituminous coals and that further study is required to prove the technical and economic feasibility of IGCC operation with sub-bituminous coals, and in the context of published cost data, it would be irresponsible to assume that an IGCC plant consuming sub-bituminous coal could match the performance of an IGCC plant consuming bituminous coal." Id. at 44.

"None of the commercial systems constructed to date have operated at the almost 5,000 foot altitude of the proposed new unit. This altitude will result in de-rating of the combustion turbines, and would thus require a larger combined cycle component of the IGCC system to produce the same output as a system constructed at low elevation. This would further degrade IGCC economics at the NE Wyoming project." Id. at 45.

"The longer time for startup/shutdown, and inflexibility of system output for load-following, of an IGCC system versus a PC system creates additional challenges for utilities. Startups have reportedly required up to 70 hours, and flaring of treated and untreated syngas during these startups can create substantial additional air emissions, which are not typically included in IGCC emission estimates." Id.

"IGCC systems have relatively low availability, due in large part to frequent maintenance required for gasifier refractory repair. This creates the need for redundant gasifier systems, or burning pipeline natural gas as a backup fuel which further increases the system capital and operating costs and operating complexity." Id.

Only three of six IGCC technology leaders responded to an IGCC Feasibility Study Request for Proposal (RFP) sent by Basin Electric in February, 2005. "All three of the proposals received were deemed unresponsive; they did not specify the terms and conditions which would be proposed for this type of commercial offering and did not describe the financial backing which could be offered for such guarantees and warranties, as specified in the RFP. All parties required further studies, additional money, and more time to get to a point where some of the performance and commercial information requested would be available." Id. at 5.

"There is a lack of acceptable performance warranties/guarantees for commercial IGCC offerings. The reliability of the technology is an important factor given that this plant is intended for baseload generation and represents approximately 10 percent of the Basin Electric generation portfolio. In the business of building large scale generation resources, it is standard practice for suppliers to offer plant performance guarantees that are specific and precise in nature and are a direct reflection of their confidence that the plants will perform as desired. The providers of IGCC technology were unwilling to provide such assurances, greatly increasing the risk and potential future costs should this option be chosen and fail to perform to expectations. This is a clear indication of how much more development this technology requires before it can be considered to fill the role of reliable, large-scale generation." Id.

"At this time, IGCC technology is not fully developed, and it is not technically feasible in the context of a BACT analysis. According to George Rudins, United States Department of Energy (DOE) deputy assistant secretary for coal, 'Right now, there is not a single company producing a turnkey IGCC power plant, so you have components sold by different companies, and that increases the challenge.' (Citation omitted) . . . . Because the burden for technological development rests on the project developer, the technology cannot be truly considered commercially available. . . . Basin Electric is not aware of any vendors offering guarantees on the air emissions from either the combustion turbine or tail gas incinerator components for an IGCC system consuming sub-bituminous coal; this problem is a function of the fact that developers must integrate systems offered by different vendors." Id. at 43.

"A case in point regarding the technological and commercial terms challenges is the recent Pinon Pine project in Storey County, Nevada. . . .The project was funded 50 percent by the DOE, and benefited from the technological expertise of the DOE. Despite the expertise available to the project, the plant never achieved steady state operation, and as such, environmental and economic performance of the project could not be evaluated. Eighteen unsuccessful attempts were made to start up the gasification system; each subsequent startup attempt was not begun until the cause for the previous malfunction was resolved (citation omitted). Technical problems with the system included failure of HRSG components, unacceptable temperature ramps in the gasifier, which caused failures in gasifier refractory, a fire in the particulate removal system, and multiple other problems with the particulate removal system. While many lessons were learned from development of the plant, and these lesson may lead to improved plant design in the future, the plant certainly could not be considered a technological success." Id. at 43-44.

For all of these reasons, the results of the CH2M Hill evaluation for IGCC technology were bleak. IGCC was found to be too unreliable and not sufficiently available to meet the need at Dry Fork Station for baseload power at or above 90% availability and 85% capacity factor. There had been no meaningful experience with IGCC using sub-bituminous coal, or with IGCC at a 4,250 foot elevation, so one could not count on IGCC at Dry Fork performing even as well as the two unreliable demonstration plants that used bituminous coal at lower elevations. No vendor was prepared to offer meaningful guarantees of performance or air emissions, all wanted more time and more money to do studies, and none were prepared to offer a turnkey package such as those typically available for PC plants. With all of these red flags, it would have been imprudent for Basin to have chosen IGCC as the generation technology to fulfill the purposes of the Dry Fork plant.

In light of the total and extreme differences between PC technology and IGCC technology, and in the absence of any evidence that IGCC was likely to be capable of meeting the performance needs at Dry Fork Station, the only reasonable conclusion is that IGCC would be a redefinition of the proposed PC plant, and therefore is not a control technology that would have to be considered among the potential technologies at Step 1 of the BACT process.

Updated Information Regarding IGCC Technology Continues to Show it is Not Sufficiently Available, Reliable or Commercially Demonstrated to Fulfill the Purpose and Need for the Dry Fork Station

In 2005, based on the best information and analysis available to it, Basin Electric selected PC as the electric generation technology that could meet the all the criteria for Dry Fork, including high availability, reliability, commercially demonstrated and affordable cost. Based on that selection, Basin Electric has spent the best part of two years designing, developing and permitting a PC plant. If the company were required to build an IGCC plant instead, it would be impossible to meet the January 1, 2011 target date for commencement of operations, and therefore its ability to meet the growing demand for electricity in Northeast Wyoming would be severely compromised. Switching to an entirely new generating technology is not like switching from one type of add-on control technology to another. Even if we were to ignore the inability of IGCC to meet the purpose and need for this project, and even if we assumed Dry Fork could be a viable project as an IGCC plant, switching to IGCC would require starting the project from scratch, an entire redesign, and a new permitting process for the different facility, and therefore would result in years of delay. Having made an informed choice concerning the appropriate generation technology to meet the needs, based on in-depth evaluation of the alternatives, Basin Electric should not have to go back to square one at this late date.

That said, Basin Electric requested CH2M Hill to prepare an updated comparison between PC and IGCC technology. CH2M Hill's report is titled "A Comparison of PC, CFB and IGCC Technologies for Basin Electric Power Cooperative's Dry Fork Station", June 26, 2007, (2007 Technology Comparison) and is attached as Exhibit 22.

The 2007 Technology Comparison reaffirms the analysis reported in the 2005 Technology Evaluation. IGCC is not yet a proven or commercially available technology and will not meet the purpose and need for the Dry Fork Project. Vendors are not offering IGCC turnkey projects or guarantees similar to those available for PC plants. IGCC has not been demonstrated using sub-bituminous coal or at elevation. The capital costs of an IGCC plant are much higher than for an IGCC plant and electricitiy generated by such a plant is much more expensive than with a PC plant. And, of course, IGCC is a radically different design and technology than a PC plant.

"An IGCC plant is more akin to a chemical plant, and has little in common with the combustion, steam generation and air pollution control (APC) systems utilized in PC and CFB boilers." Id. at 1. "Where PC and CFB boilers are based on the Rankine thermodynamic cycle (steam production and use in a steam turbine), IGCC uses the Brayton cycle, based on firing a fuel, syngas, in a rotating combustion turbine. These two thermodynamic cycles are completely different." 2007 Technology Comparison at 5.

"In contrast [to PC plants], all four of the coal-based IGCC plants worldwide experienced very low availability during their early years of operation. The availability improved after design and operation changes were made to each facility; however, their current annual availability is still much lower than what they were designed for, as well as being far lower than what can be achieved with PC and CFB technology." Id. at 8.

"A key example of this is the Pinon Pine IGCC project . . . . This was the third coal-based plant planned for construction and operation under the DOE Clean Coal Technology Program. Unfortunately, this technology and the project failed due to problems with the basic design and performance of the gasifier, as well with syngas cleanup system. It was never able to maintain consistent operation on syngas, and was shut down and abandoned." Id. at 9.

A new IGCC configuration, with two gasifiers, "is expected to provide for higher availability, [but] it is not yet proven in commercial service and won't be until the first new IGCC plants start operation in another four to five years." While a third spare gasifier could be added, this adds substantial cost and "[e]ven with a spare gasifier, it is not yet known if IGCC will be able to match the high availability of PC and CFB technologies." Id.

Despite IGCC vendors having stated they plan to offer turnkey systems and performance guarantees, they have failed to do so. Examples are Duke Energy Indiana's Edwardsport Plant, where Duke expected to receive appropriate guarantees, but it turned out that a lump sum turnkey contract was not a viable option. Id. at 11. In June, 2007 Tondu Corporation announced it was cancelling its proposed 600 MW IGCC plant in Corpus Christi, Texas, due to high cost. Even when turnkey contracts become available with performance guarantees, they likely will not be available for small plants (smaller than the 600 MW "reference plant" vendors are working on) burning sub-bituminous coal. Id. at 11-12. Both of the two 600 MW demonstration IGCC plants intended to use sub-bituminous coal have run into difficulties and delays, and it is not known when they might go forward. "The cost, availability, and efficiency of IGCC designed for use with PRB coal is not yet known, nor will it be known for another five to six years." Id. at 12-13.

"The existing coal-based IGCC plants required significant government subsidies. Although they have been in operation as long as 12 years, these concerns have not changed. There is a continuing need to offset IGCC capital costs with government subsidies, loan guarantees, and/or tax credits. Almost all of the IGCC plants planned at this time are receiving direct co-funding or tax credits by their specific states or under the DOE's Clean Coal Power Initiative, have been awarded tax credits under the Energy Policy Act of 2005, or are applying for a loan guarantee under that Act." Id. at 13.

Although IGCC vendors have stated the capital cost of a 600 MW net IGCC reference plant designed for use with eastern bituminous coal would be about 25% greater than that of PC technology, "recent cost data provided in public submittals and announcements has shown that this 25% premium is far low. The costs for an IGCC plant, using PRB at high altitude, is not yet known; however . . . it will be much higher than for a plant designed for using eastern bituminous coal at low altitude." Id. at 14.

Finally, due to the lower availability of IGCC technology, to try to attain higher availability it is necessary to use natural gas as a backup fuel when the gasifier(s) are not operating. The use of natural gas as a backup fuel "requires that a natural gas pipeline be included in the design, permitting and construction of an IGCC plant. The pipeline must be capable of providing sufficient natural gas for use at full load by both combustion turbines. This is a significant additional capital cost which is not included in the economic analysis [set forth in *the 2007 Technology Comparison]. It would further increase the cost spread between IGCC and PC, in both capital cost and operating costs. . . ." Id. at 15.*

As a result of all these factors, "IGCC technology is judged as not being capable of fulfilling the need for new coal-based generation, as it does not meet the requirements for a high level of availability and long-term, cost-effective power generation." . . . "[T]he technology is still in development, and is not yet commercially proven at large scale, even on eastern bituminous coal. No utilities have been able to obtain sufficient guarantees on cost, schedule or performance on IGCC reference plants. Further, IGCC technology is not commercially available at the 368 MW size needed for this project, either on eastern bituminous or PRB coal." Id. at 18-19.

<u>*Requests by a Few States that Permit Applicants for PC Plants Evaluate IGCC do not Support the Argument that IGCC Should be Required in the Dry Fork BACT Analysis*</u>

To support its claim that BACT evaluations must include IGCC, ENV cites four projects in four different states where it says the state air regulatory agencies required permit applicants for a coal-fired power plants to consider IGCC as part of the BACT analysis. As it turns out, none of these four states issued a permit requiring that an IGCC plant be built instead of a coal-fired plant. Three states permitted coal-fired plants, and in the fourth the project proponent decided not to pursue the project.

We question whether, in fact, states have the discretion and authority to require IGCC in lieu of a PC plant. The NSR Manual, after noting that EPA has not required applicants to build natural gas-fired plants instead of coal-fired plant under BACT, goes on to say that "this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire." The intent of this statement is somewhat obscure, but some might argue the language means a state could require a source to be redefined under BACT. Perhaps states have discretion to open up consideration of production processes more than EPA might, but we submit that states do not have unfettered discretion to the extent they can require redefinition of a source—that would be inconsistent with the uniform EAB holdings that redefinition is not required. A state might have discretion and authority to adopt specific legislation or regulations calling for or encouraging the use of IGCC, as part of an effort to limit greenhouse gas emissions. But if its PSD rules and BACT definition are essentially the same as the federal definition, it is difficult to see how a state could legitimately interpret those rules in a way that directly contradicts EPA's interpretation. If states do have discretion , the case for not using that discretion to require IGCC as a control technology is compelling, as explained herein.

Following are specifics concerning each of the four state agency examples cited by ENV.

<u>*Illinois—Indeck-Elwood.*</u> *ENV attach a March 2003 letter from the Illinois EPA (IEPA) in which the state agency requested additional material regarding IGCC as a possible emission control technique under BACT. ENV Attachment 3. However, after receiving information from Indeck-Elwood, the IEPA determined that IGCC was still a developing technology that was not available. "While various claims have been made that the technology is available, they do not survive serious scrutiny. While IGCC is expected to be the next generation of technology for*

coal-fired power plants, it is still a developing technology that is not yet mature. It is not appropriate for the permit to require use of a technology by the proposed plant that is not yet sufficiently developed to be commercially accepted." IEPA, Responsiveness Summary for Public Questions and Comments on the Construction Permit Application from Indeck-Elwood LLC, Application No. 02030060, October 2003, (Indeck-Elwood Responsiveness Summary) at 3, available at http://yosemite.epa.gov/r5/il_permt.nsf/1aa55bd5a0796efd862566b4005a68db/24e3d77164557e1b85256d02004c211e/$FILE/Indeck%20Responsiveness%20Summary.pdf. The agency went on to say that it had "considered whether the proposed plant should use gasification technology (Integrated Gasification Combined Cycle or IGCC) and has required Indeck to conduct a detailed evaluation of the feasibility of using this technology. The Illinois EPA concluded that gasification is still a developing technology for power generation. As a result, the uncertainty about the performance and cost of this technology would prevent the plant from being developed with gasification technology. Given these findings, the Illinois EPA does not have the authority to order Indeck to use coal gasification technology at the proposed plant." Id. at 5-6. The permit actually issued for the Indeck-Elwood plant seven months after the letter cited by ENV, approved construction of a 660 MW CFB boiler, with emission limits for most pollutants higher than those proposed for Dry Fork. Construction Permit—PSD Approval NSPS NESHAP Emission Units, Indeck Elwood, October 10, 2003, available at http://www.illinois.sierraclub.org/news/101003permit.doc.

<u>Georgia--Longleaf Energy Station.</u> ENV attach a March 6, 2002 letter from the Georgia Department of Natural Resources, Environmental Protection Division (EPD) to Longleaf Energy Associates regarding its application for a PSD permit for the Longleaf Energy Station. ENV Attachment 5. The letter says that Longleaf should discuss IGCC technology and explain why it elected to propose a coal-fired plant instead. Again, however, when it issued the permit for a coal-fired boiler, EPD made it clear that IGCC would involve a redefinition of the plant. "IGCC is a physically and chemically distinct method of producing electricity that cannot be compared to the PC fired boiler proposed at the Facility without redefining the source. Neither federal law nor Georgia law require the consideration of technologies that would redefine the proposed source." Prevention of Significant Air Quality Deterioration Review Of the Longleaf Energy Associates, LLC Longleaf Energy Station to be located in Early County, Georgia FINAL DETERMINATION SIP Permit Application No. 15846 May 2007 (Final Determination), at 33, available at http://www.georgiaair.org/airpermit/psd/dockets/longleaf/permitdocs/0990030fd.pdf. The permit was issued on May 14, 2007 for construction of a 1200 MW coal-fired plant.

<u>Montana—Roundup Power Project.</u> ENV assert that the Montana Board of Environmental Review (MBER) found that IGCC must be considered as an available technology in the BACT review for a coal-fired plant, and specifically quotes a statement in the MBER's Findings of Fact and Conclusions of Law that the Department of Environmental Quality "should require applicants to consider innovative fuel combustion techniques in their BACT analysis." ENV Comments at 23. However, in its Findings of Fact and Conclusions of Law (ENV Attachment 8), the MBER found that "in reviewing the BACT analysis for the Project, the Department gave substantial consideration to IGCC and CFB combustion technologies. The record supports the determination that these technologies are not BACT." ENV Att. 8 at 18. Although the decision of the Board stated that in the future the Department should require applicants to consider

innovative fuel combustion techniques (a phrase expressly included in the definition of BACT), it pointedly did not state that IGCC should be considered as BACT.

<u>New Mexico—Mustang.</u> As noted by ENV, the New Mexico Environment Department, Air Quality Bureau (AQB) required Mustang Energy to include IGCC in its BACT analysis (ENV Attachment 6), and subsequently required Mustang to revise its BACT-inclusive analysis as incomplete (ENV Attachment 7). Unlike the three other states cited by ENV, New Mexico did not, subsequent to its letter of August 29, 2003 (Attachment 7), reject IGCC as BACT because it would redefine the project or on other grounds. The Sierra Club reports that Peabody Coal, the parent of Mustang Energy, withdrew its application in September of 2006, and notes that Peabody and the AQB could not agree on whether IGCC was technically or economically feasible. Sierra Club, Coal Rush Plants, available at http://www.sierraclub.org/environmentallaw/coal/plantlist.asp. Although New Mexico did not issue a permit requiring IGCC as BACT, it apparently has not changed its initial view that IGCC should be considered in the BACT analysis. This view, however, is distinctly the minority view.

Therefore, upon closer examination, ENV got it wrong in three of the four states they cited to support the claim that "state decisions validate the plain language of the definition of BACT . . . " Although these three states (Illinois, Georgia and Montana) initially asked project proponents to provide information about IGCC, once they examined the facts they concluded that IGCC was not BACT or IGCC would redefine the source. Basin Electric has provided information to the WDEQ regarding IGCC which explains in detail that IGCC would fundamentally redefine the proposed source, and on that basis urges the WDEQ to follow the example of these three states and reject the claim that IGCC must be analyzed in the BACT process.

<u>On Both the Law and the Facts, IGCC Would Redefine the Proposed Project and is not Required to be Included in the BACT Analysis</u>

Even ENV does not appear to dispute the unassailable principal that a permit applicant cannot be required, as part of the BACT analysis, to redefine its proposed project. The only point of debate is whether requiring IGCC would redefine a proposed PC plant. As held in the Prairie State case, it is the project proponent that defines the project and, as long as that definition is based on reasons other than air permitting reasons, the proponent cannot be required to totally revamp and redefine what it proposes. Given that a permit applicant for a coal-fired power plant cannot be required to build a natural gas-fired plant instead, it follows, <u>a fortiori</u>, that it cannot be required to build an IGCC plant instead. For the many reasons described above, an IGCC plant would be a totally different plant than a PC plant, and at this time IGCC does not have the demonstrated reliability, availability, or baseload capacity to meet the needs of Basin Electric's customers in Northeast Wyoming. Contrary to ENV's claims, IGCC is not an emission control technology at all, but rather a totally different electrical generation technology. To treat IGCC as an available emission control technology would be to subvert the purpose and intent of the BACT requirement.

IGCC Is Technically Infeasible at Dry Fork and Would be Rejected at Step 2 of BACT

Even if we assume for purposes of discussion that IGCC would not redefine the Dry Fork project and should be deemed an emission control technology to be considered in the BACT analysis, it should be rejected as technically infeasible at Step 2 of the BACT process. To be technically feasible, a control technology must be both "applicable" and "available".

"A control technique is considered available . . . if it has reached the licensing and commercial sales stage of development. A source should not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type." NSR Manual at B.18. As explained above, although there are two operating IGCC plants in the United States that use bituminous coal, there are no plants that use sub-bituminous coal or that operate at a 4,250 foot elevation, and both of these factors have potentially large impacts on IGCC plant performance. The two operating plants, moreover, are demonstration plants that were with government subsidies. Moreover, Basin Electric did not receive a single reply to its six requests for proposals for an IGCC plant that was responsive to Basin's needs and criteria. Unlike vendors of PC plants, who routinely submit turnkey proposals with significant performance guarantees and substantial financial backing, vendors of IGCC equipment do not offer anything close. An IGCC plant at Dry Fork Station would be an experimental project—the first IGCC plant to use sub-bituminous coal at 4,250 feet elevation—with the attendant risks regarding performance failures, operational problems, cost overruns, etc. IGCC is not commercially "available" for purposes of BACT. Indeed, the Piñon Pine demonstration project in Nevada used western sub-bituminous coal and was closed down after 3 years without ever having operated successfully for more than 24 hours.

A control technique is "presumed applicable if it has been or is soon to be deployed . . . on the same or a similar source type. . . . For process-type control alternatives the decision of whether or not it is applicable to the source in question would have to be based on an assessment of the similarities and differences between the proposed source and other sources to which the process technique has been applied previously." EPA NSR Manual at B.18-.19. This makes clear that for a control technique to be applicable there must be a reasonable precedent where the technique has been used in similar circumstances. There is no precedent demonstrating that IGCC will meet the fundamental purpose and need for Dry Fork Station; no design for IGCC has been proven successful using sub-bituminous coal at 4,250 fee elevation; and no vendor could be found to build an IGCC plant on terms that did not expose Basin Electric and its members to huge risks. Under the circumstances, IGCC is not "applicable" for purposes of BACT.

"Vendor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique and could contribute to a determination of technical feasibility or technical infeasibility, depending on circumstances." NSR Manual at B.20. EPA notes that a vendor guarantee alone does not mean a control option will work, and the lack of a guarantee does not necessarily mean a control option is infeasible. For Dry Fork Station, taking into account the experimental nature of IGCC, especially with sub-bituminous coal and at 4,250 feet elevation, the lack of vendor guarantees speaks volumes about the absence of any assurance

that IGCC can do the same reliable steady job as a PC plant to meet the needs of Basin Electric customers.

To find that IGCC is technically feasible for application at Dry Fork Station would be to ignore the overwhelming lack of any evidence that IGCC can be counted on to do the job. It is an evolving technology, and may in time be improved and demonstrated to be a reliable method for generating electricity. In other places and other circumstances, the future potential for IGCC has emboldened companies to propose IGCC projects, and take the attendant risks. Many of these proposed projects continue to be subsidized by the government, and others have encountered problems with large increases in projected costs, resistance from state public utilities commissions, or otherwise. Hopefully, some of these projects will succeed and advance the state of the art. However, given the need for demonstrably reliable electricity to meet growing demand, Northeast Wyoming in 2007 is not the place for such an experimental or risky venture.

<u>*IGCC as Demonstrated in Practice Is Not the Most Effective Control Technology and Would be Rejected at Step 3 of BACT*</u>

BACT is based on a case-by-case analysis and requires the lowest emission limits that are achievable in practice for regulated pollutants. While there is a great deal of optimism about emission levels that might be achieved with the next generation of IGCC, it is important to recognize that such performance is still aspirational and based on engineering expectations, rather than what has been demonstrated in practice. The levels cited by ENV and NPS are primarily levels from air permit applications and draft permits; these emission rates have not been achieved by operating facilities. In contrast, there is a long history of operating experience for PC plants, including plants operating on sub-bituminous coal, and estimates of emissions performance for applicable control technologies are very reliable. The proposed permit limits for Dry Fork Station are based on a rigorous BACT analysis.

In support of their argument that IGCC is the "top ranked" technology, ENV provide a table comparing proposed emission rates for Dry Fork Station to the proposed permit for the 630 MW Taylorville Energy Center in Christian County, Illinois. Although a final permit for the Taylorville Energy Center IGCC project was issued in early June, the project still requires legislative action guaranteeing its ability to sell at cost-based rates to Illinois utilities, before it will go forward. <u>See, e.g.,</u> "Tenaska obtains Illinois clean-coal plant permit," June 6, 2007, available at http://www.cleancoalillinois.com/news-070606-reuters.html, ("Construction could begin this year in Christian County in central Illinois, if Tenaska can obtain favorable legislation. . . . The next hurdle needed to advance the project is a change in state law to allow Illinois utilities to sign long-term contracts for power"). In the words of the project developer, "legislation is needed to make the Taylorville Energy Center a reality." Illinois EPA Press Release, "Gov. Blagojevich announces landmark air permit for clean-coal gasification power plant in Taylorville," June 5, 2007, available at http://www.illinois.gov/PressReleases/ShowPressRelease.cfm?SubjectID=1&RecNum=6017.

It remains a question if and when the Taylorville Energy Center will actually become a reality, let alone whether it will be able to achieve permitted emission levels in practice. Thus, even if the BACT process required consideration of IGCC, the Taylorville figures do not *establish a reliable basis for determining what emissions limits can be achieved. "[A] permit issuer may appropriately consider, as part of its BACT analysis, the extent to which available data in the record evidence the ability to consistently achieve certain emissions rates or control effectiveness of the selected technology or pollution control method."* Newmont EAB Decision at *15. Accordingly, the EAB has held that "a permit issuer's rejection of a more stringent emissions limit based on the absence of data showing that the more stringent rate has been consistently achieved over time is not a per se violation of the BACT requirements." Id.*

The actual emissions performance at Polk Power Station and Wabash River IGCC facilities, the only two operating IGCC facilities in the United States, further underscores the gap between projections for future IGCC projects, and what has been achieved in practice to date. Table 4 contains a summary of NO_x and SO_2 emission rates achieved in practice at Polk and Wabash River.

Table 4

Year	Polk Power Station IGCC		Wabash River IGCC	
	NO_x Lb/MMBtu	SO_2 Lb/MMBtu	NO_x Lb/MMBtu	SO_2 Lb/MMBtu
1996	0.15	0.135	---	---
1997	0.12	0.220	0.15	0.266
1998	0.10	0.224	0.14	0.167
1999	0.09	0.180	0.15	0.132
2000	0.10	0.146	0.14	0.173
2001	0.10	0.153	0.17	0.143
Source: Nevada Response to NPS Comments, citing Sargent & Lundy, LLC, Intermountain Power Unit 3, Generating Technology BACT Evaluation, July 3, 2003 (Revised Nov. 26, 2003) Exhibit 13.				

The permit limits proposed for Dry Fork Station are lower for both NO_x and SO_2. A more recent summary of environmental performance for Wabash River indicates that those figures are getting lower, with SO_2 "consistently below" 0.1 lb/MMBtu of coal input and with the plant meeting the 0.15 lb/MMBtu NO_x requirement for ozone non-attainment areas. See http://www.clean-energy.us/projects/Wabash_indiana.htm. However, these levels are still higher than the proposed Dry Fork Station permit. Wabash River has achieved emissions for PM equivalent to the Dry Fork Station limit of 0.012 lb/MMBtu, and lower CO emissions, at 0.05 lb/MMBtu (compared to 0.15 lb/MMBtu for Dry Fork).

Furthermore, because BACT is a case-by-case determination, expectations related to the performance of a technology in one setting cannot be imported by "direct translation" from one facility to another, but rather "must also reflect consideration of any practical difficulties associated with using the control technology." Newmont EAB Decision *at 17. The NSR Manual provides, "Manufacturer's data, engineering estimates and the experience of other sources provide the basis for determining achievable limits. Consequently, in assessing the capability of the control alternative, latitude exists to consider any special circumstances pertinent to the specific source under review, or regarding the prior application of the control alternative." EPA NSR Manual at B.24. The 630 MW Taylorville Energy Center will utilize local Illinois supplies of bituminous coal. Not only does the unproven nature of the Taylorville Energy Center permit limits make them unreliable as a basis for BACT, there is additional reason to doubt whether they would be achievable in practice under the particular conditions at Dry Fork Station, which will operate on a sub-bituminous PRB coal supply, at high elevation, and at a non-standard 385 MW size.*

Table 5 provides a summary comparison of emission rates proposed in the Dry Fork Station draft permit, an estimate of BACT for demonstrated IGCC technology, and an estimate of BACT for "next generation" IGCC technology.

Table 5

Pollutant	PC (Dry FGD and SCR) (lb/MMBtu)	Demonstrated IGCC* (MDEA Gas Treatment/no SCR) (lb/MMBtu)	Projected IGCC** (MDEA Gas Treatment/no SCR) (lb/MMBtu)
SO_2	0.08	0.170	0.025
NOx	0.05	0.076	0.057
PM10	0.012	0.013	0.0063
CO	0.15	0.035	0.036
VOC	0.0037	0.0017	0.001

* Figures based on PSI Energy Wabash River Station and TECO Polk Power Station. *See* 2007 Technology Comparison at 3.
** 2007 Technology Comparison at 10.

Table 5 shows emissions performance for PC at Dry Fork Station will be comparable to (and in some cases better than) that of currently demonstrated IGCC performance. As noted throughout these comments, despite optimism regarding the future promise of IGCC, the ability to reliably achieve improved emission rates has not been demonstrated in practice. Just as there is uncertainty regarding IGCC's ability to deliver reliable, high availability, baseload power, *there is uncertainty about whether IGCC would be able to meet the next generation emissions targets in the Taylorville permit. Even if WDEQ were required to evaluate IGCC as part of the BACT analysis, the Taylorville Energy Center (or other next generation IGCC projects without operating experience) would not provide an appropriate model for BACT limits.*

<u>Consideration of Energy, Environmental, and Economic Effects Would Eliminate IGCC at Step 4 of Any BACT Analysis.</u>

If IGCC were ranked as a control technology in Step 3 of a BACT analysis, demonstrated performance of currently operating IGCC technology would not provide improved performance over a state-of-the-art PC configuration for most regulated pollutants, and therefore would be eliminated at Step 3. In the future, IGCC is expected to provide improved emissions performance, but those emission rates have not been demonstrated in practice, and do not currently have a performance record that would justify selection of IGCC as BACT. However, assuming (despite the lack of operational experience) that modeled emission rates for IGCC could be achieved, IGCC would be eliminated at Step 4 of the BACT process, due to its economic effects.

Step 4 of the top-down BACT process considers the control technologies identified at Step 1, found technically feasible at Step 2, and ranked at Step 3, and considers the energy, environmental, and economic impacts in order to arrive at the final level of control. See EPA NSR Manual at B.8. The purpose of Step 4 is to validate the suitability of the top control option for selection as BACT, or provide clear justification why the top candidate is inappropriate as BACT. Id. at B.26. Even if it were assumed that the emission rates projected for next generation IGCC could be reliably attained in practice, the collateral impacts of IGCC—in particular the economic impacts—would prevent its selection as BACT.

<u>Economic Effects Would Eliminate IGCC as BACT</u>

There is a significant cost premium associated with building IGCC. For the Dry Fork Station project, this premium is likely to be at least 30% over the total installed capital costs for a PC plant. IGCC technology providers have estimated that the cost premium for IGCC technology is 25%, and hope to reduce that penalty to around 10% through the development of an IGCC reference plant. However, recent experience demonstrates that the 25% premium is too low, and furthermore, technology providers are not yet willing or able to offer a turnkey project or other comprehensive commercial guarantees. Recent examples of these trends are summarized in the 2007 Technology Comparison at 14-15, Exhibit 22.

Even if an IGCC reference plant offering were available, Basin Electric would not be able to take advantage of it for Dry Fork Station, because the reference plant will be designed for low elevations and eastern bituminous coal. Costs would be further increased due to the smaller, non-standard 385 MW size of Dry Fork Station, which is not compatible with the standard 2-by-2-by-1 configuration of the reference plant. Dry Fork Station would also incur additional capital and operating costs due to the need to use natural gas as an alternative fuel to ensure 90% plant availability. In light of the particular circumstances of the Dry Fork project, a 35% cost premium for IGCC over PC is a conservative estimate.

Table 6 shows the incremental cost per additional ton of pollutants removed if IGCC were viewed as a "control technology" for PC in the BACT process.

Table 6

Factor	PC	IGCC
Total Installed Capital Costs	$ 1,350,000,000	$ 1,755,000,000
Total Fixed & Variable O&M Costs	$ 24,900,000	$ 49,100,000
Total Annualized Cost	$ 113,600,000	$ 164,400,000
Incremental Annualized Cost Difference: PC versus IGCC	-	$ 50,800,000
Incremental Tons Pollutants Removed: PC versus IGCC	-	2,543
Incremental Cost Effectiveness per Ton of Additional Pollutant Removed: PC versus IGCC ($/tpy removed)	-	19,981
Source: 2007 Technology Comparison at 23 (Exhibit 22).		

When analyzing IGCC as a "control technology" for PC, 2,543 additional tpy of NO_x, SO_2, CO, VOC, and PM_{10} (filterable) are removed at an annualized cost increase of $50,800,000, or $19,891 per additional ton removed. Due to the substantial incremental cost of emissions control for IGCC, the economic effects provide a clear justification why IGCC would be inappropriate as BACT.

<u>Energy Impacts</u>

Substituting IGCC for PC generation technology would have negative energy impacts for Dry Fork Station. Due to reliability concerns associated with IGCC, a baseload plant like Dry Fork Station would require an alternative fuel, such as natural gas, to maintain high availability in the event the gasifier were unavailable. This is a direct energy penalty associated with IGCC that is not associated with PC technology. At the Dry Fork Station, a natural gas pipeline and related facilities would be required to make natural gas available.

In addition, an IGCC facility operating at the Dry Fork Station site would be affected by significant derating, due to the altitude. In order to operate an IGCC plant at high elevation, the syngas fuel feed must be reduced to compensate for the thinner air, resulting in lower combustion turbine output. This also reduces the amount of heat recovered and transferred to the steam turbine. Therefore, energy impacts would weigh against selection of IGCC if it were considered in the BACT process.

Other Environmental Impacts

Collateral environmental benefits of IGCC plants include reduced water consumption and the capability to generate less solid waste and generate it in forms—such as inert slag and high-purity sulfur or sulfuric acid—that can be sold as byproducts. However, it should be noted that just as low reliability inherent in the deployment of a new technology is likely to have negative energy impacts, adverse environmental impacts would be expected from the additional emissions associated with startups, shutdowns and malfunctions. The increased emissions associated with these operations would be especially likely to affect the emissions performance of an IGCC facility under the conditions at Dry Fork Station, since the unique size, elevation and fuel source would be expected to reduce reliability for an IGCC plant. IGCC facilities also generate additional emissions as part of their operations. For example SO_2, NO_x, H_2O and CO_2 may be emitted from the sulfur recovery process, tail gas incineration, tanks vents, and flaring of syngas.

ENV Comment #6 (NPS #3, p. 3-4)

WDEQ and Basin Electric failed to evaluate a supercritical boiler in the Dry Fork BACT analysis.

Response: *See response to NPS Comment #3.*

ENV Comment #7.a

WY must set BACT limits with averaging times consistent with the shortest period of the applicable NAAQS and PSD standards, including visibility at Class I areas. Annual average limits do not require meeting BACT on a continuous basis because the source could emit uncontrolled during the year and still meet the annual average.

Response: *BACT is an emissions limitation that is a combination of averaging periods and emission rates. See Newmont EAB Decision at 18 (discussing difference between emissions limitation and emission rate). The averaging times for the applicable NAAQS and PSD increments for NO_x are annual, thus Basin's annual averaging time for NO_x is consistent with the shortest period of the applicable NAAQS and PSD increments. For SO_2, Basin has a 30-day and a 3-hour block average, in addition to the annual average. The modeling for SO_2 used the 3-hour lb/hr limit to demonstrate compliance with the NAAQS and PSD increments (and visibility), as specified in EPA guidance. Permit Application Analysis at 22, 38; EPA NSR Manual at B.56. The modeling for 24-hour SO_2 was based on the proposed 3-hour SO_2 emission limit. Permit Application at 8-9. The modeling for NO_x for visibility was based on 266 lb/hr, which Basin cannot exceed if it meets the 30-day average of 190 lb/hr and the annual average of 0.05 lb/MMBtu, as explained above in response to NPS Comment # 10.*

Even though Basin's permit limits are already consistent with the shortest period of the applicable NAAQS and PSD increments, Basin proposes a NO_x emission rate of 0.07 lb/MMBtu on a 30-day average and 0.05 lb/MMBtu on an annual average, and would accept an SO_2 limit, at a level to be determined, on a 30-day average, in addition to the 0.08 lb/MMBtu on an annual average. See response to EPA Comment #4.

As discussed in NPS Comment #10, the short-term lbs/hr limits for NO_x do not allow for uncontrolled emissions. Similarly, the short-term lbs/hr limits for SO_2 do not allow for uncontrolled emissions. Basin must be in compliance with the 380.1 lb/hr (3-hour average) limit for SO_2, as well as the 30-day and annual averages for SO_2.

In addition to the emission limits for SO_2 and NOx, WDEQ concluded that good combustion controls with an emission limit of 0.15 lb/MMBtu (30-day averaging period) and 570.2 lb/hr (30-day average) for CO is BACT. See response to EPA Comments #7 and 14; Permit Application Analysis at 47. A shorter-term limit for CO is not necessary at Dry Fork because the NAAQS are not in jeopardy. Considering the 30-day averages for CO (accounting for conditions during startup) are a fraction of the NAAQS there is no need for a shorter-term limit for CO.

Further, the permit has a 0.012 lb/MMBtu limit for filterable PM_{10}, as demonstrated by three 1-hour stack tests. These averaging periods and limits ensure compliance with limits that have been demonstrated in the modeling to meet the 24-hour PM_{10} standard and increment.

ENV Comment #7.b.

The outlet NO_x emission rate expected from the Dry Fork boiler of 0.20 to 0.25 lb/MMBtu is too high. Vendor information indicates that current state-of-the-art low NO_x burners and over fire air can achieve boiler outlet NO_x emission rates of 0.17 lb/MMBtu and even lower to 0.13 lb/MMBtu, even with wall-fired boiler.

***Response**: The NO_x emission limit at Dry Fork is based on performance of the SCR system on a proposed boiler. Engineering data show that the percent reductions achieved at high "feed rate" to the SCR may not be achieved with relatively lower feed rates from the proposed boiler, even though overall NO_x emissions will be less at the lower feed rate. The uncontrolled emission factor of 0.20 to 0.25 lb/MMBtu from the boiler was provided as an estimate from a potential bidder, it is not a guarantee, and a vendor was not specifically selected for this facility, given the fact that the design level was not guaranteed. Therefore the use of the 0.20 to 0.25 lb/MMBtu estimate for uncontrolled boiler emissions can be viewed as a vendor estimate only, not a guarantee and not specifically achievable in the proposed power plant. In fact, it may well be that the final uncontrolled emission factor is higher, resulting in a greater back calculated control efficiency for NO_x emissions. The fact that the higher the uncontrolled emissions are, the higher the resulting control efficiency is, illustrates the flaw in relying on control efficiencies rather than controlled emission limits. The more critical information for addressing BACT and air quality and environmental impacts is the resulting emissions rate not a control efficiency that may only reflect higher uncontrolled emissions. EPA's recent pre-publication proposed revisions to the NSPS for Electric Utility Steam Generating Plants, Subpart Da, recognizes this by eliminating its prior focus on control efficiencies in favor of regulating outlet emissions and not control efficiencies. 70 Fed. Reg. 9705 (Feb. 28, 2005).*

Basin is installing the best available control technology at Dry Fork and the issue is what emission limit represents the lowest limit that Basin can consistently achieve to ensure permit compliance. The boiler outlet NO_x emissions are not critical to this determination. Lower NO_x emissions from the boiler do not equal lower NO_x emissions overall. The controlled emission *rate applies at the outlet of the SCR and the higher the inlet NO_x emissions the more efficient the SCR operates, resulting in equivalent NO_x emission rates from the SCR even with varying NO_x input rates.*

Further, reducing furnace NO_x emissions will increase CO emissions because NO_x pollution control equipment, in combination with combustion controls, are designed and operated to achieve the optimum balance between CO and NO_x emissions. While NO_x emissions can be controlled by the SCR, there is no control for CO besides good combustion controls, so it is better to emit higher NO_x and lower CO from the boiler since the higher NO_x will be subsequently controlled. Typical practice is to design the furnace/combustion system (specifically, the air/fuel mixture and furnace temperature) such that CO emissions are reduced as much as possible without causing NO_x levels to significantly increase. The outlet NO_x emissions expected from the Dry Fork boiler are based on control of CO emissions and do not determine the overall emission rate of NOx. The controlled NO_x emission rate is determined by the SCR.

ENV Comment #7.b.(2)

Neither Basin Electric nor WDEQ evaluated the maximum degree of NO_x reduction that can be achieved with SCR at Dry Fork. Even at Basin's higher boiler NO_x emission rates of 0.20-0.25 lb/MMBtu, 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. Even the more stringent WDEQ emission limit of 0.05 lb/MMBtu only reflects 80 percent control from the SCR. According to Babcock & Wilcox, commercial SCR installations have shown that 90 percent NO_x reductions can be achieved with low ammonia slip. Indeed, Babcock & Wilcox states that up to 95 percent NO_x control can be achieved with SCR.

Response: *Basin's proposed Response to NO_x emission rate of 0.07 lb/MMBtu on a 30-day average is BACT for Dry Fork (as discussed in EPA Comment #4). Basin prepared a NO_x BACT analysis for the Dry Fork boiler as part of the original Permit Application submitted in November 2005, and provided additional analysis in its March 2006 Response. A detailed analysis including the status of SCR technology, operating history of existing subbituminous coal units utilizing SCR, and cost effectiveness comparisons were provided in Attachment 2 to the March 2006 Response (Exhibit 3).*

The ranking listed SCR as the most effective control technology. While the analysis discussed some environmental and economic impacts associated with SCR, SCR was nevertheless selected as the BACT control option. In addition, the BACT determination selected SCR along with low NO_x burners using over-fire air as BACT. The analysis then assessed achievable NO_x emission limits using this technology. Two recently permitted facilities burning PRB coal, Mid-American Council Bluffs Unit 4 and Black Hills Corp. Wygen 2, had NO_x limits of 0.07 lb/MMBtu (30-day average). The analysis also discussed the further adverse environmental impacts, in the form of ammonia slip and the additional adverse economic costs caused by catalyst degradation and more frequent catalyst replacement, that could be caused by attempts to achieve an even lower NO_x emission rate. See EPA NSR Manual at B.52 ("SCR technology itself results in emission of ammonia, which increase, generally speaking, with increasing levels of NO_x control.").

It is Basin's contention that the technical evaluations and cost-effectiveness evaluations submitted to date address the "actual average emission level of approximately 0.04 lb/MMBtu" that is of interest to the Division. As described in more detail below, Basin evaluated actual emissions data from three subbituminous-fired units equipped with SCR. Basin calculated the actual average 30-day emission rates achieved in practice, and evaluated the variability in the 30-day average emission rate to establish a corresponding permit limit. Based on emissions data from existing similar sources, coupled with information from control technology vendors, anticipated guarantee limits, emission rates recently permitted as BACT, and engineering judgment, Basin evaluated the cost effectiveness of SCR designed to meet the actual average emission rates ("design targets") and corresponding permit limits listed below:

Table 7

Actual Average Emission Level (Design Target – lb/MMBtu)	Corresponding Permit Limit (lb/MMBtu)
0.04	0.056 (LAER)*
0.043	0.06
0.05	0.07
0.057	0.08
0.064	0.09
*Based on the average 30-day NO_x emission rate achieved using a 95% confidence level at Parish Units 5 and 6, which are both located in the Houston/Galveston severe ozone non-attainment area.	

There are very few units in operation that burn subbituminous PRB coal, utilize SCR for NO_x control and have emission rates of 0.07 lb/MMBtu or lower. The March 2006 Response (Exhibit 3) provided a summary of operating data for Hawthorne Unit 5 and Parish Units 5 and 6 to show actual performance, including hourly emission rates and variability in emissions rates achieved over an extended period of time. Hawthorne Unit 5 has a permit limit of 0.08 lb/MMBtu 30-day average and was able to achieve an average actual emission rate of approximately 0.072 lb/MMBtu in 2004/2005. In contrast, the Parish units do not have a NO_x permit limit, but Basin's prior analysis reported that the Parish units have achieved an average actual emission rate of approximately 0.040 lb/MMBtu 30-day average in an effort to meet their stringent LAER permit limit for the Houston ozone non-attainment area. However, more recent data indicates that Parish's actual emissions are exceeding 0.05 lb/MMBtu on a 30-day average.

As discussed in the prior analysis, the 0.072 lb/MMBtu rate at Hawthorne and the 0.040 lb/MMBtu rate (now exceeding 0.05 lb/MMBtu) at Parish are average actual 30-day operating values; therefore, actual 30-day average emission rates have exceeded these rates approximately 50% of the time. This identifies the need for margin between the actual average emission rate and an enforceable permit limit. There must be sufficient margin to operate continuously under the permit limit to account for normal operating variables that influence the controlled NO_x

emission rate, including changes in the uncontrolled NO_x emission rate, fluctuations in the ammonia- NO_x stoichiometric ratio, flue gas temperatures, and degraded performance of catalysts over time. Based on a statistical analysis of the variability seen in the controlled NO_x emission rates at Hawthorn and Parish, Basin developed "permit limits" corresponding to the actual average emission rates achieved in practice. This was the basis of the conclusion that a NO_x permit limit of approximately 0.056 lb/MMBtu represents the current lowest achievable emission rate (LAER).

As discussed in the March 2006 Response (Exhibit 3), the incremental cost effectiveness of the SCR control system significantly increases below a controlled NO_x emission rate (i.e., permit limit) of 0.07 lb/MMBtu due to increased capital cost (larger SCR and additional catalyst layers) and higher operating costs (increased ammonia usage, increased pressure drop across the SCR, and more frequent catalyst changes). Between 0.08 and 0.07 lb/MMBtu the incremental cost is estimated to be \$2,460/ton, between 0.07 and 0.06 lb/MMBtu the incremental cost increases to \$7,210/ton, and between 0.06 and 0.056 lb/MMBtu the incremental cost is estimated to be \$17,810 per ton of NO_x removed. The cost effectiveness evaluations are budget level estimates based on assumptions as to catalyst volume, catalyst life, ammonia- NO_x stoichiometry, pressure drop, etc., however, it is clear that the SCR control system becomes less cost effective as the technical limit of the control technology is approached.

Finally, evaluating an SCR control system at an enforceable permit limit of 0.05 lb/MMBtu (30-day average) would require the system to achieve an actual average emission rate in the range of 0.030 to 0.035 lb/MMBtu, to account for system variability and to provide reasonable assurance of compliance. A controlled emission rate at this level is below the demonstrated capability of the control technology.

A permit limit below 0.07 lb/MMBtu (30-day average) would eliminate almost all margin between recent design targets for SCR control systems and the permit limit. The BACT emission limit established during the PSD permitting process will be enforceable over the life of the permit. The only "BACT" unit operating on subbituminous coal is Hawthorne Unit 5 with a permit limit of 0.08 lb/MMBtu 30-day average. Basin proposed the use of SCR with a NO_x emission rate of 0.07 lb/MMBtu based on a 30-day rolling average as BACT for the proposed Dry Fork Station project.

An acceptable BACT emission limit must take into consideration the controlled emission rate, emission units (e.g., lb/MMBtu or lb/hr), and associated averaging time. Based on a comprehensive evaluation of SCR performance, Basin agreed to accept the more stringent NO_x BACT limits of 0.05 lb/MMBtu (annual average) and 190.1 lb/hr (30-day average). Basin agreed to the more stringent lb/MMBtu limit (which is very close to the design performance target of the control technology) because of the associated long-term averaging time. An averaging period based on 12-months of operation should provide Basin with adequate time to track SCR performance, identify trends in the controlled NO_x emission rates, plan for potential SCR operating impacts, and schedule SCR maintenance and catalyst management. Because the unit must be brought off-line to replace catalyst and perform maintenance, and because of the potentially significant balance-of-plant impacts associated with excess ammonia injection, Basin could not accept an enforceable emission limit of 0.05 lb/MMBtu based on a short-term averaging time.

However, Basin agreed to accept an enforceable emission limit of 190.1 lb/hr based on a 30-day averaging time. An enforceable emission limit of 190.1 lb/hr still requires the SCR to achieve optimal performance, while providing reasonable compliance options to avoid potential operational problems such as excess slip, air heater pluggage, and odorous fly ash. For example, rather than flooding the SCR with ammonia to maintain a NO_x rate of 0.05 lb/MMBtu, Basin would have the option of keeping ammonia injection at an acceptable rate and reducing boiler load to maintain NO_x emissions below 190.1 lb/hr. On the other hand, the SCR control system will still need to be operated to achieve stringent NO_x emission rates (lb/MMBtu) at all boiler operating loads. For example, even at 80% heat input to the boiler (3,041 MMBtu/hr) the SCR will need to achieve a controlled NO_x emission rate below 0.0625 lb/MMBtu to meet an emission limit of 190.1 lb/hr.

As WDEQ noted in the Permit Application Analysis, Basin agreed to accept NO_x BACT emission limits of 0.05 lb/MMBtu (annual average) and 190.1 lb/hr (30-day average). It is Basin's position that these NO_x BACT limits represent very aggressive permit limits, while providing Basin with reasonable compliance options. These NO_x BACT limits, in combination with Basin's proposed 30-day average of 0.07 lb/MMBtu, represent even more aggressive permit limits than those set forth in the Permit Application Analysis. Permit writers retain discretion to set BACT levels that "do not necessarily reflect the highest possible control efficiencies but, rather, will allow permittees to achieve compliance on a consistent basis." Newmont EAB Decision at 18 (citing In re Steel Dynamics, Inc., 9 E.A.D. at 188; accord In re Three Mountain Power, L.L.C., 10 E.A.D. at 53.). These are the lowest permit limits that will allow Basin to achieve compliance on a consistent basis.

Basin has reviewed the Babcock & Wilcox paper, How Low Can We Go, Controlling Emissions in New Coal Fired Power Plants (G. T. Bielawski, J. B. Rogan & D. K. McDonald). The paper outlined aspirational goals only. Babcock & Wilcox did not present these values as guarantees that any boiler would be able to meet the very low, never before achieved limits. See Newmont EAB Decision at 31–34 (discussing hypothetical limits set forth in the Babcock & Wilcox paper). The paper does not provide a sufficient basis for concluding that these limits are achievable in practice, for an extended period of time. Id. Additionally, the authors of the paper have indicated that the limits suggested in the paper were aspirational and they are not aware of any currently available technology that could achieve these aspirational limits, nor of any facility that has proposed to or is currently achieving these limits. Id. (citing Newmont comments). Thus, this technology has not been demonstrated and cannot be considered commercially available. Further, the paper was published before the issue of SCR catalyst poisoning and blinding caused by PRB ash surfaced, and did not, therefore, take this into account when estimating the low NO_x level suggested.

Just as the EAB concluded in the Newmont EAB Decision that the emission rates in the Babcock & Wilcox paper could be rejected as hypothetical only and not something the TS Power Plant could reasonably achieve in practice on a consistent basis, Basin has concluded that the hypothetical Babcock & Wilcox limits cannot be reasonably achieved in practice on a consistent basis at the Dry Fork plant. Newmont EAB Decision at 33; Permit Application at 5.2.4 (NOx), as amended by March 2006 Response at Attachment No. 2 (NOx) (Exhibit 3) (discussing achievable permit limits at Dry Fork). Again, permit writers retain discretion to set BACT levels that "do not necessarily reflect the highest possible control efficiencies but, rather, will allow *permittees to achieve compliance on a consistent basis." Newmont EAB Decision at 18 (citing In re Steel Dynamics, Inc., 9 E.A.D. at 188; accord In re Three Mountain Power, L.L.C., 10 E.A.D. at 53).*

Rather than focusing on control efficiencies that may only reflect higher uncontrolled emissions, the more critical information for addressing BACT and air quality and environmental impacts is the resulting emissions rate. The NO_x BACT emission limit does not reflect the maximum degree of control that Basin's NO_x controls will achieve at any given point in time; it reflects the lowest emission rate that Basin can consistently meet. See Newmont EAB Decision at 43 (discussing use of emissions rates rather than control efficiencies). Basin fully expects to achieve lower NO_x emission rates during periods of operating its boiler, but understands from extensive discussions with boiler manufacturers and vendors that the limit in the WDEQ permit is the lowest limit that it can consistently achieve. Newmont EAB Decision at 18 (permit writers have discretion to set BACT levels that will allow permittees to consistently achieve compliance); Prairie State EAB Decision at 72–73.

ENV Comment #7.b.(3)

A 12-month rolling average does not require that Basin operate its NO_x pollution control equipment in a manner consistent with achieving the maximum reduction in emissions on a continuous basis.

Response: *Basin's permit requires that it meet a 190.1 lb/hr permit limit on a 30-day rolling average, as well as annual average emission rate of 0.05 lb/MMBtu (annual average). An emission rate of 0.05 lb/MMBtu heat input is equivalent to a rate of approximately 0.46 lb/MWh-gross output. The 0.05 lb/MMBtu emission rate is very close to the design limit of the SCR control system and ensures that Basin must respond quickly to short-term spikes in the controlled NO_x emission rate. In other words, the Dry Fork boiler could not be operated for extended periods of time significantly above 0.05 lb/MMBtu without jeopardizing compliance with the annual average permit limit.*

The annual emission rate of 0.05 lb/MMBtu is even more limiting given the methodology that the station must use to calculate the 12-month rolling average. The equation used to calculate the 12-month rolling average applies the same "weight" to each hourly emission rate (lb/MMBtu) regardless of boiler load. In other words, the equation counts each hourly emission rate (lb/MMBtu) equally without taking into account heat input or boiler load. Thus, Basin could not operate the boiler at low loads and high NO_x emissions for an extended period of time without jeopardizing compliance with the annual average.

For example, assume the boiler were operated at 40% load and 190.1 lb/hr (1,520 MMBtu/hr x 0.125 lb/MMBtu = 190 lb/hr) for 30 consecutive days (30 days x 24 hours = 720 hours). For the remaining eleven 30-day periods in the year (7,920 hours) Basin would have to keep NO_x emissions below 0.043 lb/MMBtu to achieve compliance with the 0.05 lb/MMBtu (annual average) permit limit. An emission rate of 0.043 lb/MMBtu is essentially equivalent to the design limit of the control system. There is no practical operating scenario wherein Basin would operate the SCR at its design limits for eleven months and then operate the boiler at low loads and high NO_x rates for one 30-day period.

Finally, in addition to the 0.05 lb/MMBtu (annual average) and 190.1 lb/hr (30-day average) emission rates, the draft permit requires Basin to meet the NSPS emission limit (Permit Application Analysis at 47). Therefore, even in the highly unlikely event that the boiler is operated at low loads for an extended period of time, Basin would be required to meet, at a minimum, the 1.0 lb/MWh gross NSPS limit.

There are no practical operating scenarios wherein Basin could be in compliance with the 0.05 lb/MMBtu (annual average) limit and the 190.1 lb/hr (30-day average) while not complying with the 1.0 lb/MWh-gross output NSPS limit. The only conceivable operating scenario requires the boiler to be operated at low loads (<45% of maximum) for more than 30 consecutive days. However, even under this scenario, Basin must continue to meet an annual average emission rate of 0.05 lb/MMBtu. Given the methodology mandated to calculate the 12-month rolling average, Basin could not operate the boiler at low loads and high NO_x emission rates for any extended period of time without risking non-compliance with the annual average limit. Under all reasonably anticipated operating scenarios, the permit requirements are significantly more stringent than the corresponding NSPS emission limitation.

As discussed in response to EPA Comment # 4, Basin agrees to an additional NO_x emission rate of 0.07 lb/MMBtu on a 30-day average. This proposed limit, in conjunction with Basin's 30-day rolling average lbs/hr NO_x emission limit, requires Basin to operate the boiler burners and SCR at maximum efficiency when operating the plant at maximum load. As discussed in the responses to NPS Comment #10 and ENV Comment #7, the short-term lbs/hr limit for NO_x does not allow for uncontrolled emissions. Under the short-term lbs/hr limits, the only time Basin could be operating uncontrolled would be at low boiler loads, which is not a practical operating scenario for Dry Fork since Basin has an economic incentive to operate at high (full) boiler loads. This will require the maximum control of NO_x at Dry Fork.

Finally, the comment appears to misconstrue what is required under BACT. Because a BACT limit is a function of both numerical limits and averaging times, the only compliance requirement is that the numerical limit be met over the specified averaging time. Thus, a NO_x limit of 0.05 lb/MMBtu, annual average, does not imply that an emission rate of 0.05 lb/MMBtu must be met during a 24-hour or 30-day averaging time.

ENV Comment #7.b.(4)

The 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 ensures that the pollution control equipment will be operated to provide the maximum emission reduction achievable on a continuous basis.

Response: *See response to ENV Comment #7.b.(3), above.*

ENV Comment #7.c.

BACT for SO_2 must be at least as stringent as limits required at Newmont Nevada TS power plant.

Response: *While the 0.065 lb/MMBtu limit permitted for the TS Power Plant is lower than that proposed for the Dry Fork Station power plant, this facility has not been constructed and the SO_2 BACT limit has not been demonstrated in practice. A permit issuer may appropriately consider, as part of its BACT analysis, the extent to which available data in the record evidence the ability to consistently achieve certain emissions rates or control effectiveness of the selected technology or pollution control method. Newmont EAB Decision at 15. While previous permit decisions can provide guidance for future BACT determinations, permitting agencies must establish BACT on a case-by-case basis and facility-by-facility basis. EPA's NSR Manual states the following regarding the basis for BACT limits:*

> *Manufacturer's data, engineering estimates and the experience of other sources provide the basis for determining achievable limits. Consequently, in assessing the capability of the control alternative, latitude exists to consider any special circumstances pertinent to the specific source under review, or regarding the prior application of the control alternative.*

EPA NSR Manual at B.24.

While Basin's proposed SO_2 limit of 0.08 lb/MMBtu would not be the lowest BACT limit ever permitted, 0.08 lb/MMBtu represents the maximum degree of reduction for SO_2 at the Basin PC-fired boiler, taking into account energy, environmental, and economic impacts. The proposed SO_2 BACT limit takes into account Basin's facility-specific boiler size, boiler design, fuel options, and emission controls, and is the lowest BACT limit that Basin has determined is achievable on a consistent basis at its facility. Since the Basin Facility is unique in its design, it would be unreasonable to require Basin to meet a SO_2 BACT limit of 0.065 lb/MMBtu simply because this limit has been permitted for another facility. The EAB recently stated agreement with this position:

> *PSD permit limits are not necessarily a direct translation of the lowest emissions rate that has been achieved by a particular technology at another facility, but that those limits must also reflect consideration of any practical difficulties associated with using the control technology.*

Newmont EAB Decision at 17.

Basin's proposed SO_2 BACT limit of 0.08 lb/MMBtu is based on careful engineering evaluation, vendor consultation, and consideration of the energy, environmental and economic impacts as documented above for this unique facility. For all of the reasons discussed above, the 0.08 lb/MMBtu permit limit is BACT for SO_2 at the Dry Fork plant.

<u>Comparison with TS Power Plant</u>

More specifically, additional review and comparison of the proposed Basin Dry Fork Station SO_2 BACT emission limits to other recently issued/proposed SO_2 BACT limits (particularly the SO_2 emission limits for the TS Power Plant included in the Newmont permit to construct issued by the Nevada Bureau of Air Pollution Control), is provided below to support

Basin's BACT requirement for SO_2. The review below draws on Sargent & Lundy, Memorandum regarding Proposed SO_2 Emission Limits, Dry Fork v. Newmont TS Power, June 8, 2007, Exhibit 25.

Basin's BACT determination, including the original permit application and supplemental information submitted in response to agency comments, included a detailed evaluation of potentially feasible SO_2 control technologies. The BACT analysis included an evaluation of both wet and dry flue gas desulfurization (FGD) systems, and an evaluation of the controlled emission rates achieved in practice at the best controlled similar sources. Based on information included in Basin's BACT analysis, WDEQ proposed the following SO_2 BACT emission limits:

- *0.08 lb/MMBtu (12-month rolling average)*
- *304.1 lb/hr (30-day rolling average)*
- *380.1 lb/hr (3-hour block average)*

In addition, the facility will be required to meet the applicable NSPS (1.4 lb/MW-hr 30-day rolling average) and an annual SO_2 emission limit of 1,331.8 tpy.

Basin's BACT analysis included a comparison of Dry Fork's proposed SO_2 limits to other recently issued/proposed BACT limits for coal-fired boilers (see, permit application Appendix E, and information included in Basin's December 13, 2006 response to questions). Of the recently permitted pulverized coal-fired units proposing to fire subbituminous coal and control SO_2 emissions using dry FGD, the most stringent SO_2 emission rates identified as BACT were imposed on the Newmont Power Plant proposed in Eureka County, Nevada. The TS Power Plant is subject to the following SO_2 BACT emission limits:

<u>Newmont Nevada TS Power:</u>

While combusting coal with a sulfur content > 0.45% (30-day rolling period) based on daily ASTM sampling;

- *0.09 lb/MMBtu (24-hour rolling average);*
- *95% minimum SO_2 removal efficiency (30-day rolling period).*

While combusting coal with a sulfur content <0.45% (30-day rolling period), based on daily ASTM sampling:

- *0.065 lb/MMBtu (24-hour rolling average);*
- *91% minimum SO_2 removal efficiency (30-day rolling period).*

<u>Newmont – Dry Fork Boilers, Fuels and Control Technologies</u>

The Newmont facility is a proposed 200 MW nominal output pulverized coal-fired boiler. The facility is proposing to fire subbituminous coal from the Powder River Basin (PRB) as its primary fuel. Maximum heat input to the boiler will be 2,030 MMBtu/hr (Information regarding the proposed Newmont boiler was obtained from: Newmont Nevada Energy Investment, LLC, Class I Air Quality Operating Permit to Construct, No. AP-4911-1349). The Dry Fork unit will be 422 MW-gross (385 MW-net) pulverized coal-fired boiler. The Dry Fork unit will fire *subbituminous coal from the adjacent Dry Fork mine as its primary fuel. The unit will have a heat input at maximum load of approximately 3,801 MMBtu/hr.*

The most significant differences between Newmont and Dry Fork are the size of the boilers and proposed fuel characteristics. The Dry Fork boiler will be approximately twice the size of the Newmont boiler, with a heat input at maximum load of 3,801 MMBtu/hr compared to 2,030 MMBtu/hr for Newmont. The higher heat input results in correspondingly higher flue gas flow rates. A second distinction between the two projects is that Dry Fork will be a mine-mouth plant. Coal from the Dry Fork Mine will be delivered to the power plant via an overland conveyor. Samples from the Dry Fork Mine show considerable variability in the coal characteristics throughout the mine, including variability in the heating value, moisture content, ash, and sulfur content. Based on available analyses, the Dry Fork Station is being designed to fire coal with a heating value between approximately 7,800 and 8,300 MMBtu/lb and a sulfur content in the range of 0.47%. Permit Application at Table 2-1.

The Newmont facility proposed firing subbituminous PRB coal as its primary fuel. Coal will be delivered to the facility by rail from various mines throughout the Powder River Basin. Based on a review of fuel characteristics data available from the National Coal Resources (NCR) Data System, PRB coals from Wyoming mines have heating values in the range of approximately 8,200 to 8,800 Btu/lb and sulfur contents in the range of approximately 0.30 to 0.80%. Median heating values and sulfur contents for Wyoming PRB coals in the NCR Data System were 8,550 and 0.61, respectively.

Evaluation of Newmont's Permit Limits

When firing coal with a sulfur content <0.45% the Newmont facility will be required to achieve a controlled SO_2 emission rate of 0.065 lb/MMBtu (24-hour average) and a minimum removal efficiency of 91% (30-day rolling period). When firing coal with greater than 0.45% sulfur, the Newmont facility will need to achieve a controlled emission rate of 0.09 lb/MMBtu (24-hour average) and 95% removal. For reasons provided below, it is Basin's position that these permit limits are either equivalent to the design limits of the proposed control technology or beyond the capability of the emission control technology, and are not achievable on an on-going long-term basis.

Dry FGD – Spray Dryer Absorber

The Newmont facility proposed dry FGD designed as a spray dryer absorber (SDA) as BACT for SO_2 control. SDA control systems use a slurry of lime and water injected into the reaction tower to remove SO_2 from the combustion gases. The reaction tower must be designed to provide adequate contact and residence time between the slurry and the exhaust gas, while producing a dry by-product that will be captured in the unit's downstream fabric filter baghouse.

Control efficiencies achievable with an SDA control system are limited by physical and chemical design constraints of the system. Process parameters affecting efficiency of the SDA include the alkalinity-to-SO_2 stoichiometric ratio, temperature drop across the reaction vessel, and how close the SDA is operated to saturation conditions. Alkalinity of the feed slurry can be controlled by adjusting the ratio of fresh lime slurry to recycle slurry. Increasing the ratio of *fresh lime will increase the alkalinity-to- SO_2 stoichiometric ratio and incrementally increase SO_2 removal. However, injecting excess slurry, such that the reactant by-product does not completely dry prior to exiting the reaction vessel, will create significant operating problems with the control system.*

Increasing the inlet gas temperature to the SDA may provide additional temperature drop across the reaction vessel to allow a small increase in slurry feed. However, increasing the inlet temperature to the vessel will reduce overall boiler efficiency and increase other emissions on a pound-per-net megawatt basis. Operating the system at an outlet temperature approaching saturation may incrementally increase SO_2 removal. However, operating the SDA too close to saturation will create significant operational problems including wall wetting, scaling, and plugging, as well as significant operational problems with the downstream baghouse. Because the slurry feed rate is limited and the SDA must be operated above the saturation temperature in order to produce a dry reactant by-product, control efficiencies with SDA control systems are limited to a range of 94% to 95%.

Based on information obtained from similar recent projects (i.e., subbituminous coal-fired boilers equipped with an SDA control system) and detailed discussions and negotiations with SDA equipment vendors, the most aggressive, sustainable, and commercially acceptable guarantees currently available from SDA vendors are in the range of 94% control <u>or</u> a floor of 0.08 lb/MMBtu, whichever is achieved first. Compliance with guaranteed emission rates are typically demonstrated based on a one-time test defined in the equipment specification and conducted under new and clean conditions. In other words, for coals generating uncontrolled SO_2 emissions above approximately 1.33 lb/MMBtu, vendors will guarantee 94% removal. However, for coals generating uncontrolled SO_2 emissions below 1.33 lb/MMBtu, rather than guaranteeing 94% removal vendors will guarantee a controlled emission rate of 0.08 lb/MMBtu. An emission rate of 0.08 lb/MMBtu is equivalent to an SO_2 concentration in the flue gas of approximately 40 ppmvd @ 3% O_2, a concentration below which vendors have not been willing to guarantee additional SO_2 capture.

When reviewing potential vendor guarantees it is important to keep in mind that compliance with a guaranteed emission rate is typically demonstrated based on a one-time test defined in the equipment specification and conducted under strict supervision when the unit and emission control systems are in new and clear condition. Emission control technology vendors are not required to demonstrate compliance with the guaranteed emission rates on an on-going long-term basis and under all normal boiler operating conditions. However, it may be possible to obtain more aggressive guarantees with less acceptable commercial terms. Similarly, more aggressive guarantees may be available if the vendor's liabilities associated with missing the guarantees are limited.

For this evaluation it will be assumed that an SDA control system could be designed to achieve a removal efficiency of 95% or a controlled emission rate of 0.06 lb/MMBtu, whichever is achieved first. This control efficiency and emission rate represent short-term system performance that may be attainable under optimal operating conditions, but do not necessarily represent enforceable BACT emission limits which should include some reasonable compliance margin to account for normal fluctuations in the controlled SO_2 emission rate. Based on the technical/physical limitations of the SDA control system, and recent experience with SDA control *projects, this control efficiency and controlled emission rate represent the technical limits of the SDA control system. However, it should be noted that, to date, vendors have not been willing to guarantee these performance rates over a sustained period of time with acceptable commercial terms.*

Margin Between Performance Target and Permit Limit

The EAB has repeatedly recognized that "permitting agencies have the discretion to set BACT limits at levels that do not necessarily reflect the highest possible control efficiencies but, rather will allow permittees to achieve compliance on a consistent basis." In Re Three Mountain Power, 10 E.A.D. at 59 (citing In re Masonite Corp., 5 E.A.D. 551, 560-61 (EAB 1994) ("There is nothing inherently wrong with setting an emission limitation that takes into account a reasonable safety factor")); and In re Knauf Fiber Glass, GmbH, EAB PSD Appeal Nos. 99-8 to –72, slip op. at 21 (March 14, 2000) ("The inclusion of a reasonable safety factor in the emission limitation is a legitimate method of deriving a specific emission limitation that may not be exceeded."). To establish a reasonable compliance margin for a SDA control system, Basin reviewed controlled SO_2 emission rates currently achieved in practice at the best-controlled similar source (i.e., an electric utility steam generating boiler firing subbituminous coal and equipped with SDA). Actual emissions data from KCPL Hawthorn Unit 5 were evaluated to identify removal efficiencies achieved in practice and variability in the controlled SO_2 emission rate. Hawthorn Unit 5 is the most recently constructed utility boiler firing subbituminous coal and equipped with an SDA control system. The unit currently achieves the lowest annual average controlled SO_2 emission rate for all units equipped with dry FGD (A similar evaluation of the hourly emissions data from KCPL Hawthorn Unit 5 for the time period January 1, 2004 through March was provided to WDEQ in the March 2006 Response (Exhibit 3). That analysis concluded that a margin of 21%, or approximately 0.02 lb/MMBtu, was needed between the performance target guarantee and the enforceable 30-day average permit limit to provide a reasonable opportunity for compliance on a consistent basis.).

Figure 5 (below) shows the actual hourly emissions data reported by Hawthorn Unit 5 for 2005 (Emission data was obtained from EPA's Clean Air Market website: http://cfpub.epa.gov/gdm/). Emission control systems do not operate under steady-state conditions, and controlled emission rates are subject to short-term fluctuations and spikes. Hourly controlled SO_2 emission rates tend to fluctuate around the control system design point. Short-term spikes in controlled emissions might be caused by changes in boiler load, fuel characteristics, flue gas characteristics, and/or routine maintenance procedures. Short-term spikes in the controlled emission rate can be dampened by averaging emissions over a period of time. Figure 6 shows the same data, with the 24-hour and 30-day rolling averages. A summary of the removal efficiencies and the variation in the controlled emission rates achieved during 2005 based on several averaging times is provided in Tables 8 and 9.

Table 8
Average SO_2 Removal Efficiencies
Hawthorn Unit 5 (2005)
Subbituminous Coal / PC Boiler / SDA

		Annual Average	Maximum
Potential Uncontrolled SO_2 Emissions*	lb/MMBtu	0.78	1.09
Annual Controlled Emission Rate	lb/MMBtu	0.103	0.103
Removal Efficiency	%	86.8%	90.6%
*Potential uncontrolled SO2 emission rates were estimated based on a fuel shipment data available from FERC Form 423.			

Table 9
Average SO_2 Controlled Emission Rates
Hawthorn Unit 5 (2005)
Subbituminous Coal / PC Boiler / SDA

		Averaging Time	
		24-hour	30-day
Average Controlled Emission Rate (annual average)	lb/MMBtu	0.103	0.103
Standard Deviation (based on averaging time)	lb/MMBtu	0.071	0.014
Emission Rate at 95% Confidence Level	lb/MMBtu	0.245	0.131
Percent Increase Above Average Emission Rate	%	138%	27%

Based on emissions data submitted to EPA in 2005, the Hawthorn facility achieved an annual average SO_2 removal efficiency of 86.8% and a controlled SO_2 emission rate of 0.103 lb/MMBtu. During this time period the SDA control system showed significant variability, especially on a short-term basis. Based on standard deviation calculations, the controlled SO_2 emission rate achieved during the year on a 24-hour basis at a 95% confidence level was 0.245 lb/MMBtu, more than twice the annual average emission rate.

Some of the short-term variability associated with the SDA control system may be related to the need to routinely replace the atomizing nozzles in the reactant vessel. Reactant spray nozzle designs are vendor-specific, and both dual-fluid nozzles and rotary atomizers have been used in large coal-fired boiler applications. The atomizing nozzle assembly (either the duel-fluid feed lance assembly or the rotary atomizer assembly) is typically located in the SDA penthouse, and flange mounted to the roof of the absorber vessel. Overhead cranes or hoists located in the penthouse can be used to remove the nozzle assemblies from the absorber vessel for repair and ~~maintenance. Because of the abrasive nature of the reactant slurry, nozzle assemblies must be~~ removed and replaced on a routine basis. Depending on the design of the SDA system, one or *more spare nozzle assemblies will be available for use. The nozzle assemblies may be changed without shutting down the SDA system, however, during that time period the SDA may not be able to maintain maximum control efficiencies.*

Newmont Permit Limits

Table 10 shows the permit limits and control efficiencies that Newmont will need to achieve to meet its permit limits based on various fuel characteristics. The heating values and sulfur contents used in Table 6 are in the range for typical PRB subbituminous coals. Controlled emissions shown in brackets represent rates or control efficiencies that are beyond the technical capability of the proposed control technology. Control efficiencies or emission rates that are underlined represent values that are within the technical limits of the control technology, but do not include adequate margin for on-going compliance.

Table 10
Newmont – Control Efficiencies Needed to Meet Permit Limits

Fuel characteristics			Permit Limits		Control Efficiency Needed to Meet Emission Rate	Controlled SO_2 Emission Rate based on Removal Efficiency Requirement
Heating Value (Btu/lb)	Sulfur Content	Potential SO_2	Emission Rate	Control Efficiency		
8,800	0.25	0.57	0.065	91%	88.6%	[0.051]
8,000	0.25	0.625	0.065	91%	89.6%	[0.056]
8,800	0.30	0.68	0.065	91%	90.4%	0.061
8,000	0.30	0.75	0.065	91%	91.3%	0.068 (>0.065)
8,800	0.40	0.91	0.065	91%	92.5%	0.082 (>0.065)
8,000	0.40	1.00	0.065	91%	93.5%	0.090 (>0.065)
8,800	0.45	1.023	0.09	95%	91.2%	[0.051]
8,000	0.45	1.125	0.09	95%	92.0%	[0.056]
8,800	0.50	1.136	0.09	95%	92.1%	[0.057]
8,800	0.60	1.364	0.09	95%	93.4%	0.068
8,800	0.70	1.591	0.09	95%	94.3%	0.080
8,800	0.80	1.818	0.09	95%	95.0%	[0.091 (>0.09)]
8,800	0.90	2.045	0.09	95%	[95.6%]	[0.102 (>0.09)]
8,800	1.0	2.272	0.09	95%	[96.0%]	[0.114 (>0.09)]

[ ] = beyond technical capabilities of the proposed control technology
__ = emission may be technically feasible but does not include adequate compliance margin.

Based on an evaluation of control efficiencies achieved in practice and variability in the controlled SO_2 emission rate associated with an SDA control system, it appears that the Newmont facility may experience significant compliance challenges. For example, when firing coals with less than 0.45% sulfur, the Newmont facility will be required to achieve a controlled SO_2 emission rate of 0.065 lb/MMBtu. As discussed above, it is Basin's position that regardless of the inlet SO_2 emission rate, a controlled emission rate of 0.065 lb/MMBtu is essentially equal to the design limits of the control technology, and does not include adequate compliance margin, *especially on a 24-hour averaging basis. Moreover, when firing very low sulfur coals (e.g., coals with sulfur contents below approximately 0.25%) the Newmont facility needs to maintain a minimum removal efficiency of 91%. Removal efficiencies of 91% or more on very low sulfur coals results in controlled emission rates below 0.06 lb/MMBtu, which are beyond the technical capabilities of the control technology.*

When firing coals with greater than 0.45% sulfur, the Newmont facility will be required to achieve a controlled SO_2 emission rate of 0.09 lb/MMBtu (24-hour average) and a removal efficiency of at least 95% (30-day average). These emission limitations may be achievable over a limited range of fuel characteristics, but provide no margin for normal operating fluctuations. First, a removal efficiency of 95% is essentially equal to the technical limit of the control technology and provides no compliance margin. Second, when firing coals with potential SO_2 emissions greater than approximately 1.9 lb/MMBtu, removal efficiencies greater than 95% will be needed to meet the 0.09 lb/MMBtu emission limit. This control efficiency is above the technical limits of the control technology. Finally, an emission limit of 0.09 lb/MMBtu may not provide adequate compliance margin on a 24-hour basis to account for routine control system maintenance and atomizer change-outs.

<u>Conclusions</u>

Based on a review of anticipated vendor guarantees, emission rates achieved in practice, and an evaluation of the variability associated with dry FGD control systems, it is Basin's conclusion that the SO_2 emission limits included in the Newmont permit are equivalent to, or exceed, the technical limitations of the proposed control equipment. Removal efficiencies and emission rates required in the Newmont permit have not been demonstrated in practice at any existing source.

The proposed permit limits (0.08 lb/MMBtu annual average and 304.1 lb/hr 30-day average) represent controlled emission rates slightly above the design limits for dry FGD control systems. In order to comply with the permit limits, Basin will have to achieve controlled SO_2 emission rates below 0.08 lb/MMBtu (approximately 40 ppmvd @ 3% O_2) under all normal operating conditions. Compliance with the 0.08 lb/MMBtu emission limit will require Basin to achieve annual average removal efficiencies in the range of 93.4% (based on an annual average uncontrolled SO_2 emission rate of 1.21 lb/MMBtu). However, control efficiencies in the range of 94%, and controlled emission rates below 0.08 lb/MMBtu, should be achievable with dry FGD control systems while providing some margin for compliance.

As discussed in response to NPS Comment #4, above, because of the limited margin between the expected design performance target of the SO_2 control system and the proposed permit limits, Basin has decided to configure the dry FGD control system as a circulating dry scrubber (CDS) rather than a SDA. A CDS system uses a circulating fluidized bed of dry hydrated lime reagent to remove SO_2. Flue gas passes through a venturi at the base of a vertical reactor tower and is humidified by a water mist. The humidified flue gas then enters a fluidized bed of powdered hydrated lime and circulated reaction by-products where SO_2 is removed. The desulfurized flue gas passes out of the scrubber, along with reaction products, including unreacted hydrated lime, calcium carbonate, and the fly ash to the particulate removal system (fabric filter baghouse).

Based on information available from equipment vendors and engineering judgment, the CDS DFGD system should be capable of achieving SO_2 removal efficiencies equivalent to those achieved with an SDA. Further, based on a direct project-specific comparison of both DFGD technologies, BEPC concluded the CDS design offered the following advantages over the SDA: (1) the CDS offers a better chance of complying with stringent SO_2 emission rates given the unique challenges at a mine-mouth plant with respect to variability in the fuel characteristics; (2) potential balance-of-plant impacts associated with operating either system so close to the performance target are potentially less significant with the CDS (i.e., the CDS should not experience wall wetting, scaling, plugging and the associated detrimental impacts on the baghouse); and (3) the CDS will not experience short-term emission spikes associated with routine atomizer changeouts and should be better suited to achieve stringent emission rates based on short-term averaging times. Therefore, BEPC is proposing dry FGD, designed as a CDS, as BACT for SO_2 control for Dry Fork Station.

Figure 5
Hawthorne Unit 5 – Hourly SO_2 Emissions Data (2005)

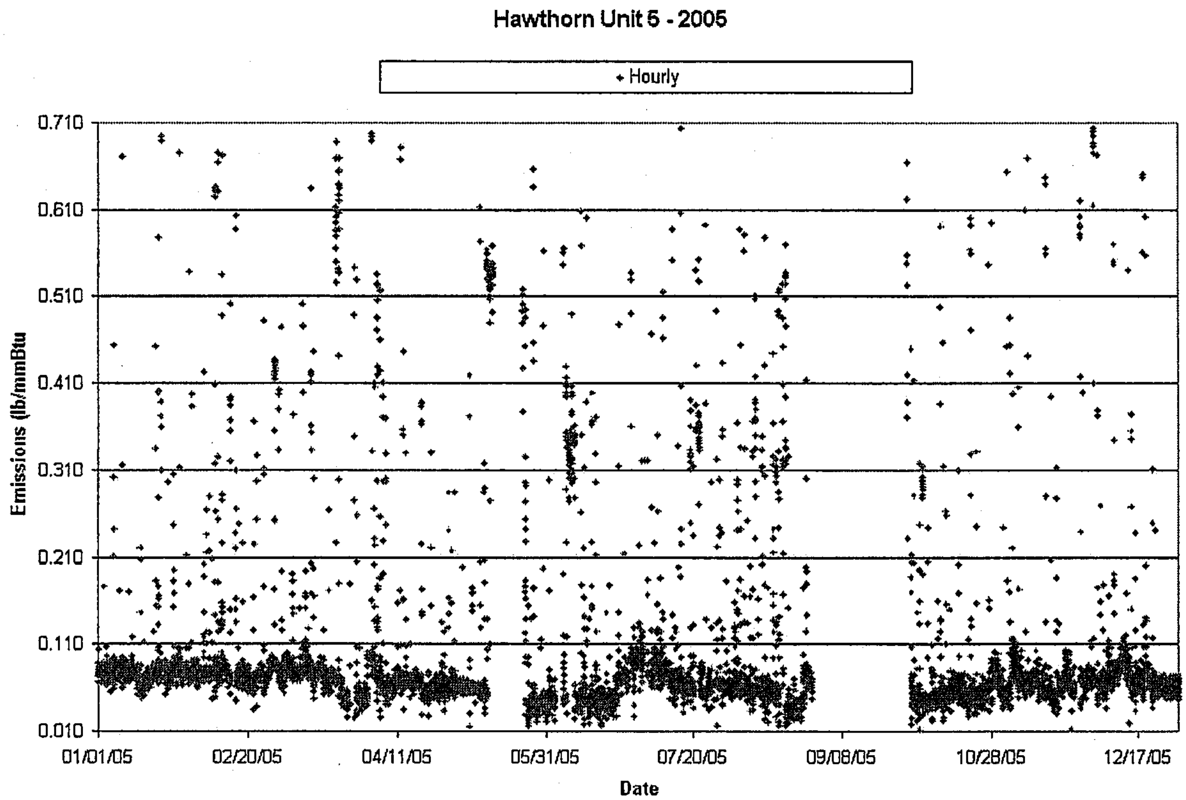
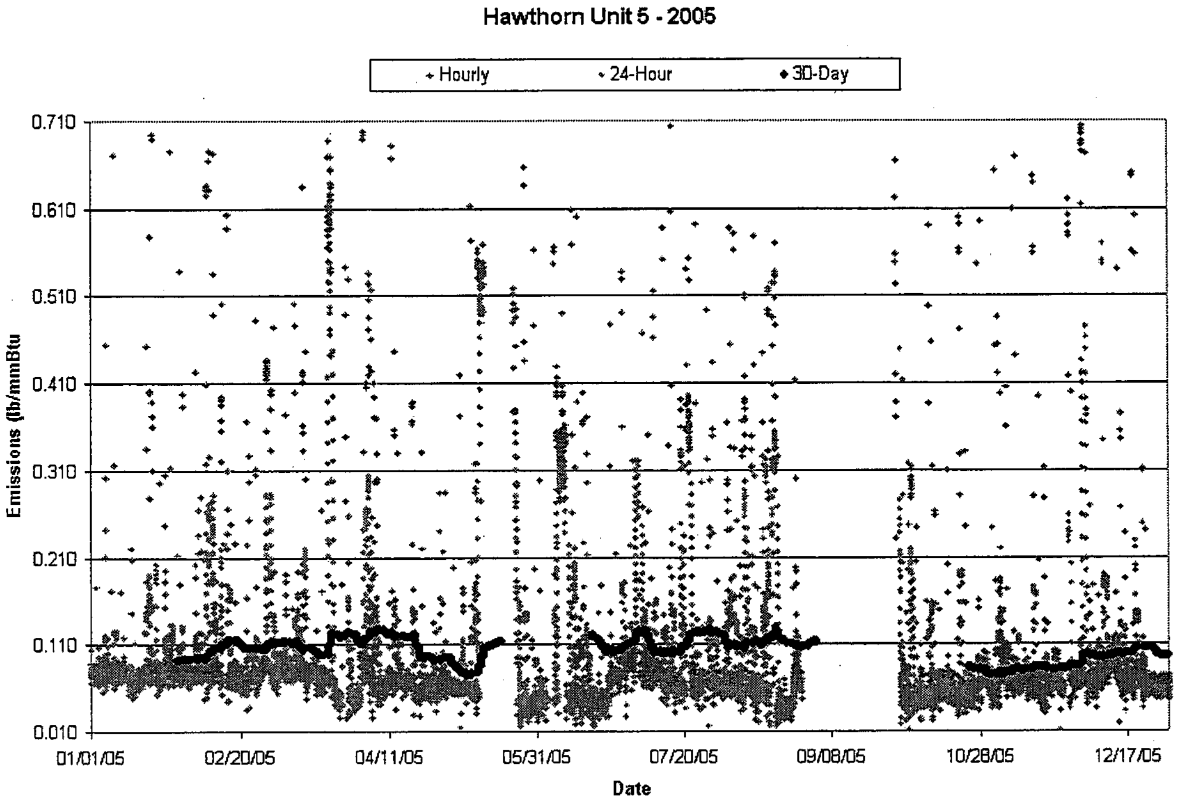


Figure 6
Hawthorne Unit 5 – Hourly SO_2 Emissions Data (2005)



ENV Comment #7.c.(2)

Spray dryer/absorber can achieve greater reduction than proposed limit (at least 90% removal).

***Response**: The actual control efficiency at Dry Fork Station will be 93.4% SO_2 control, based on a 0.08 lb/MMBtu annual average. See response to NPS Comment #5. However, the more critical information for addressing BACT and air quality and environmental impacts is the resulting emissions rate not a control efficiency that may only reflect higher uncontrolled emissions. The amount of SO_2 emitted to the air is what matters, not the removal efficiency. The SO_2 BACT emission limit does not reflect the maximum degree of control that Basin's SO_2 controls will achieve at any given point in time; it reflects the lowest emission rate that Basin can consistently meet. See Newmont EAB Decision at 43 (discussing use of emissions rates rather than control efficiencies). Basin fully expects to achieve lower SO_2 emission rates during periods of operating its boiler, but understands from extensive discussions with boiler manufacturers and vendors that the limit in the WDEQ permit is the lowest limit that it can consistently achieve. Newmont EAB Decision at 18 (permit writers have discretion to set BACT levels that will allow permittees to consistently achieve compliance); Prairie State EAB Decision at 72-73.*

The most aggressive design target would be 94% control based on worst-case design fuel. Although a control rate this low may be an acceptable design target, this control rate does not represent a permit limit or a control rate that can be achieved on a long-term basis under all normal operating conditions. Some reasonable margin must be provided between the design target and the permit limit to allow for normal fluctuations in the controlled emission rate. Allowing a margin of safety for a permit limit is consistent with past EAB decisions. In re Three Mountain Power, 10 E.A.D. at 59 ("permitting agencies have the discretion to set BACT limits at levels that do not necessarily reflect the highest possible control efficiencies but, rather will allow permittees to achieve compliance on a consistent basis.") (citing In re Masonite Corp., 5 E.A.D. at 560-61 ("There is nothing inherently wrong with setting an emission limitation that takes account a reasonable safety factor.")); In re Knauf Fiber Glass, slip op. at 21 ("The inclusion of a reasonable safety factor in the emission limitation is a legitimate method of deriving a specific emission limitation that may not be exceeded."); see also Prairie State EAB Decision at 72-73; Newmont EAB Decision at 17-19.

ENV Comment #7.c.(3)

Given the variability in sulfur content in coal, WDEQ must impose a SO_2 removal efficiency requirement in addition to the emission limit.

Response: *The possible imposition of a percent control requirement on the Dry Fork Station power plant represents a step beyond the permitted control requirements for virtually all recently permitted units. There is no justification that the percent control requirements would achieve a better-functioning or better performing SO_2 scrubber. To suddenly decide to change the form of the entire SO_2 standard is arbitrary and capricious. Accordingly, the permit for Dry Fork Station should not include a percentage removal requirement.*

In fact, BACT is defined as an "emission limitation" that is "based on" the maximum degree of reduction in emissions. 40 C.F.R. § 52.21(b)(12). An operational requirement, such as a minimum control efficiency, may be prescribed instead, if the reviewing authority determines that the imposition of a numerical emission limitation is infeasible: "If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emission unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead, to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results." Id.

This is not the case here; a numerical emission limitation for SO_2 is feasible. EPA's recently released pre-publication proposed revisions to NSPS Subpart Da, announces that EPA is "proposing to replace the current percent reduction requirement for SO_2 in Subpart Da, with an output – based SO_2 emission limit." 70 Fed. Reg. 9705. Thus, EPA itself is acknowledging that the key is not percent of control, but the ultimate emissions to the atmosphere, as limited in the current Permit Application Analysis.

The goal of the application is to accommodate the variability that can be seen in the coal supply. The vendors provided data for the design coal, but Basin is responsible for obtaining a permit limit that can be met, given the variability inherent in PRB coal. It is possible that some coal suppliers will have coal variability, especially over a 24-hour period, which will be above the design coal sulfur content. Relying on varying calculated rates of efficiency depending on the sulfur content of the fuel illustrates the futility in relying on control efficiencies rather than emission rates; the higher the sulfur content of the fuel, the higher the control efficiency, while emissions to the atmosphere will be the same given the proposed permit limit. The permit emission limit, therefore, should be the focus of the BACT review and analysis since it reflects the air quality impact.

There have been a number of PSD permits issued by EPA to coal-fired power plants in the past five years without this provision. A review of recently issued permits, and a review of the RBLC data base indicate that the imposition of a percent reduction requirement for SO_2 controls is very rare. None of the RBLC data base information lists a percent control for SO_2. The eight permits provided in response to this comment (see below) do not include percent reduction requirements. The percent reduction requirement has been included in one power plant permit for PC units. The Roundup Power Project, Bull Mountain, MT, permit issued July 21, 2003, for two 780 MW PC's, SO_2 limit is 0.15 lb/MMBtu for 1-hr, and 0.12 lb/MMBtu for 24-hr. SO_2 removal must be maintained at a minimum of 90% for a 30-day rolling average. This emission limit is substantially above the Dry Fork plant limit and the percent control effectiveness required is less than the values used to calculate the Dry Fork plant proposed emission limit over a longer time period.

Other recent permits for PC boilers issued without percent control requirements include the Manitowoc, WI power plan (Issued May 2001), Kentucky Mountain Power Plant, Central City, KY (issued October 2002), the Longview Power Plant in West Virginia (Consent Order July 2004), the NEVCO-Sevier CFB power plant in Utah (February 2004), the Thoroughbred Generating Station in Muhlenberg County KY (Issued October 2001), the Kentucky Mountain Power Plant in Knott County, KY (August 2000), the Intermountain Power Plant in Delta UT (Issued August 2004), and the Springfield City Utilities Power Plant in Missouri (Issued December 2004).

Some CFB units have percent control requirements in their permits. The Indeck, Ellwood IL, Permit issued March 21, 2002, for two 330 MW CFB's, burning coal/pet coke, SO_2 limit is 0.15 lb/MMBtu; however "if emissions are 0.10 lb/million Btu or greater, 8 percent of the potential combustion concentration (92 percent reduction) of the solid fuel supply, as received" must be controlled. The SO_2 limits are a 30-day rolling average. This permit indicates that the permit for a CFB unit has higher SO_2 emissions and a 30-day rolling average percent emission reduction that is less than that applied in calculating emission limits proposed for the Dry Fork Station power plant. These CFB units fire high sulfur waste coal, have higher SO_2 emission limits (lb/MMBtu) and have percent reductions that are partially based on CFB technology. All emission limits are considerably higher than the Dry Fork Station power plant; and the percent reductions are consistent with the contention that higher control efficiency can be achieved only on burning higher sulfur fuels.

Permitting agencies have discretion in determining whether a particular control efficiency level is appropriate in determining BACT and in setting an appropriate emissions limit. Newmont EAB Decision at 42. For all of the reasons described above, a SO_2 removal efficiency requirement is not necessary for the Dry Fork facility permit.

ENV Comment #7.c.(4)

WDEQ did not analyze sorbent injection systems in the BACT analysis for mercury. WDEQ should require emission limits that reflect greater than 90 percent control (resulting in an emission limit in the range of 6.26 to 10.02E-06 lb/net MW).

Response: *See response to NPS Comment #8 regarding the BACT analysis for mercury. See response to ENV Comment #7.c.(5) regarding percent control requirements for mercury. A true BACT analysis is not possible for mercury because 1) control technologies for mercury are still in the developmental stage, resulting in only limited information regarding possible alternatives and potential control efficiencies; 2) a top-down analysis with cost estimates is not possible with current incomplete technology alternatives and cost information; 3) commercially available mercury control systems and associated vendor guarantees are very limited to date. Activated carbon sorbent injection systems have been proposed and designed by a few vendors but other control technologies are at the planning and demonstration stages. Further, there remains a significant level of uncertainty regarding establishing an appropriate permit limit for mercury emissions: 1) unknown effects from numerous unit operating parameters on mercury capture; 2) uncertainty regarding future coal Mercury levels; 3) current status of CEMs.*

As discussed in response to NPS Comment #8, Basin will install mercury control and will operate it to achieve a target goal of 20 x 10-6 MW/hr on a 12-month rolling average basis.

Basin proposed a Mercury Optimization Study, which would be performed on the Dry Fork Station. This testing program would begin approximately July 2011 (approximately six months after unit start-up), and would continue for one year. Please see response to NPS Comment #8.

The testing program will include a review of the following potential mercury technology options:

a) Sorbent Injection Technologies
b) Sorbent Enhancement Additives
c) Coal Pretreatment Processes
d) Mercury Oxidation Technologies

Results from the testing program would be provided to the WDEQ, and implemented on Dry Fork Station as appropriate. Thus, Basin will analyze sorbent injection systems as part of its testing program. Basin and WDEQ will jointly determine whether permit modifications are necessary. Thus, a lower mercury limit will be applied to the Dry Fork plant as needed following the results of the testing program.

ENV Comment #7.c.(5)

WDEQ 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.

Response: *See response to NPS Comment #8 regarding BACT for mercury. See response to ENV Comment #7.c.(4) regarding percent control requirements. The possible imposition of a percent control requirement for mercury on the Dry Fork Station power plant represents a step beyond the permitted control requirements for virtually all recently permitted units. Accordingly, the permit for Dry Fork Station should not include a percentage removal requirement.*

In fact, BACT is defined as an "emission limitation" that is "based on" the maximum degree of reduction in emissions. 40 C.F.R. § 52.21(b)(12). An operational requirement, such as a minimum control efficiency, may be prescribed instead, if the reviewing authority determines that the imposition of a numerical emission limitation is infeasible: "If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emission unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead, to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results." Id. This is not the case here; a numerical emission limitation for mercury is feasible.

ENV Comment #7.c.(6) (NPS #8; ENV #7.c.(4) and 7.c.(5))

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 WDEQ to impose a mercury BACT emission limit and other requirements reflective of at least 90 percent mercury reduction at Dry Fork, especially if WDEQ imposes this mercury reduction requirement over a long averaging time as has been typical in recent PSD permits.

Response: *See responses to NPS Comment #8 (BACT for mercury) and ENV Comments 7.c(4) and 7.c(5) (control requirements for mercury).*

ENV Comment #7.d. (EPA #1 and 2)

WDEQ must impose BACT limits for VOCs, sulfuric acid mist, and ammonia.

Response: *See responses to EPA Comments #1 and #2.*

ENV Comment #7.e.

WDEQ failed to propose a visible emission limit reflective of BACT.

__Response:__ WDEQ has included the applicable requirements for the NSPS (20% opacity) and Basin is required to meet this emission standard. Further, Basin has already done BACT for constituents/precursors to opacity and, therefore, protections are already in place for opacity.

An agency may use opacity as an emission limitation, however, there is neither a federal requirement nor a state requirement to have an opacity limit other than that contained in the applicable NSPS regulations. The reference to opacity in the Wyoming definition of BACT, similar to the language in 40 C.F.R. § 52.21(b)(12), is contained within parentheses. This reference has been interpreted as <u>allowing</u> an opacity limit to be set as BACT, but does not require that such a limit be set. See, e.g., Kentucky Division for Air Quality, Response to Comments on the Title V Permit No. V-02-043 Revision 2, Louisville Gas and Electric Company (November 17, 2005) available at http://www.air.ky.gov/NR/rdonlyres/A6A5EE5A-E804-4830-AC33-F1B87187CB76/0/Comments_3905.pdf (last visited 6/4/07), at 23 (an agency may use opacity as an emission limitation); Missouri Department of Natural Resources, Comments and Responses on KCPL's Iatan PSD New Source Review Permit, Project No. 2005-05-062 available at https://www.dnr.mo.gov/env/apcp/docs/012006-019rtocdocument.pdf (last visited 6/4/07), at 38 (a BACT analysis is not required for opacity). As evidenced by previous permitting decisions, WDEQ has interpreted this language as not requiring an opacity limit to be set as BACT.

Further, the definition of BACT in the Clean Air Act does not include the parenthetical phrase in question. It simply states that BACT is an emission limitation for each pollutant subject to regulation. Since opacity is not a pollutant, there is not a statutory obligation to set an opacity limit. Opacity may be an indicator of particulate matter, fumes, gases or vapor, but it is not an independent pollutant to be regulated. See EPA Region V, Particulate Matter and Opacity (undated), available at http:www.epa.gov/region5/air/naaqs/opacity.htm (last visited 6/4/07) ("EPA and the states use opacity as a convenient surrogate for assessing mass emissions, as a means to assure effective particulate emissions control."). Opacity is the property for the absorption of light, an appropriate indicator for a variety of air pollution concerns, but not a regulated PSD pollutant. See id. ("Opacity is the amount of light which is blocked by a medium, like smoke or a tinted window. Opacity is a measurement and is usually stated as a percentage."). The regulated PSD pollutant PM/PM_{10} will be monitored by COMs. This will provide a continuous method for ensuring compliance with the particulate emissions standard.

ENV Comment #7.e.(2)

To ensure compliance, COMS must be required.

__Response:__ Basin plans to install COMs as part of the verification of compliance method for its PM_{10} limit.

ENV Comment #8 (NPS #11)

WY failed to propose a limit on total PM_{10} emissions (filterable plus condensable emissions). Such a limit is necessary to ensure that total, actual PM_{10} emissions are consistent with those used in the modeling to demonstrate compliance with the PM_{10} NAAQS, PSD increment, and visibility guidance.

Response: *See response to NPS Comment # 11.*

ENV Comment #9

WY regulations require consideration of $PM_{2.5}$ as a regulated pollutant, even if the federal program does not yet require consideration of $PM_{2.5}$ emissions.

Response: *Basin is following 1997 EPA guidance providing that sources are allowed to us PM_{10} as a surrogate for $PM_{2.5}$. John Seitz, "Interim Implementation for the New Source Review Requirements for $PM_{2.5}$," October 23, 1997. EPA's most receive final rule implementing $PM_{2.5}$ states that it will address $PM_{2.5}$ in the PSD program at a later date, and in the meantime the 1997 EPA guidance continues to apply. 71 Fed. Reg. 61144 (Oct. 7, 2006).*

Further, Basin has done BACT for precursors to $PM_{2.5}$ (NO_x, VOC, SO_2, ammonia), therefore $PM_{2.5}$ emissions will be controlled and limited by the permit limits in place for these $PM_{2.5}$ precursors.

ENV Comment #11

Basin Electric's modeling indicated violations of the 24-hour SO_2 increments at the Northern Cheyenne Indian Reservation ("NCIR") and that Dry Fork will contribute to the violations, and therefore the permit should be denied.

Response: *Basin Electric's initial permit application included the results of modeling of SO_2 increment consumption at all Class I areas, including the NCIR. For all Class I areas except NCIR, modeled impacts were below Class I significance levels (SILs) and therefore no cumulative modeling was required. Class I SILs, although not currently adopted as regulation, were proposed by the EPA in 1996, and have been used routinely since then as a threshold below which a project is deemed not to contribute to increment consumption—modeled impacts less than the significance levels do not trigger cumulative modeling of increment consumption.*

Initial modeling of Dry Fork impacts predicted impacts at the NCIR above the significance levels for the 3-hr and 24-hr Class I SO_2 increments, so cumulative modeling was done for the NCIR. For the purpose of cumulative modeling, all increment consuming sources were modeled conservatively at their allowable emission levels, except for Units 3 and 4 at the Colstrip power plant in Montana, which were modeled at the 90th percentile of actual emissions for 2003 and 2004. Cumulative modeling predicted no violations of the Class I increments at the NCIR. Permit Application at 8-26.

However, the WDEQ later requested Basin Electric to model increment consumption at the NCIR using permitted allowable emissions for Colstrip Units 3 & 4, instead of the 90th percentile of actual emissions. Basin Electric pointed out that under the PSD rules increment consumption was supposed to be based on actual emissions, not allowable emissions, but performed the requested modeling nonetheless. The results predicted exceedances of the 3-hr. and 24-hr. Class I SO_2 increments at the NCIR, but for all days on which exceedances were predicted, the Dry Fork contribution was less than the Class I SILs. June 2006 Response, at 2.

The Wyoming Division of Air Quality ("AQD" or "Division") did its own modeling of Dry Fork SO_2 increment consumption, with an expanded wind field, and concluded that the only instance in which model results exceeded the Class I SILs was for the 24-hr SO_2 increment at the NCIR. The AQD then did cumulative modeling of 24-hr SO_2 increment consumption, which predicted exceedances of the increment. However, consistent with the modeling done by Basin Electric, at the times and places where the model predicted increment exceedances, the contribution of Dry Fork did not exceed the 24-hr SILs. Therefore, the Division found that "the impacts from Dry Fork do not contribute significantly to any of the modeled SO_2 exceedances at the Northern Cheyenne Indian Reservation." Permit Application Analysis at 40.

ENV contend that the Division's finding was erroneous, because 1.) the Class I SILs proposed by EPA in 1996 were never adopted as final, and 2.) any impact from a source should be deemed to contribute to increment exceedances, no matter how insignificant (citing an EPA Region VIII letter to the North Dakota Department of Health). However, although Class I SILs have not been adopted as regulations, they routinely have been used to determine whether a new source would contribute to an increment exceedance.[6]

The concept of SILs is based on 40 C.F.R. § 51.165(b)(2), which provides that under the nonattainment new source review program, a source will be considered to cause or contribute to a NAAQS violation when the source would exceed specified significance levels "at any locality that does not or would not meet the applicable standard." Although no parallel rule was ever adopted under the PSD program, these significance levels are uniformly applied in Class II areas under PSD. See, e.g., EPA NSR Manual at 26-30 and Table 4 ("In the event that the maximum ambient impact of a proposed emissions increase is below the appropriate ambient air quality significance level for all locations and averaging times, a full impact analysis for that pollutant is not required by EPA. Consequently, a preliminary analysis which predicts an insignificant ambient impact everywhere is accepted by EPA as the required air quality analysis (NAAQS and PSD increments) for that pollutant.").

Agencies may use their discretion to allow de minimis exceptions to otherwise applicable requirements. "Categorical exemptions may also be permissible as an exercise of agency power, inherent in most statutory schemes, to overlook circumstances that in context may fairly be considered de minimis. It is commonplace, of course, that the law does not concern itself with trifling matters, and this principal (sic) has often found application in the administrative context.

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[6] *ENV also asserts that the cumulative Class I SO_2 increment modeling for the NCIR did not include all increment-consuming sources. They contend the Yellowstone Energy Limited Partnership facility and unidentified sources in North Dakota and near Billings, Montana should have been modeled, also. However, in determining the increment-consuming sources and inventories, Basin Electric properly relied on the information provided by the air regulatory agencies in the states of Wyoming, Montana, North Dakota and South Dakota—agencies which are charge with the responsibility for identifying increment-consuming sources and protecting PSD increments. It is the uniform practice of modeling consultants to obtain information regarding increment-consuming sources from state air regulatory agencies as the most authoritative sources of that information, and there is no basis for challenging the information provided by the four states in this case.*

Courts should be reluctant to apply the literal terms of a statute to mandate pointless expenditure of effort. As we wrote in District of Columbia v. Orleans, . . . 406 F.2d 957, 959 (1968) *'[t]he 'de minimis' doctrine that was developed to prevent trivial items from draining the time of the courts has room for sound application to administration by the Government of its regulatory programs . . . .'"* Alabama Power v. Costle, *363 F.2d 323, 360 (D.C. Cir. 1979). Under the PSD program, EPA has used that discretion to apply the nonattainment significance levels to PSD sources despite the lack of explicit insignificance levels in the PSD rules.*

ENV cite a letter from EPA Region VIII to the State of North Dakota (attachment 23 to the ENV comments) which states that the Region believed that any impact, not just one that is significant, at a receptor where the PSD increment is violated, should be considered to contribute to that violation.

However, the Region's belief is contrary to other authorities and to widespread practice under the PSD rules. See, e.g., National Park Service Preliminary Comments on the Greene Energy PSD Permit Application March 2005, at 6 ("If the predicted impacts are above the proposed EPA Class I significance levels, then the permit applicant must examine the cumulative impacts to determine if any PSD increment would be violated."); available at http://www.truthaboutgob.org/NPSGreene_TSD.doc. National Park Service Supplemental Technical Comments on the Intermountain Power Agency PSD Permit Application for the Addition of Unit 3 at Its Intermountain Power Plant, May 2004, at 8 (although cumulative modeling showed violations of the 3-hour Class I SO_2 increment, "this modeling also demonstrates that IPP-3's impact is below the Class I SIL at all receptors where a 3-hour Class I increment violation was modeled. Therefore, IPP-3 would not 'cause or contribute to' the modeled 3-hour Class I increment violation."). Exhibit 18. See also, EPA Regions IX's Ambient Air Quality Impact Report, (NSR 4-1-3, AZP 04-01) for the Desert Rock power plant, at 38, available at http://www.epa.gov/region09/air/permit/desertrock/AAQIR.pdf. ("The PSD regulations do not allow a project to make a 'significant' contribution to a violation of the NAAQS or of the PSD increment. That is, the applicant must show that its own impact is below the Significant Impact Level (SIL) or else show that there is no violation at locations where its impact is above the SIL.") Thus, in cases more recent than Region VIII's letter to North Dakota, both the NPS and EPA have supported the principle that if a source's contribution to a NAAQS or increment violation is less than the applicable SIL, it will not be viewed as contributing to the violation and the increment violation will not bar issuance of a permit.

Most recently, on May 24, 2007, EPA proposed a rule regarding PSD increment modeling. Prevention of Significant Deterioration New Source Review: Refinement of Increment Modeling Procedures, Proposed Rule, 72 Fed. Reg. 31372. In the preamble to the proposed rule, EPA reiterates that "[t]he proposed source is deemed to 'cause or contribute to' an increment violation if the modeling shows that the impact attributable to the source at the time and place of the violation is greater than the significant impact level." Id. at 31377-78, n.5.

As a practical matter, it would be anomalous to reject the use of SILs to judge whether a source contributes to an increment violation. If allowable emissions from Colstrip Units 3 & 4, Colstrip alone, without any contribution from any other source, were predicted to violate the SO_2 increment at the NCIR, one could shut down all other existing sources and refuse to issue a permit for Dry Fork or any other new project, and there would still be an increment violation.

The problem is with Colstrip, and therefore the solution must be with Colstrip. Because Colstrip is in Montana, Wyoming has no authority to compel emission reductions at Colstrip to cure the increment violation. If allowable emissions are used to determine increment consumption, and SILs cannot be used to determine whether a new Wyoming source contributes to an increment violation, Wyoming could be precluded from permitting any new major sources, even those that have de minimis impacts, and have no ability to fix the problem.

Modeled increment violations occur when allowable emissions from Colstrip are used. It is clear, however, that consumption of PSD increment is supposed to be based on actual emissions, not on allowable emissions. See, e.g., NSR Manual at C.48 ("For a PSD increment analysis, an estimate of the amount of increment consumed by existing point sources generally is based on increases in <u>*actual*</u> *emissions occurring since the minor source baseline date." (emphasis in original)); Requirements for Preparation, Adoption, and Submittal of Implementation Plans; Approval and Promulgation of Implementation Plans, Final Rule, 45 Fed Reg. 52676 (August 7, 1980) (after deliberating whether increment consumption should be based on actual or allowable emissions, "EPA has concluded that increment consumption and expansion should be based primarily on actual emissions increases and decreases, . . . ");* <u>*National Resources Defense Council v. EPA*</u>*, 937 F.2d 641,645, n.3 ("Once the PSD baseline date is triggered by the first PSD permit application in the area, all increases in actual emissions consume the permissible amount regardless of their source". (Citation omitted).*

When CH2M-Hill initially modeled cumulative SO_2 increment consumption, it used the 90th percentile level of actual emissions for each source. Although use of the 90th percentile of actual emissions is not specified in the EPA NSR Manual or the PSD rules, the 90th percentile was used by EPA Region VIII in modeling increment consumption in Class I areas in North Dakota. Dispersion Modeling of PSD Class I Increment Consumption in North Dakota and Northern Montana, May 2003, at 20, available at http://www.epa.gov/Region8/foia/ndair/NDMod050803.pdf. ("EPA continues to believe that, for a cumulative increment analysis such as this, the 90th percentile emission rate is the best representation of actual emissions.") The rationale for using the 90th percentile is that otherwise one assumes that all sources will operate at the 100% level simultaneously--an unrealistic assumption. Using the 90th percentile allows for a more realistic approximation of the highest combined emissions from increment consuming sources, and worst-case meteorology, that is likely to occur at one time, while avoiding overestimation of increment consumption.

In its Refinement of Increment Modeling Procedures, Proposed Rule, 72 Fed. Reg. 31372, EPA proposes to afford permitting agencies flexibility to model average short term rates (based on the average emission rate for the applicable averaging time that a pollutant was emitted during a consecutive 24-month period) in lieu of maximum rates. At 74-76. EPA notes that "[w]e understand it may not be reasonable to expect that increment-consuming sources will all be operating at their maximum short-term emissions rates at exactly the same time. If we were to require use of maximum emission rates in all instances, this would mandate that PSD modeling always be conducted using a scenario that is not necessarily representative of actual emissions or concentrations." Id. at 31390. Of course, this proposed rule has not been adopted, but it clearly indicates EPA's thinking that modeling of increment consumption should be done in a way that results in predictions that are consistent with reality, and are not unnecessarily *conservative. If average emissions are acceptable, certainly 90th percentile emissions are acceptable.*

That said, Basin does not rest solely on the results of modeling 90th percentile emissions from Colstrip. CH2M-Hill now has done additional cumulative modeling, using the maximum actual 24-hr emissions from Colstrip Units 3 & 4 rather than the 90th percentile. The results of that modeling are reported in CH2M-Hill, Dry Fork Cumulative 24-hour SO_2 Increment Analysis, June 20, 2007, Exhibit 26, and show that even using maximum actual emissions for Colstrip (and conservatively using potential or allowable emissions for other increment-consuming sources), there are no increment violations at the NCIR. Thus, using the worst case scenario envisioned in the PSD rules, there are no increment violations. Even if ENV were correct in asserting that SILs may not be used to determine whether Dry Fork contributes to a modeled increment violation, because there is no increment violation Dry Fork, by definition, is not causing or contribution to a violation.

ENV Comment #12

Basin Electric failed to conduct a complete analysis of the impact of Dry Fork emissions on soils and vegetation.

Response: *ENV assert there was no site-specific inventory of soils and vegetation and that Basin Electric relied blindly on the EPA's 1980 Screening Procedure in doing the soils and vegetation analysis. This is simply untrue, and misstates what in fact was done. EPA's 1980 Screening Procedure was not used. It appears the ENV have mistakenly incorporated generic comments previously submitted for other projects without checking to see if they apply here. A specific search was made for information regarding soils and vegetation in the area, consistent with EPA's NSR Manual. CH2M-Hill, Dry Fork Station Air Quality Impacts to Soils and Vegetation, June 20, 2007 (Soils and Vegetation Analysis) at 2, Exhibit 27; Permit Application, Sec. 7.8.2. The EPA NSR Manual provides that, except for sensitive species, it is appropriate to rely on modeled compliance with secondary NAAQS to demonstrate that plant species will be protected. EPA NSR Manual at D.5. For sensitive species, modeled concentrations of pollutants known to be potentially harmful were compared with concentrations at which harm might occur, and the comparison showed there would be no harm. Soils and Vegetation Analysis at 2. Pertinent pollutants emitted from Dry Fork were modeled and shown to be below federal modeling significance level, federal monitoring significance levels, or Wyoming Air Quality Standards. Soils and Vegetation Analysis at 2. ENV has pointed to no instance of a failure to analyze the impacts on a sensitive plant species of a pollutant known or suspected to have possibly harmful effects.*

ENV also contend that due to the lack of a site-specific inventory, it is impossible to know whether any endangered, threatened or sensitive species is located in or around the plant site. This is not the case. In addition to the analysis reported in the permit application, further inventories of the plant communities of the proposed power plant site and two transmission line route alternatives were conducted in 2005 and 2006, which included federally listed endangered and threatened species and BLM sensitive species in Campbell and Sheridan Counties. Soils and Vegetation Analysis at 3. A single listed plant species, Ute ladies'-tresses orchid, was identified as potentially occurring in the area, but the species was not observed during a field *survey in June 2006 and the Dry Fork Station site does not include suitable habitat for the species. Soils and Vegetation Analysis at 3. Although the literature lists many existing and potential threats to this species, none is related to air quality. Soils information was researched, and no sensitive soils were identified in the area. Soils in the area are typically alkaline and would not be sensitive to acidic deposition or impacts from the Dry Fork Station. Soils and Vegetation Analysis at 4.*

ENV rely heavily on <u>In re Indeck Elwood, LLC</u>, 13 E.A.D ___, EAB PSD Appeal No. 03-04 (Sept. 27, 2006). However, unlike Dry Fork, the Indeck-Elwood facility was adjacent to a national prairie preserve, the Midewin National Tall Grass Prairie, and federal and state agencies had commented that air emissions from the facility would adversely impact or jeopardize listed or sensitive species. The message from the EAB in Indeck-Elwood was that the proximity of Midewin, coupled with the state agency's reliance on the EPA's 1980 Screening Procedure (with which the EAB took issue), required remand for further analysis of soils and vegetation. Id., slip op. at 41-52. As noted above, there was no reliance in this case on the EPA's 1980 Screening Procedure and there is no national preserve next door. The soils and vegetation analysis for Dry Fork was done in accordance with the EPA NSR Manual—the process favored by the EAB in <u>Indeck-Elwood</u>. Id.

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