BEFORE THE ENVIRONMENTAL QUALITY COUNCIL
OF THE STATE OF WYOMING

IN THE MATTER OF:	)	
BASIN ELECTRIC POWER COOPERATIVE	)	Docket No. 07-2801
DRY FORK STATION,	)	Presiding Officer,
AIR PERMIT CT–4631	)	F. David Searle
	)	

EXPERT REPORT OF RANAJIT SAHU ON BEHALF OF PROTESTANTS

I. EXPERIENCE AND QUALIFICATIONS

1. I have a Bachelor of Technology degree, with Honors (B.Tech (Hons.)) from the Indian Institute of Technology (IIT), a Masters of Science (Mechanical Engineering) degree and a Doctorate in Philosophy (Ph.D), the latter two from the California Institute of Technology (Caltech).

2. I have over seventeen years of experience in the fields of environmental, mechanical, and chemical engineering including: program and project management services as well as design and specification of pollution control equipment. In that time, I have successfully managed and executed numerous projects. This includes basic and applied research projects, design projects, regulatory compliance projects, permitting projects, energy studies, risk assessment projects, and projects involving the communication of environmental data and information to the public.

3. I have provided and continue to provide consulting services to numerous private sector, public sector and public interest group clients. My clients over the past seventeen years include various steel mills, petroleum refineries, cement companies, aerospace companies, power generation facilities, lawn and garden equipment manufacturers, spa manufacturers, chemical distribution facilities, and various entities in the public sector including the Environmental Protection Agency, the United States

Department of Justice, California Department of Toxics Substances Control (DTSC), various municipalities, etc. I have performed projects in over 45 states, numerous local jurisdictions and internationally.

4. In addition to consulting, I have taught and continue to teach numerous courses in several Southern California universities including University of California Los Angeles (air pollution), University of California Riverside (air pollution, process hazard analysis), and Loyola Marymount University (air pollution, risk assessment, hazardous waste management) for the past fifteen years.

5. Finally, I have and continue to provide expert witness services in a number of environmental areas discussed above in both state and Federal courts as well as before administrative bodies. For details, please see my resume provided in Attachment A. My fee as an expert witness is $100 per hour ($125 per hour for depositions and trial testimony).

II. DRY FORK STATION AIR PERMIT

6. For the purposes of this report I have reviewed several documents, as cited in the footnotes contained in this report. My understanding of the issues pertaining to the Dry Fork Station (DFS) are based on my review of these documents. My understanding of general issues pertaining to the power plant and emissions therefrom are based on my educational and professional background as well as professional experience as discussed briefly above and in my resume provided in Attachment A.

7. On October 15, 2007, the Wyoming Department of Environmental Quality, Division of Air Quality (WDEQ-DAQ) issued a permit to construct (#CT-4631) to Basin Electric Power Cooperative (BEPC) to allow the construction of a coal fired electric

generating station known as the Dry Fork Station, located near Gillette, Campbell County, Wyoming.[1] Among other items, this station will consist of one subcritical[2] pulverized coal (PC) boiler rated at 385 MW (net)/422 MW (gross)[3] along with associated air pollution control equipment to meet the permit limits stated in Condition 9 of the issued permit (reproduced below):

PC Boiler (ES1-01) Allowable Emissions

Pollutant	lb/MMBtu	lb/MW-hr	lb/hr	tpy
NO_X	0.05 (12 month rolling)	1.0 (30-day rolling)[1]	190.1 (30-day rolling)	832.4
SO_2	0.070 (12 month rolling)	1.4 (30-day rolling)[1]	380.1 (3-hr block) 285.1 (30-day rolling)	1165.4
PM/PM_{10}	0.012[2]	–	45.6	199.8
CO	0.15	–	570.2 (30-day rolling)	2497
Hg	–	97×10^{-6} (12 month rolling)[1]	–	0.16
H_2SO_4	0.0025	–	9.5	41.6
HF	–	–	2.62	11.5
VOC	0.0037	–	14.1	61.6
NH_3	–	–	10 ppm_v[3], 19.6 lb/hr	85.8

1 NSPS Subpart Da Limit
2 Filterable PM/PM_{10}
3 Dry Basis, 3% O_2

8. Once built and operational, the Dry Fork Station will likely remain operational for at least 50 years, if not longer.

9. I will address the following issues in this report: (a) choice of subcritical (as opposed to super-critical or ultra super-critical) technology for the power plant and its consequent impact on emissions from DFS; (b) lack of consideration of $PM_{2.5}$ as a criteria pollutant including lack of BACT determination for $PM_{2.5}$; and (c) improper determination of Best Available Control Technology (BACT) emission levels for several

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[1] Letter from Wyoming Department of Environmental Quality to Jerry Menge, Air Quality Program Coordinator for Basin Electric Power Cooperative re: Permit No. CT-4631 (October 15, 2007) (attached as Exhibit 1).

[2] See Basin Electric Power Cooperative's Response and Affirmative Defenses to the Protest and Petition for Hearing, Docket No. 07-2801, at Response #33 (filed Dec. 21, 2007) (attached as Exhibit 2).

[3] See Memorandum from Sargent & Lundy, LLC re: Subcritical-Supercritical Boiler Comparison, at p. 1 (June 11, 2007) ("[T]he 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.") (attached as Exhibit 3).

pollutants including NO_X, SO_2, and mercury. It is my opinion that numerous aspects of items (a) through (d) were not addressed or were improperly addressed by the WDEQ-DAQ, resulting in a flawed permit. Collectively, this flawed permit will allow significantly greater emissions, especially considering the long, future, operating time period of the DFS.

A. Subcritical vs. Super-critical Technology

10. The DFS design is a sub-critical steam cycle. From an engineering standpoint, super-critical and ultra super-critical steam cycle design plants have greater efficiencies – i.e., that they can generate the same amount of electrical power from lesser quantity of coal burned in the boiler—than sub-critical designs.[4] For a description of the differences between super-critical and sub-critical cycles, see the technical memorandum prepared for BEPC by Sargent and Lundy.[5] Since pollutant emissions are directly proportional to the amount of coal burned, plants employing more efficient steam cycles will produce fewer emissions, on a per unit of power generated, all other things (i.e., type of fuel) being the same. Super-critical technologies as well as ultra super critical technologies are not new or experimental. Super-critical technologies have been used since the 1960s or earlier in the U.S. and in other countries such as Japan and Germany. All of the major boiler and turbine suppliers provide these technologies. These include Babcock and Wilcox, Alstom, Siemens Westinghouse, General Electric, Toshiba, and Mitsubishi.

[4] Review of Potential Efficiency Improvements at Coal-Fired Power Plants (April 17, 2001), available at http://www.cier.umd.edu/RGGI/documents/Stakeholder%20Comments/Data_coaleff_epa_2001.pdf (attached as Exhibit 4).
[5] Memo. from Sargent & Lundy, *supra* note 3.

11. It is my opinion that the BEPC and WDEQ-DAQ have not critically examined this issue and have erred in refusing to consider the use of super-critical technology for the DFS. BEPC's stated basis for this refusal is noted as follows:

> "…[S]ubstitution of a supercritical or ultrasupercritical boiler for the subcritical boiler at the DFS would be a fundamental redesign and redefinition of the project and therefore would not constitute BACT for control of pollutants from the DFS. Supercritical units have seldom been used for boilers smaller than 500 MW, and boilers below that size are not readily commercially available. The analysis performed by BEPC's engineering consultant and independently reviewed and accepted by DEQ estimated that, considering all factors, a supercritical unit would not provide a net efficiency gain for a unit the size of the DFS boiler and would cost more to construct. Therefore, at DFS, a supercritical unit is not only a redesign and redefinition of the project, it is not the Best Available Control Technology."[6]

It is my opinion that these conclusions are incorrect.

12. Super-critical or ultra super-critical technology would not constitute a "fundamental redesign and redefinition of the project."[7] All three technologies rely on pulverized coal (PC) combustion in boilers, which results in producing hot steam, which later expands in turbines, ultimately producing electrical power. The differences relate to the pressures and temperatures that the steam is produced at, prior to being sent to the turbine. It is the creation of higher pressure/temperature steam in the boiler, which later expands in the turbine, that creates the higher cycle efficiencies for super-critical and ultra super critical technology, as compared to sub-critical. Of course, in order to

[6] See Basin Electric Power Cooperative's Response and Affirmative Defenses, *supra* note 2, at Response #34; see also Wyoming Department of Environmental Quality, Division of Air Quality, In the Matter of a Permit Application (AP-3546) From Basin Electric Power Cooperative to Construct a 385 MW Pulverized Coal Fired Electric Generating Facility To Be Known As Dry Fork Station, at p. 11-12 (Response to Comments IV.6) (attached as Exhibit 5).

[7] WDEQ-DAQ does not explain the standard by which it can claim that super-critical technology is "fundamental redesign and redefinition." However, calling these "fundamentally" different is to use a standard so low, as to be meaningless. By this standard, using two different sub-critical boiler/turbine designs from two different manufacturers would have to also be judged involving "fundamental redesign and redefinition."

generate and accommodate these higher temperatures and pressures, boilers and turbines have to be designed with different materials and the like. But to call this a fundamental redesign is flawed. All three technologies are similar, differing only to the degree to which steam conditions change at boiler exit.

13. Sargent and Lundy, BEPC's engineers, have stated that "[T]urbines designed for use in supercritical applications are fundamentally similar to turbine designs used in subcritical power plants,"[8] and that "[T]here are no significant differences between the IP [intermediate pressure] and LP [low pressure] turbine sections of a supercritical and subcritical plant."[9] Also, in at least one other recent permitting context, a coal fired utility (Utah Associated Municipal Power Systems, UAMPS) and a state agency (Utah DEQ) have concluded that subcritical and supercritical systems are equivalent technologies.[10]

14. BEPC (in the excerpt above) and WDEQ-DAQ[11] cite, as support, a study done by the firm CH2M Hill for BEPC in which CH2M Hill compared various technologies, leading to the selection of the sub-critical technology chosen by BEPC. I note that this study appears to have been done when the size of the DFS plant was thought to be 250 MW. Even so, this study does not support the BEPC's position on "fundamental redesign and redefinition." It also does not similarly support the WDEQ's

[8] Memo. from Sargent & Lundy, *supra* note 3.
[9] Id.
[10] UAMPS initially proposed to build a subcritical unit at its Delta, UT plant but later (after permit issuance) changed the design to a supercritical unit. See Letter from UAMPS to Rick Sprott, Utah Department of Environmental Quality, Division of Air Quality re: Engineering and Procurement of IPSC Unit 3 Boiler-Supercritical (August 4, 2006) (attached as Exhibit 6); Letter from Rick Sprott, Utah Department of Environmental Quality, Division of Air Quality to Doug Hunter, Chairman, UAMPS re: Equivalency Determination for the Intermountain Power Service Corporation (IPSC) Unit 3 Pulverized Coal (PC) Fired Boiler (August 17, 2006) (attached as Exhibit 7). Utah DEQ's reasoning for not requiring a new BACT analysis was that the supercritical unit proposed was "equivalent" to the subcritical one.
[11] See In the Matter of a Permit Application (AP-3546), *supra* note 6, at p. 11-12 (Response to Comments IV.6). Actually, WDEQ's assertion that the CH2M Hill study "…discusses the efficiency improvements with supercritical boilers…" is incorrect. That analysis was presented in the Sargent and Lundy analysis.

position that consideration of supercritical technology is tantamount to redefining the source.[12] The over-50 page CH2M Hill study differentiates the various technologies that it reviewed into four categories: pulverized coal (PC), CFB, and two different flavors of IGCC. The distinction, within the PC category, relating to sub-critical as opposed to super-critical, is discussed in under one page. The study does not claim that these are fundamentally different technologies. In fact, discussing supercritical boilers, the study notes that "[T]he additional capital cost for a supercritical steam cycle is typically only justified by the efficiency improvement for PC units of 350 MW and larger." As noted earlier, the DFS units is 422 MW.

15. Supercritical boilers are available for boilers smaller than 500 MW. I am aware of several currently operating power plants with supercritical boilers less than 500 MW. These include operating plants located at Nordjyllaend 3 in Denmark in 1998 (410 MW and efficiency of 47%), Avedore 2 in Denmark in 2001 (450 MW and efficiency of 48.2%),[13] and Genesee 3 in 2005 in Alberta, Canada (495 MW).[14] Sargent and Lundy's own documentation indicates that additional supercritical plants in this size range have been built and are operating. One of the vendors they contacted in 2005, Toshiba, indicated that they had supplied equipment for two units of 420 MW at the Callide Power Project in Australia and one unit of 450 MW at the Tarong Power Plant, also in Australia.[15] Siemens Westinghouse indicated to Sargent and Lundy that "a 400 MW

[12] Id.
[13] PowerGen Asia, Supercritical & Ultra-supercritical Power Plants (2004) (attached as Exibit 8).
[14] 495-MW Capacity Genesee Power Generating Station Phase 3: First Supercritical Pressure Coal-fired Power Plant in Canada, available at http://www.hitachi.us/supportingdocs/forbus/hpsa/technical_papers/r2004_03_113.pdf (attached as Exhibit 9).
[15] Memorandum from Sargent and Lundy, LLC, Summary of Recent Survey to Manufacturers of Steam Turbine-Generators Regarding Minimum Megawatt Size For A Supercritical Plant (March 2005) (attached as Exhibit 10).

gross steam turbine is achievable (they can go down to 300 MW with no problem)."[16] Siemens also indicated that "[S]omeone recently asked if there were any technical reasons that an ultrasupercritical (~4000 psia) cycle could not be used on a 400 MW application. There are no turbine design issues that would prohibit such an application." [17] Similarly, GE indicated that "300-400 MW supercritical units are possible."[18] Alstom indicated that "[T]echnically the lowest application for USC turbines is in the range from 200 MW and 400 MW."[19] Alstom also indicated to Sargent and Lundy that "[O]ur market experience would indicate that supercritical units are generally considered in the market beginning at around 350 MW."[20]

16. Finally, a supercritical unit would provide a net efficiency gain for a unit the size of the DFS. The Sargent and Lundy technical memorandum of June 11, 2007 relies on 2005 surveys of vendors to conclude that "[R]educed efficiency gains…will reduce the expected cycle efficiency improvements from the 1.5-2.0% range on larger units (500 MW or larger) to approximately one half that benefit as unit output is reduced down toward the 250 MW level."[21] BEPC and WDEQ-DAQ's interpretation of this was that "the increased efficiency would be less than one-half of one percent."[22] At another location, BEPC further interpreted this to find that supercritical would "not provide a net efficiency gain."[23]

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[16] Id.
[17] Id.
[18] Id.
[19] Id.
[20] Id.
[21] Id.
[22] Letter from Jerry Menge, Air Quality Program Coordinator, Basin Electric Power Cooperative to Chad Schlictemeier, NSR Program Manager, Department of Environmental Quality, Air Quality Division re: Follow Up Response to DEQ Question (June 15, 2007) (attached as Exhibit 11).
[23] See Basin Electric Power Cooperative's Response and Affirmative Defenses, *supra* note 2, at Response #34.

17. The efficiency comparison made by Sagent and Lundy is flawed because it was made assuming the DFS unit was going to be 250 MW (DFS was initially planned to be only 250 MW, but was later increased to 422 MW). Because DFS is actually a 422 MW plant, the decline in efficiency improvement from the 1.5-2.0% range for units 500 MW or larger will actually be less than it would be for a 250 MW plant. The main reason for the reduction in efficiency was the loss experienced in the first stage of the turbine – this loss would be much lower in going from a 500 to a 422 MW unit as compared to going from a 500 to a 250 MW unit. Furthermore, even at the 250 MW size, as the report shows, there is an efficiency benefit. Therefore, BEPC's conclusion that super-critical technology would provide no net efficiency gain is incorrect. And, WDEQ-DAQ's summary rejection of even the 0.5% efficiency gain is misguided. Any efficiency gain, no matter how small, equates to lower emissions on a daily basis and these emissions reductions are not negligible considering the projected life of the plant.

B. $PM_{2.5}$

17. The DFS air permit does not address emissions of a criteria pollutant, namely $PM_{2.5}$. $PM_{2.5}$ is a criteria pollutant with its own National Ambient Air Quality Standards (NAAQS) since 1997; therefore, it is a regulated New Source Review (NSR) pollutant. Its emissions cause serious health problems, and the DFS boiler will emit $PM_{2.5}$. Yet, there was no separate analysis conducted at any level for this pollutant. The permit does not contain a BACT-determined emission limitation or any other design, equipment, work practice or operational standard for $PM_{2.5}$. WDEQ-DAQ did not evaluate best available control technology for reducing $PM_{2.5}$ emissions, no preconstruction monitoring of current $PM_{2.5}$ concentrations was done, and no air quality

modeling was conducted to determine the impact of these $PM_{2.5}$ emissions on the area's compliance with the $PM_{2.5}$ NAAQS.

18. The reason provided by WDEQ-DAQ for not considering $PM_{2.5}$ is that another pollutant, namely PM_{10}, is a surrogate for $PM_{2.5}$.[24] PM_{10} and $PM_{2.5}$ denote difference size fractions of particulate matter. While PM_{10} represents particles that are 10 microns or smaller in aerodynamic diameter, $PM_{2.5}$ represents particles that are 2.5 microns or smaller in aerodynamic diameter. EPA has identified $PM_{2.5}$ as being particularly dangerous to human health and causing different environmental consequences than coarse particulates.[25] As a result of these findings, EPA promulgated separate and distinct national ambient air quality standards for $PM_{2.5}$.[26]

19. PM_{10} is a reliable surrogate for $PM_{2.5}$. As EPA has recognized, fine and coarse particulates ($PM_{2.5}$ and PM_{10}, respectively) "are generally associated with distinctly different source types and formation processes."[27] EPA has also recognized that "PM[2.5] also differs from PM[10] in terms of atmospheric dispersion characteristics, chemical composition, and contribution from regional transport."[28] Reliance on PM_{10} modeling as a surrogate for $PM_{2.5}$ is inadequate because $PM_{2.5}$ disperses generally much farther than does PM_{10}.

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[24] <u>See</u> In the Matter of a Permit Application (AP-3546), *supra* note 6, at p. 14 (Response to Comments IV.9).

[25] <u>See</u> National Ambient Air Quality Standards for Particulate Matter, Final Rule, 62 Fed. Reg. 38652, 38665 (July 18, 1997) (there are stronger links to the mortality and morbidity effects of particulate matter from exposure to $PM_{2.5}$ rather than PM_{10}); <u>see also</u> <u>id.</u> at 38666 (control efforts can be improved by defining size classes of particulate matter and fine and coarse fractions should be considered different classes of particles under the Clean Air Act); <u>see also</u> <u>id.</u> at 38667 (based on evidence from health studies and the inherent physical and chemical distinction between fine and coarse particulates, there is a proper basis to conclude that the two should be considered separate and have separate emission limits and standards).

[26] <u>Id.</u>

[27] Proposed Rule To Implement the Fine Particle National Ambient Air Quality Standards, 70 Fed. Reg. 65984, 65,992 (November 1, 2005).

[28] Clean Air Fine Particle Implementation Rule, 72 Fed. Reg. 20586, 20599 (April 25, 2007).

20. Accordingly, BACT for PM_{10} is not BACT for $PM_{2.5}$. Because the effectiveness of controls varies with respect to particulate size, it is necessary to address PM_{10} and $PM_{2.5}$ separately. In fact, control technologies for PM_{10} often do not provide for effective control of $PM_{2.5}$. This fact has been specifically recognized by EPA, which stated in the $PM_{2.5}$ implementation rule that "[i]n contrast to PM[10], EPA anticipates that achieving the NAAQS for PM[2.5] will generally require States to evaluate different sources for controls, to consider controls of one or more precursors in addition to direct PM emissions, and to adopt different control strategies."[29]

21. WYDEQ-DAQ accepts BEPC's choice of a fabric filter for control of PM_{10}, but never confronts the issue that the baghouse selected may not be effective or as effective at capturing fine particles, particularly around the 1 micron level. There is no discussion of the bags or filter media that are proposed to be used in the baghouse (where the filtering actually occurs) and how the efficiencies of these media change as a function of particle size. For example, EPA has been evaluating various filter media for many years now and has concluded that specific bag materials and coatings (e.g., PTFE or Teflon, in particular) from various vendors[30] are more appropriate for providing greater control efficiencies for fine particulate matter or PM 2.5.[31] Similarly, it is well know that wet electrostatic precipitators (wet ESP) are particularly suited to controlling PM2.5.[32]

[29] Id. at 20589.
[30] See, for example, EPA Test Program Verifies Performance of Gore® Filter Laminate press release from W.L. Gore, as an example of one such vendor. W.L. Gore & Associates, EPA Test Program Verifies Performance of Gore® Filter Laminate (October 2006) (attached as Exhibit 12).
[31] E.H. Pechan & Associates, Inc., Evaluation of Potential $PM_{2.5}$ Reductions By Improving Performance of Control Devices: Conclusions and Recommendations, Draft Report, at Section 5.2 (September 30, 2005) (attached as Exhibit 13).
[32] Altman, R., *et. al.*, *Power Engineering*, Wet Electrostatic Precipitation Demonstrating Promise for Fine Particulate Control – Part 1 (January 2001) (attached as Exhibit 14).

Recent developments with membrane wet ESPs show additional promise in this regard.[33] Therefore, wet electro static precipitators (ESP) and appropriate fabric filter materials should have been considered in the BACT analysis.

22. WDEQ-DAQ relies on memoranda issued by EPA to support the contention that it is not required to address $PM_{2.5}$ as a PSD pollutant.[34] This EPA guidance provided that sources would be allowed to use implementation of a PM_{10} program as a surrogate for meeting $PM_{2.5}$ NSR requirements. The purpose of that guidance was to provide time for the development of necessary tools to calculate the emissions of $PM_{2.5}$ and related precursors, adequate modeling techniques to project ambient impacts, and $PM_{2.5}$ monitoring sites.[35] As EPA affirmed in its recently issued implementation rule for $PM_{2.5}$, in the decade since EPA issued the Seitz Memo, concerns about monitoring and modeling $PM_{2.5}$ have been largely resolved.[36] $PM_{2.5}$ monitoring stations have been in operation for many years; measurement methods are in place; and adequate modeling techniques have been developed.

23. With regard to measurement methods at the source, which are of concern in the BACT context, EPA has issued Conditional Test Method 40 (CTM-040) for filterable $PM_{2.5}$.[37] While this is not yet a promulgated test method, it is based on Method

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[33] Caine, J. & Hardik Shah, Membrane WESP – A Lower Cost Technology To Reduce $PM_{2.5}$, SO_3, and Hg^{+2} Emissions (2006) (attached as Exhibit 15).
[34] See In the Matter of a Permit Application (AP-3546), *supra* note 6, at p. 14 (Response to Comments IV.9) (citing Memorandum from John S. Seitz, Director, EPA Office of Air Quality Planning & Standards re: Interim Implementation of New Source Review Requirements for $PM_{2.5}$ (Oct. 23, 1997) (the "Seitz Memo") (attached as Exhibit 16)); Memorandum from Stephen D. Page, Director re: Implementation of New Source Review Requirements in PM-2.5 Nonattainment Areas (the "Page $PM_{2.5}$ Memo") (attached as Exhibit 17).
[35] 70 Fed. Reg. 65984, *supra* note 27, at 66043.
[36] 72 Fed. Reg. 20586, *supra* note 28.
[37] "Filterable" refers to that fraction of the particulate matter (of whatever size fraction) that is captured by a filter placed in the exhaust gas path. Sometimes, this is referred to as the "front half" catch. "Condensible" refers to that fraction of particulate matter that is not captured by a filter.

201A, a well-established test method that has been formally adopted by EPA.[38] Further, Method 202 is in regular use to measure condensable PM. EPA is now preparing to release a modified version of this method to improve its accuracy and repeatability. EPA is also developing a test method capable of measuring both filterable and condensable particulate. The draft of this method, known as the "dilution sampling method," is available on the EPA website as CTM-039.[39] In short, there are reliable, field-tested methods available right now to measure $PM_{2.5}$ at the source and even better methods are already available in draft form (and likely to become final before the DFS boiler begins operation). In addition, established models for analyzing $PM_{2.5}$ impacts do exist. Two models have been approved at different points in time for $PM_{2.5}$ modeling: the ISC model[40] and the AERMOD model.[41]

24. Other states are beginning to change their treatment of $PM_{2.5}$ in their NSR/PSD programs. For example, Connecticut recently issued its "Interim $PM_{2.5}$ New Source Review Modeling Policy and Procedures" document, which states that "for permit applications subject to this policy, a demonstration of compliance with the PM_{10} NAAQS will no longer serve as a surrogate for compliance with the $PM_{2.5}$ NAAQS. Instead, NSR

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[38] 72 Fed. Reg. 20586, *supra* note 28, at 20653 ("we believe that further validation of this method is unwarranted since the technology and procedures are based upon the same as evaluated for promulgated Method 201A").

[39] See http://www.epa.gov/ttn/emc/ctm.html.

[40] See Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Final Rule, 61 Fed. Reg. 41838, 41850 (August 12, 1996).

[41] See Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Final Rule 70 Fed. Reg. 68218, 68253 (November 9, 2005) (adopting AERMOD as the "preferred model").

permit applicants must consider $PM_{2.5}$ as a criteria pollutant and address it in preparing an application."[42] Connecticut's policy covers all NSR/PSD modeling and BACT analyses.

C. BACT Limits

25. For each pollutant subject to regulation, WYDEQ-DAQ must adopt "an emission limitation . . . based on the maximum degree of reduction . . . achievable for [the] source."[43] The approved NO_x, SO_2, and mercury BACT permit limits do not represent the maximum degree of reduction that can be achieved while generating electricity from coal.

1. Averaging times

26. Section 302(k) of the Clean Air Act defines the term "emissions limitation" as a limitation on emissions of air pollutants "on a continuous basis."[44] Accordingly, BACT must continuously limit emissions of air pollutants. The proposed BACT limits for NOx of 0.05 lb/MMBtu (12 month rolling) and for SO_2 of 0.070 lb/MMBtu (12 month rolling) do not meet this standard. Although WDEQ-DAQ added 30-day rolling limits for NOx and SO_2 in the permit (as well as a 3-hour rolling limit for SO_2) in response to adverse comments by the Environmental Protection Agency and others,[45] these mass-based lb/hr limits are not BACT.

27. BACT requires that the boiler be controlled to the maximum extent at all times. In other words, efficiency for control equipment, such as low NOx burners and selective catalytic reduction (SCR) or scrubbers, must be maintained at the highest levels

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[42] Memorandum from Gina McCarthy, Commissioner, Connecticut Department of Environmental Protection re: CTDEP Interim PM2.5 New Source Review Modeling Policy And Procedures (August 21, 2007) (attached as Exhibit 18).
[43] Wyoming Air Quality Standards and Regulations, Ch. 6 § 4(a).
[44] 42 U.S.C. § 7602.
[45] Letter from Wyoming Department of Environmental Quality to Jerry Menge, *supra* note 1, at p. 2-3 ¶ 9.

at all times. Having a mass-based limit (such as the lb/hour limits) in the permit does not ensure that the controls will be operating at their maximum level at all times. To ensure that controls will be operating at their maximum level at all times, the permit must include control efficiency values for the control equipment such as the SCR or scrubbers or by lb/MMBtu values on a short term basis.

28. For example, the NO_x mass limit of 190.1 lb/hr translates to an emission rate of 0.05 lb/MMBtu, assuming that the heat input to the boiler is at its design maximum level of 3801 MMBtu/hr (3801 MMBtu/hr x 0.05 lb/MMBtu = 190 lb/hr). However, for time periods when the boiler will not be running at its design maximum heat input rate (which likely to happen frequently since no boiler, in my experience, runs at its maximum rated capacity at all times), the NO_x mass limit of 190.1 lb/hr equates to a NO_x emission rate greater than 0.05 lb/MMBtu. For example, if the boiler is operating at 50% of its design maximum heat input (3801 MMBtu/hr X 50% = 1900.5 MMBtu/hr), the mass limit of 190.1 lb/hr means that the NO_x emission rate can be 0.10 lb/MMBtu. (190 lb/hr / 1900.5 MMBtu/hr = 0.10 lb/MMBtu).

29. The 0.05 lb/MMBtu (or lower, as discussed below) NO_x BACT limit for Dry Fork must apply on a shorter averaging time than the proposed 12-month rolling average limit. Not only is it important for the averaging time of the BACT limit to be equal to or shorter than the most stringent averaging time of the NAAQS or PSD standards (which in the case of NO_x means at least a 24-hour averaging time to be consistent with the Class I area visibility modeling), but the averaging time of the BACT limit must be consistent with the BACT requirement that the limit be based on the maximum degree of reduction that can be achieved. A long averaging period such as the

WDEQ-DAQ's proposed 12-month rolling average does not require that DFS operate its NO_x pollution control equipment in a manner consistent with achieving the maximum reduction in emissions on a continuous basis.

30. WDEQ-DAQ's SO_2 permit limits suffer from the same flaw. The 12-month rolling limit of 0.07 lb/MMBtu is not BACT because the averaging time is too long. In addition, the short-term mass limits (i.e., 380.1 lb/hr for 3-hr and 285.1 lb/hr for 30-day) are also not BACT because they do not ensure the maximum degree of control over time for the reasons discussed in the context of NO_x mass limits.

2. NO_x BACT limit

31. The proposed NO_x emissions limit of 0.05 lb/MMBtu (12 month rolling) is not BACT for this facility. Lower levels of NO_x BACT are possible with the selected control technologies. NO_x emissions at the stack from the boiler are the product of the following two factors: (a) the NO_x emissions that are generated in the boiler itself, i.e., at the burners and using other techniques such as over-fire air, etc. and (b) the reduction of NO_x emissions that can occur in control equipment outside the boiler (such as SCR). BACT requires that each of these factors be considered in ensuring that the stack NO_x emissions meet BACT. The NO_x emissions in the boiler should be minimized to the greatest extent possible by using the lowest-emitting burner designs (sometimes referred to as low-NO_x burners or ultra low-NO_x burners) and associated burner air management practices (such as the type and amount of over-fire air used, etc.). Thereafter, once the NO_x emissions from the boiler are minimized, the post-boiler NO_x reduction should be

maximized by utilizing SCR with the highest efficiency. The DFS BACT analysis does not distinguish them separately.[46]

32. With respect to the emissions that can be expected from the boiler itself, BEPC assumes a rate of 0.20 to 0.25 lb/MMBtu.[47] However, lower NO_x emission rates can be achieved with current state-of-the-art low NO_x burners and overfire air. For example, available vendor information for ultra low NO_x burners with overfire air indicates that boiler outlet NO_x emission rates of 0.17 lb/MMBtu or lower can be met at boilers burning subbituminous coal from the Powder River Basin.[48] Another study conducted by Babcock & Wilcox at tangentially-fired units burning subbituminous Powder River Basin coal showed NO_x emission rates with ultra low NO_x burners and overfire air that were generally less than 0.13 lb/MMBtu.[49] BEPC has indicated that the planned PC boiler at DFS will be either tangentially-fired or wall-fired.[50] Even with a wall-fired boiler burning subbituminous coal, similar low NO_x emission rates have been met with current state-of-the-art low NO_x burners and overfire air. For example, a study conducted at a 600 MW wall-fired subbituminous coal burning boiler found that NO_x

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[46] WDEQ-DAQ apparently evaluated entries in the EPA's RACT/BACT/LAER Clearinghouse and evaluated actual emissions data from several Texas coal-fired electrical generating units to determine emission rates reflective of NO_x BACT for DFS. Consideration of this type of data is important in a BACT determination, but WYDEQ should have also gathered and considered other available data on pollution reduction capabilities from control technology vendors, consultants, and technical journals and reports. See EPA, New Source Review Workshop Manual, at B.11 (Draft Oct. 1990). WDEQ-DAQ did not critically evaluate the data it did collect. For example, for the Texas plants, WDEQ-DAQ did not establish whether these plants were running under conditions that minimized NO_x formation to the lowest achievable level before being chosen for comparison. At a minimum, without such analysis, further comparisons to this data are meaningless for the purpose of establishing BACT.

[47] Letter from Jerry Menge, Air Quality Program Coordinator, Basin Electric Power Cooperative re: Application for Permit to Construct Dry Fork Station Project, at p. 2-8 (Table 2-4) (November 10, 2005) (attached as Exhibit 19).

[48] See Bryk, S.A. *et al.*, First Commercial Application of DRB-4Z™ Ultra-Low NO_x Coal-Fired Burner, presented to POWER-GEN International 2000 in Orlando, FL (November 14-16, 2000) (attached as Exhibit 20).

[49] See Whitfield, T. *et al.*, Comparison of NO_x Emissions Reductions with PRB and Bituminous Coals in 900 MW Tangentially Fired Boilers, presented to EPRI-DOE-EPA-AWMA, Combined Power Plant Air Pollutant Control Mega Symposium in Washington, DC (May 19-22, 2003), at 8 (attached as Exhibit 21).

[50] See Application for Permit to Construct Dry Fork Station Project, *supra* note 47, at p. 2-5.

emission rates of 0.15 lb/MMBtu or lower (as low as 0.138 lb/MMBtu) were achieved with Low NO_x Dual Air Zone CCV® Burners and overfire air.[51] So, the assumption that the boiler NO_x emissions at DFS will be around 0.25 lb/MMBtu[52] means that NO_x emissions from the boiler are not minimized, contrary to BACT.

33. WDEQ-DAQ also did not evaluate the maximum degree of NO_x reduction that can be achieved with the control system (i.e., SCR) after the boiler. BEPC effectively assumes that the SCR will control NO_x to 80%.[53] The basis for this 80% assumption is not critically examined by WDEQ-DAQ, however. SCR systems can, today, (and have been for at least the last five plus years) been able to reduce NO_x emissions by 90% or more. According to Babcock & Wilcox, commercial SCR installations have shown that 90% NO_x reductions can be achieved with low ammonia slip.[54] Indeed, Babcock & Wilcox states that up to 95% NO_x control can be achieved with SCR. Every major SCR vendor, such as Haldor Topsoe, Hitachi, Cormetech, etc., will guarantee SCR at a minimum 90% reduction efficiency, in my opinion.

34. Combining the discussion above, BEPC and WDEQ-DAQ have failed to analyze why a combination of low NO burners, emitting 0.15 lb/MMBtu, in combination with SCR (even at 90% efficiency) is not the top technology. This combination would result in a NO emission limit of 0.015 lb/MMBtu, which is over three times lower than

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[51] See Penterson, Craig A. and Kenneth R. Hules, Reducing NO_x Emissions to Below 0.15 lb/10^6 Btu on a 600 MW Utility Boiler with Combustion Control Only, presented to EPRI-DOE-EPA-AWMA, Combined Power Plant Air Pollutant Control Mega Symposium in Washington, DC (May 19-22, 2003) (attached as Exhibit 22).

[52] See Application for Permit to Construct Dry Fork Station Project, *supra* note 47, at Section 5.2.4, p. 5-11 to 5-13.

[53] Since the NO_x emissions at the inlet to the boiler are assumed to be 0.25 lb/MMBtu (id.), the SCR has to be 80% efficient in order to meet the permit limit of 0.05 lb/MMBtu.

[54] See Bielawski, G.T., *et al.*, How Low Can We Go? Controlling Emissions in New Coal-Fired Power Plants, presented to the U.S. EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Symposium: "The Mega Symposium," in Chicago, IL (August 20-23, 2001) (attached as Exhibit 23).

the current permit limit. In addition, there are many other potential permit limit values between 0.015 lb/MMBtu and 0.05 lb/MMBtu that could have been – but were not examined.

3. SO_2 BACT Limit

35. It is my opinion that the BACT limits for SO_2 are flawed because they are too high and wet scrubber technology was improperly rejected during the BACT analysis process.

36. The initial permit application for this plant considered and rejected wet scrubbing (or wet flue gas desulfurization or "wet-FGD") as BACT based on its higher incremental cost effectiveness (in $/ton) as compared to dry scrubbing. Cost effectiveness is a ratio of cost to benefit (tons of pollutant reduced). Thus, if either costs are estimated as too high or benefits are estimated as too low, the cost-effectiveness metric will be numerically higher. In the permit application, it was assumed that: (a) the average coal sulfur content was 0.33% and (b) the control efficiency for wet FGD is 89%.[55] Both of the assumptions are flawed and result in an emissions limit that is too high and an improper rejection of wet-FGD based on an estimated benefit that it is too low.

37. In its March 3, 2006 response to WDEQ-DAQ Completeness Review, BEPC indicated that the maximum sulfur content of its coal was 0.47%.[56] The cost-effectiveness calculations should have been conducted assuming coal sulfur at this value as opposed to the lower average or design value of 0.33%. This is customary, unless

[55] See Application for Permit to Construct Dry Fork Station Project, *supra* note 47, at Appendix F; Basin Electric Power Cooperative, Response to Wyoming Department of Environmental Quality Completeness Review December 21, 2005 (March 3, 2006) (attached as Exhibit 24). Cost information does not appear to have been obtained from vendors.
[56] See Response to Completeness Review, *supra* note 55.

BEPC is willing to take a permit limit, limiting the sulfur content in its coal to a maximum of 0.33%. By likely relying on the lower value of 0.33% as in the original permit application, the analysis underestimates the potential tons of SO_2 emissions reductions and makes the cost-effectiveness value seem larger than it is.[57]

38. WYDEQ-DAQ also relies on a flawed assumption that wet FGD SO_2 reduction efficiency is limited to 89%. As I will discuss below, all major vendors of wet FGD are presently able to guarantee control efficiencies of 99% SO2 reduction. Even assuming for purposes of argument that this level of SO_2 reduction will be challenging in the context of PRB low-sulfur coals, it is feasible to obtain at least 98% reduction using wet FGD. Of course, using 98% instead of 89% makes a tremendous difference (i.e., increase) in the tons reduced, thereby reducing the cost-effectiveness value.

39. That wet FGD can achieve 99% control efficiency (especially over a long averaging period such as 12 months, as in the DFS permit) even today and will become more and more the norm by the time this plant is built, is readily demonstrable. First, over twenty years ago in 1982, Mitchell power station Unit 33 (Alleghany Power), a 292-MW generating unit near Pittsburgh, was retrofitted with a magnesium-enhanced lime ("MEL") wet FGD system pursuant to a Consent Decree.[58] Data is available for four months during 1983 and 1984 for that unit. The daily average SO_2 emission rate was 0.009 lbs/MMBtu and the daily average SO_2 removal efficiency was 99.76%. The maximum monthly average during these four months was 0.029 lb/MMBtu,

[57] While there is likely to be some increased cost associated with a higher sulfur coal, it is my opinion that the benefit (i.e., more tons reduced) will outweigh the increased costs, leading to a lower cost-effectiveness value.

[58] See EPA Docket EPA-HQ-OAR-2005-0031-0123 (attached as Exhibit 25).

corresponding to a 99.72% SO_2 reduction. Thus, over 99% reduction of SO_2 was being achieved more than two decades ago.

40. Second, a 2003 paper discussing the actual operating performance of the Chiyoda JBR or CT-121 wet scrubber technology in Japan notes that SO_2 removal efficiency of greater than 99% was achieved for all load levels and that a "[s]table SO_2 removal efficiency of over 99 percent" was achieved.[59] Additionally, Chiyoda's experience list shows at least three instances of 99% removal.[60]

41. Third, Mitsubishi Heavy Industries ("MHI"), another reputable vendor of wet scrubbers has a design called the High Efficiency Double Contact Flow Scrubber ("DCFS"), which has achieved SO_2 removal efficiencies as high as 99.9%. A presentation on the DCFS scrubber highlights the fact that it can be designed to achieve SO_2 removal efficiencies as high as 99.9% on a unit that burns high sulfur coals without the use of buffer additives.[61] The manufacturer, MHI, guarantees SO_2 removal of 99.8%.[62] A 2004 paper discussing the DCFS scrubber technology notes that this technology was recently selected at least two years ago by TVA for their Paradise Plant Unit 3, which will start up in early 2007.[63] This paper also reports on several recent commercial operating successes with this technology "including super high

[59] Shimogama, Yasuhiko, *et al.*, Commercial Experience of the CT-121 FGD Plant for 700 MW Shinko-Kobe Electric Power Plant, Paper No. 27, presented at the MEGA Symposium in Washington DC (May 22, 2003) (attached as Exhibit 26).

[60] Burmeister & Wain Energy A/S, Flue Gas Desulphurization, available at http://www.bwe.dk/pdf/ref-11%20FGD.pdf (attached as Exhibit 27). Several U.S. companies such as American Electric Power (AEP) are currently installing the Chiyoda JBR scrubber. For example, AEP's Cardinal Units 1 & 2 with JBR scrubbers began operating in late 2007-early 2008.

[61] Klingspor, Dr. Jonas S., *et al.*, High Efficiency Double Contact Flow Scrubber for the U.S. FGD Market, Paper No. 135 l, presented at the MEGA Symposium in Washington DC (May 22, 2003) (attached as Exhibit 28).

[62] Id.

[63] Nakayama, Yoshio, *et al.*, Commercial Experience and Actual-Plant-Scale Test Facility of MHI Single Tower FGD, Paper No. 33, presented at the MEGA Symposium in Washington DC (August 30 – September 2, 2004) (attached as Exhibit 29).

desulfurization performance (*i.e.*, 99.9%) with a single absorber."[64] The paper also notes that the COSMO oil Yokkaichi unit is an outstanding example of high SO_2 removal by a single counter current DCFS. Commercial operation at COSMO began in 2003, and the FGD system has achieved a cumulative availability of 100 percent since startup. The system is designed at 99.5% and operates at 99.9% SO_2 removal efficiency.

42. Fourth, a different variant of the wet scrubber technology –FLOWPAC – has demonstrated an SO_2 removal efficiency of over 99%.[65] From November 2002 to March 2003, Karlshamn Unit 3 operated for 2152 continuous hours while firing a heavy fuel with an average sulfur content of 2.4%. The SO_2 emissions during this period were kept to 21 mg/Nm3, which is an SO_2 efficiency of 99.5% with an S efficiency of 99%. During this period the FGD system was 100% available.

43. Fifth, another vendor, Alstom, recently discussed high efficiency scrubbing on high sulfur fuels. As noted in the paper "[t]o date, the wet flue gas desulfurization system has achieved 100% availability while achieving the plant SO_2 emissions limits throughout the operating duration….as indicated…the WFGD system has achieved SO_2 removal efficiencies up to 99+% without the use of organic additives."[66]

44. Finally, the Coal Utilization Research Council within the Electric Power Research Institute (CURC/EPRI), of which most utilities are members, concluded in its September 2006 Roadmap that up to 99% SO_2 removal for FGD was commercially

[64] Id.

[65] Nolin, Kjell and Donald Schreyer, FLOWPAC – Major WFGD Advance in Flue Gas Contact, Paper No. 114, presented at the MEGA Symposium in Washington, DC (August 30 – September 2, 2004) (attached as Exhibit 30).

[66] Catalona, G., *et al.*, State of the Art Wet FGD System for High-Sulfur Fuels in Florina/Greece, Power Gen Europe (2005) (attached as Exhibit 31).

available in 2005.[67] The CURC/EPRI Roadmap also projects removals of up to 99.6% in 2010 and 99.9% in 2015.[68] Therefore, it is my opinion that since it is the object of BACT to achieve the "maximum degree of reduction" or the lowest emission rate, considering the collateral cost, environmental, and energy factors, each of these technologies should have been examined in detail, as required by the top down method.

45. It is my opinion that the BACT analysis for wet FGD should be redone as follows: (a) obtain cost and vendor guarantees and base the analysis on these guarantees; (b) include as permit conditions, key assumptions (such as coal sulfur content) of such analysis. I believe that this will show wet FGD to be a top control technology. And, doing so, assuming that 98% control is possible, the BACT limit should be far lower than the currently permit limit of 0.07 lb/MMBtu.

46. Likewise, appropriate analysis would affect the cost-effectiveness analysis. WYDEQ-DAQ concluded that the overall cost-effectiveness for wet FGD was $1450/ton and that the incremental cost effectiveness (as compared to dry scrubbing) was $13,157/ton reduced. While the former was acceptable, wet FGD was rejected because the incremental cost-effectiveness as compared to dry scrubbing was deemed too high.[69] It is my opinion that had the proper sulfur value (i.e., 0.47%) in coal and proper control efficiency (i.e., 98%, although, as I have shown above, even 99% is feasible), the overall and incremental cost effectiveness values would be as much as perhaps 10 times smaller

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[67] The CURC/EPRI Clean Coal Technology Roadmap (September 20, 2006) (attached as Exhibit 32).
[68] Id.
[69] See Response to Completeness Review, *supra* note 55 (stating "…[T]he March 10, 2006 analysis showed that the incremental cost-effectiveness of WFGD was $12,610 (at 0.07 lb/MMBtu)….per ton SO_2 removed compared to the SDA…Therefore, WFGD was eliminated from consideration as BACT based on economic impacts…"

than that calculated by BEPC and accepted by the WDEQ-DAQ.[70] This would result in overall cost effectiveness values likely below $200 per ton reduced and incremental cost-effectiveness values under $1,500 per ton reduced.

4. Mercury BACT limit

47. I could not find a BACT analysis for mercury in the record. WDEQ-DAQ's discussion relating to mercury is as follows:[71]

> __Response__ – Mercury emissions are limited by federal New Source Performance Standards (NSPS) to 0.000090 pounds per megawatt-hour. In addition, the permit requires installation and operation of Best Available Control Technology (BACT). Mercury controls for power plants are an emerging technology and the BACT emission level will be determined based on the results of a one year mercury optimization study to be performed at this facility. The permit requires a mercury control system to be installed and a one year mercury optimization study to commence within 90 days of initial startup of the boiler. The target emission level for this study is 20×10^{-6} (0.000020) pounds per megawatt-hour. The final BACT emission limit will be established based on the results of the study. Also see the responses to PRBRC et al. #7c.2, NPS #5e, and Basin Electric #3.

The mercury limit in the permit is noted as 97×10^{-6} lb/MW-hr, which is the same as the NSPS Subpart Da limit. The 97×10^{-6} limit is no limit at all because it is actually greater than the highest uncontrolled value of mercury emissions that BEPC has itself indicated is possible from this plant (96.6×10^{-6} lb/MW-hr).[72] Accordingly, it does not constitute BACT.

48. Aside from being unenforceable, the choice of even the "target emission level" for the optimization study of 20×10^{-6} lb/MW-hr is unexplained. It is not the lowest limit that is already required at another plant, burning sub-bituminous coal. I am

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[70] I could not conducted an exact calculation of the revised cost-effectiveness because I did not have all of the data to properly re-estimate the cost of the controls. I realize that the cost of WFGD would be greater at 98% efficiency as opposed to the assumed 89% efficiency; however, the record in this case is not clear as to the basis of the assumed WFGD costs (i.e., no vendor data).

[71] In the Matter of a Permit Application (AP-3546), *supra* note 6, at p. 2 (Analysis of Public Comments II.1).

[72] __See__ Basin Electric Power Cooperative Dry Fork Unit 1 PSD Permit Application, Response to Wyoming Department of Environmental Quality, Air Quality Division, Permit Application No. AP-3546 Completeness Review Dated May 3, 2006 (August 18, 2006) (attached as Exhibit 33).

aware that the mercury limit at the Walter Scott, Jr. Energy Center (previously known as the Council Bluffs Energy Center) is 1.7×10^{-6} lb/MMBtu.[73] Based on a maximum heat input rate of 7,675 MMBtu/hr and a gross rating of 870 MW, this unit has a heat rate of roughly 8.820 Btu/kWh. Thus, the 1.7×10^{-6} lb/MMBtu limit translates to a limit of 15×10^{-6} lb/MW-hr. This is 75% of the "target" level proposed by WDEQ-DAQ for the DFS.

[73] Iowa Dept. of Natural Resources, Permit 03-A-425-P (June 17, 2003) (attached as Exhibit 34).

I declare under penalty of perjury that the statements in this report are true and accurate to the best of my knowledge.

May 1, 2008 __________________________
Date Dr. Ranajit Sahu