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ENVIR. APPEALS BOARD

BEFORE THE ENVIRONMENTAL APPEALS BOARD
U.S. ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC

In Re Deseret Power Electric Cooperative)
PSD Permit Number OU-0002-04.00) PSD Appeal No. ____

PETITION FOR REVIEW AND REQUEST FOR ORAL ARGUMENT

INTRODUCTION

Pursuant to 40 C.F.R. § 124.19(a), Sierra Club petitions for review of the Prevention of Significant Deterioration ("PSD") Permit Number PSD-OU-0002-04.00 (the "Bonanza PSD Permit") issued by EPA Region 8 to Deseret Power Electric Cooperative ("Deseret") on August 30, 2007. A copy of the Bonanza PSD Permit is attached as Exhibit 1. Because the plant is located within the Uintah and Ourah Indian Reservation and these tribes do not have an EPA-approved tribal permitting program under the Clean Air Act, EPA is the responsible permitting authority.

The Bonanza PSD Permit authorizes construction of a new waste-coal-fired electric utility generating unit at the existing Bonanza power plant near Bonanza, Utah. Sierra Club contends that EPA erred by (a) not requiring, pursuant to Section 165(a)(4) of the Act, a BACT emission limit for carbon dioxide ("CO_2") emissions from the new Bonanza coal-fired unit, and (b) taking positions in this matter that are contrary to positions taken by the agency in another coal-fired power plant proceeding.

Sierra Club also requests oral argument in this matter. Oral argument would assist the Board in its deliberations on the issues presented by the case because the issues raised herein are issues of first impression for the Board and the EPA, are generally a source of significant public interest, and are of a nature such that oral argument would materially assist in their resolution.

THRESHOLD PROCEDURAL REQUIREMENTS

Sierra Club satisfies the threshold requirements for filing a petition for review under Part 124. Sierra Club has standing to petition for review of the permit decision because its members participated in the public comment period on the draft permit. 40 CFR §124.19(a). See comments filed by Tim Wagner on behalf of the Sierra Club, attached as Exhibit 2. The issues raised by Sierra Club here were either raised with EPA during the public comment period or are new issues resulting from the Supreme Court's decision in *Massachusetts v. Environmental Protection Agency*, 127 S.Ct. 1438 (2007), which was decided after the comment period closed and was therefore not reasonably ascertainable at the close of the public comment period. (EPA did acknowledge the *Massachusetts* decision in its permitting decision.) Consequently, the Board has jurisdiction to hear Sierra Club's timely request for review. 40 C.F.R. § 71.11(g).

ISSUE PRESENTED FOR REVIEW

Because carbon dioxide is a "pollutant subject to regulation" under the Clean Air Act, was EPA's failure to include in the Bonanza PSD Permit a best available control technology ("BACT") emission limit for carbon dioxide a clearly erroneous conclusion of law or an important policy consideration that the Board should review and reverse?

STATEMENT OF FACTS

Deseret proposes to construct a "major modification" to its existing Bonanza plant, as defined in PSD rules. See 40 CFR 52.21(b2). The proposed unit would include a circulating fluidized bed boiler, consisting of primary and secondary air fans, a combustor, a cyclone/solids separator, a superheater, an economizer, an air heater and an induced draft fan. EPA Statement of Basis at 7. The proposed unit would additionally require combustion and generating systems, an emergency generator, exhaust systems and pollution control equipment, coal and limestone material handling and storage systems, cooling water systems, and ash disposal systems. Id. The proposed unit would have a power output of up to 110 megawatts, bringing the overall Bonanza plant's total to approximately 610 megawatts. Id. at 6.

EPA issued a draft PSD permit on or about June 22, 2006. The comment period closed on July 29, 2006. On April 2, 2007, the U.S. Supreme Court handed down *Massachusetts v. EPA*, 127 S.Ct. 1438, where the Court held that "greenhouse gases fit well within the Clean Air Act's capacious definition of 'air pollutant.'" Id. at 1462. EPA subsequently issued the final Bonanza PSD Permit on August 30, 2007, without reopening the permit for public comment. EPA also released its Response to Comments on the same date. (Relevant excerpts from the Response to Comments are attached as Exhibit 3.) Sierra Club now petitions the Board for review of this permit and urges a remand because EPA failed to establish a BACT emission limit for CO_2, and acted arbitrarily and capriciously by taking positions in this matter that are contrary to positions taken by the agency in another coal-fired power plant proceeding.

ARGUMENT

I. THE BONANZA PSD PERMIT SHOULD BE REMANDED BECAUSE IT LACKS A CO_2 BACT EMISSION LIMIT.

The Clean Air Act prohibits the construction of a new major stationary source of air pollutants in areas designated as in attainment of the National Ambient Air Quality Standards except in accordance with a prevention of significant deterioration (PSD) construction permit. 42 U.S.C. § 7475(a); 40 C.F.R. §52.21(a)(2)(iii). Of relevance here is §165 of the Act, which requires that a PSD permit must include a BACT emission limit "for each pollutant subject to regulation under this chapter emitted from, or which results from" the facility (42 U.S.C. § 7475(a)(4)), language that EPA repeated in its implementing regulations: BACT is required for "any pollutant that otherwise is subject to regulation under the Act." 40 C.F.R. § 52.21(b)(50)((iv).

As described further below, carbon dioxide has been *regulated* under the Clean Air Act since 1993. And, on April 2, 2007, the Supreme Court held that carbon dioxide and other greenhouse gases are "pollutants" under the Clean Air Act. *Massachusetts v. EPA*, 127 S.Ct. at 1460.

Now having been definitively ruled a *pollutant*, CO_2 is accordingly a *regulated pollutant* under the Act, and EPA is required to impose a CO_2 BACT emission limit in the Bonanza PSD permit. The relevant provisions of the Act are plain and unambiguous on their face and leave no room for EPA to pick and choose which pollutants it prefers to deal with under Section 165.

A. Carbon Dioxide is a "Pollutant Subject to Regulation" Under the Act Because It Is Regulated Under Section 821 of the Clean Air Act.

Section 821(a) of the Act (42 U.S.C. 7651k note; Pub.L. 101-549; 104 Stat. 2699; emphasis added) provides:

> Monitoring. – The Administrator of the Environmental Protection Agency **shall promulgate regulations** within 18 months after the enactment of the Clean Air Act Amendments of 1990 **to require that all affected sources subject to the Title V of the Clean Air Act shall also monitor carbon dioxide emissions** according to the same timetable as in Sections 511(b) and (c). **The regulations shall require that such data shall be reported to the Administrator**. The provisions of Section 511(e) of Title V of the Clean Air Act shall apply for purposes of this section in the same manner and to the same extent as such provision applies to the monitoring and data referred to in Section 511.[1]

The language could not be clearer: In § 821 Congress ordered EPA "to promulgate regulations" requiring that hundreds of facilities covered by Title IV monitor and report their CO_2 emissions, and in §165, Congress required a BACT limit for "any pollutant subject to regulation" under the Act. The only possible reading of these two statutory mandates is that Congress intended that EPA apply BACT limits to CO_2 pursuant to §165.[2]

B. EPA's Interpretation of Section 165 is Completely Wrong and Entitled to no Deference

[1] According to the Reporter's notes, these references to Title V are meant to refer to Title IV, and the references to Section 511 are meant to refer to Section 412.
[2] EPA's §821 regulations, which were finalized on January 11, 1993, require CO_2 emissions monitoring (40 CFR §§75.1(b), 75.10(a)(3)); preparing and maintaining monitoring plans (40 CFR §75.33); maintaining records (40 CFR §75.57); and reporting such information to EPA, (40 CFR §§75.60 – 64). 40 CFR §75.5 prohibits operation in violation of these requirements and provides that a violation of any Part 75 requirement is a violation of the Act.

Obviously unhappy with the notion that these words mean what they plainly say, in refusing to impose a CO_2 BACT limit EPA insists that they must mean something completely different (Exhibit 3, p. 6; emphasis added):

> EPA continues to interpret the phrase 'subject to regulation under the Act' to refer to pollutants that are subject to **a statutory or regulatory provision that requires actual control of emissions of that pollutant.** Because EPA has not established a NAAQS or NSPS for CO2, classified CO2 as a Title VI substance, or otherwise regulated CO2 under any other provision of the Act, CO2 is not currently a "regulated NSR pollutant" as defined by EPA regulations.

In other words, EPA believes that in §165 Congress intended "regulation" to mean "a statutory or regulatory provision that requires actual control of emissions." Unfortunately, EPA provides neither a rationale nor any basis whatsoever for its novel interpretation of the word "regulation", and any rationale it eventually manages to conjure up to defend this position will run into some serious difficulty.

First, the most basic canon of statutory interpretation is that words should be given their plain meaning, and Webster's defines "regulation" as "an authoritative rule dealing with details or procedure; (b) a rule or order issued by an executive authority or regulatory agency of a government and having the force of law."

That should be the end of the matter: "It is well established that 'when the statute's language is plain, the sole function of the courts--at least where the disposition required by the text is not absurd--is to enforce it according to its terms.'" *Lamie v. United States Tr.*, 540 U.S. 526, 534 (2004). And, of course, the Supreme Court has already pointed out that information gathering, record keeping, and data publication rules are indisputably within the conventional understanding of "regulation." *Buckley v. Valeo*, 424 U.S. 1, 66-67 (1976)(record keeping and reporting requirements are regulation of political speech).

Given the plain language that Congress used, EPA can point to no ambiguity in the statute that would allow it to gloss the statutory text: "If the intent of Congress is clear, that is the end of the matter; for the court, as well as the agency, must give effect to the unambiguously expressed intent of Congress." *Chevron v. NRDC*, 467 U.S. 837, 842-843 (1984). To the extent that EPA tries to claim that it is interpreting its own regulation, as opposed to the statutory mandate, it would fare no better:

> [T]he existence of a parroting regulation does not change the fact that the question here is . . . the meaning of the statute. An agency does not acquire special authority to interpret its own words when, instead of using its expertise and experience to formulate a regulation, it has elected merely to paraphrase the statutory language."

Gonzales v. Oregon, 546 U.S. 243, 257 (2006).

Second, as the Supreme Court has repeatedly held, "generally, identical words used in different parts of the same statute are . . . presumed to have the same meaning." *Merrill Lynch, Pierce, Fenner & Smith, Inc. v. Dabit*, 547 U.S. 71, 86 (2006) (quoting *IBP, Inc. v. Alvarez*, 546 U.S. 21, 33-34 (2005). EPA has not – and could not -- offer any rationale to explain why "regulation" in § 821 means "regulation", but that "regulation" in §165 means "actual control of emissions". Indeed, the Act contains numerous other examples of Congress requiring regulations for many reasons aside from "actual control of emissions", including right in §165: "The review provided for in subsection (a) of this section shall be preceded by an analysis in accordance with regulations of the Administrator, promulgated under this subsection, . . . of the ambient air quality at the proposed site . . " 42 U.S.C. §7475(e)(1). *See also* 42 U.S.C. §7619(a)("the Administrator shall promulgate regulations establishing an air quality monitoring system throughout the United States . . .")

Third, in drafting the Clean Air Act Congress knew how to refer to "actual control of emissions" when it wanted to, and in fact created two separate terms of art for just such occasions, "emissions limitation" and "emissions standard": "The terms 'emission limitation' and 'emission standard' mean a requirement established by the State or the Administrator **which limits the quantity, rate or concentration of emissions of air pollutants** . . ." 42 U.S.C. § 7602(k)(emphasis added). Congress then used the terms "emission limitation" and "emission standard" throughout the Act (*see, e.g.*, 42 U.S.C. § 7651d(a)(1)("Each utility unit subject to an annual sulfur dioxide tonnage emission limitation under this section . . ."); 42 U.S.C. § 7412(f)(5)("The Administrator shall not be required to conduct any review under this subsection or promulgate emission limitations under this subsection . . ."); 42 U.S.C. § 7521(f)(2)("This percentage reduction shall be determined by comparing any proposed high altitude emission standards to high altitude emissions . . ."); 42 U.S.C. § 7617(a)(7)("any aircraft emission standard under section 7571 of this title.") Thus if Congress wanted to limit the applicability of §165 to those pollutants that were subject to such a standard or limitation, it certainly knew how to do so. But it did not do so in Section 165.

Finally, EPA's interpretation runs afoul of the holding in *Alabama Power Co. v. Costle*, 636 F.2d 323, 403 (D.C. Cir. 1979), which foreclosed such creative readings of the term "each pollutant subject to regulation" under the Act:

> The only administrative task apparently reserved to the Agency . . . is to identify those . . . pollutants subject to regulation under the Act which are thereby comprehended by the statute. The language of the Act does not limit the applicability of PSD only to one or several of the pollutants regulated under the Act,
>
> ... .the plain language of section 165 . . .in a litany of repetition, provides without qualification that each of its major substantive provisions shall be effective after 7 August 1977 with regard to each pollutant subject to regulation under the Act, or with regard to any "applicable emission standard or standard of performance under" the Act. As if to make the point even more clear, the definition of BACT itself in section 169 applies to each such pollutant. ***The statutory language leaves no room for limiting the phrase "each pollutant subject to regulation"*** . . .

In sum, there is simply no basis in law for EPA to refuse to include a CO2 BACT emissions limit in the Bonanza PSD Permit.

II. EPA'S DECISION IS ARBITRARY AND CAPRICIOUS BECAUSE IT FAILS TO TAKE INTO ACCOUNT CONTRARY POSITIONS IT IS TAKING IN ANOTHER CASE.

The Bonanza PSD Permit should also be remanded because in it, EPA has taken positions contrary to those it has recently taken in another coal-fired power plant permitting matter. On June 22, 2007, in fulfillment of its responsibility under § 309 of the Clean Air Act to review and comment on major federal agency actions, EPA submitted comments on a Draft Environmental Impact Statement for Nevada's White Pine Energy Station Project.[3]

[3] This issue is also properly before the EAB; see *In re Encogen Cogeneration Facility*, 8 E.A.D. 244, 250 n.8 (EAB 1999) ("a petitioner may demonstrate that an issue was not reasonably ascertainable during the public comment period.")

Section 165(a)(2) directs the permitting authority to fully consider all written and oral presentations "on the air quality impact of such source, alternatives thereto, control technology requirements and other considerations." (Emphasis added.) The PSD program is designed "to assure that any decision to permit increased air pollution in any area to which this section applies is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decisionmaking process." CAA § 160(5).

In EPA's White Pine DEIS Comments the agency made specific findings that are directly relevant to the Bonanza project, and has erred here by failing to take account of its own findings in considering "alternatives" to the Bonanza project. For example, in its White Pine Comments EPA expressed concern that the "density of new coal-burning plants in Nevada is in excess of the demonstrated need for energy throughout the Western States." EPA Letter p. 2. EPA also found that BLM had erred in failing to consider alternatives to the proposed project such as energy efficiency, staged development, design for future carbon capture and storage, the potential for development of geothermal resources, and various other options. EPA Letter pp. 3-5, 14.

EPA must follow its own recommendations and findings in considering "alternatives" to Bonanza and assuring that all of the consequences of the permitting decision are thoroughly considered and fully informed. By failing to explain why energy efficiency, design for carbon capture and storage, and the potential for renewables are relevant in evaluating a proposed coal plant in Nevada but not in Utah, EPA's decisions in this proceeding are arbitrary and capricious. *See Kent County v. EPA*, 963 F.2d 391, 396 (D.C. Cir. 1992)(EPA decision to list a site on the National Priorities List was arbitrary and capricious because it failed to include in the administrative record relevant statements by agency experts.)

Lastly, in the event that EPA tries to justify its failure to impose a BACT emissions limit for CO2 in the Bonanza PSD permit on the grounds that there is no appropriate CO2 emissions technology, it is important to note that in its White Pine Comments EPA directed the BLM to "discuss carbon capture and sequestration and other means of capturing and storing carbon dioxide as a component of the proposed alternatives." Thus, EPA has elsewhere determined that CCS is an available technology that should be considered for the control of carbon dioxide emissions.

CONCLUSION

For the foregoing reasons the Board should review and remand the Bonanza PSD Permit to EPA.

Dated: October 1, 2007

Respectfully submitted,

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Exhibit 1

United States Environmental Protection Agency
Region 8
Air and Radiation Program
1595 Wynkoop Street
Denver, Colorado 80202-1129
August 30, 2007

Final
Air Pollution Control
Prevention of Significant Deterioration (PSD)
Permit to Construct

PSD-OU-0002-04.00

Permittee:
Deseret Power Electric Cooperative
10714 South Jordan Gateway
South Jordan, Utah 84095

Permitted Facility:
110-Megawatt Waste Coal Fired Unit
at Bonanza Power Plant
Uintah County, Utah

Table of Contents

I. Introduction

This Federal PSD permit is being issued under authority of 40 CFR 52.21. Deseret Power Electric Cooperative (hereinafter the "Permittee") proposes to construct a new 110-megawatt waste-coal-fired steam electrical generating unit ("WCFU") at the Permittee's existing Bonanza power plant near Bonanza, Utah, on the Uintah & Ouray Indian Reservation. Steam for the new unit will be supplied by a Circulating Fluidized Bed (CFB) boiler, with a maximum heat input capacity not to exceed 1,445 million Btu per hour (MMBtu/hr), and designed to combust waste coal from the Permittee's existing Deserado mine. The waste coal is generated from the coal washing process at the mine. Washed coal is supplied to the existing Bonanza Unit 1. Waste coal, which is presently landfilled in refuse pits at the Deserado mine will be reclaimed and/or diverted from the landfill for use in the new unit.

Proposed emission control equipment for the WCFU will consist of a baghouse for particulate control, a combination of limestone injection into the combustion zone and a dry scrubber downstream of the CFB boiler for control of sulfur oxides, sulfuric acid and condensible particulate matter, and Selective Non-Catalytic Reduction (SNCR) for control of nitrogen oxides. Dust from coal and limestone handling will be controlled by use of enclosed conveyors and by venting of dust to fabric filter dust collectors at conveyor transfer points. Dust from the coal and limestone stockpiles will be controlled by compaction and by spraying of surfactant sealant and/or water, where required by this permit. Dust from ash handling will be controlled by venting of dust to fabric filter dust collectors and by hydrating the ash prior to transfer for disposal.

Potential controlled emissions from the WCFU are estimated as the following:

Pollutant	Estimate	Basis of emission estimate
Particulate matter at CFB boiler stack	190 tons/yr	0.03 lb/MMBtu allowable emission rate, including condensible particulate
Particulate matter from coal, ash and limestone handling	18 tons/yr	AP-42 emission factors for coal, ash and limestone handling; emission limits in this permit for baghouses
Sulfur Dioxide	348 tons/yr	0.055 lb/MMBtu allowable emission rate
Nitrogen Oxide	557 tons/yr	0.088 lb/MMBtu allowable emission rate
Carbon Monoxide	949 tons/yr	0.15 lb/MMBtu allowable emission rate
Sulfuric acid	22 tons/yr	0.0035 lb/MMBtu allowable emission rate
Volatile Organic Compounds	32 tons/yr	0.005 lb/MMBtu emission rate by boiler design

The existing Bonanza power plant consists of a single bituminous coal-fired unit, rated at approximately 500 megawatts electrical output. It was constructed in the early 1980's and is operating under a Federal PSD permit originally issued on February 4, 1981, then updated and reissued on February 7, 2001. The existing power plant is a "major stationary source" as defined in Federal PSD rules at 40 CFR 52.21(b)(1)(i). The EPA has determined that the addition of the WCFU will constitute a "major modification" as defined in §52.21(b)(2)(i), and will therefore require a PSD permit. The WCFU is expected to result in significant emission increases of particulate matter, sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO) and sulfuric acid (H_2SO_4) from the power plant. Application of Best Available Control Technology (BACT) is required for these pollutants under §52.21(j)(3).

The initial PSD permit application for the WCFU was submitted on April 14, 2004. The application was revised and resubmitted on November 1, 2004. A modeling protocol was initially submitted on August 14, 2001, then revised and resubmitted on March 9, 2004. The permit application included an air quality modeling analysis, additional impacts analysis (regional haze, plume blight and deposition) and visibility analysis for Federal Class I areas under 40 CFR 52.21(k), (l), (m), (o) and (p), as well as proposed emission limits for the WCFU. Emissions from existing Bonanza Unit 1 were included in the modeling analysis. No violations of PSD Class I or Class II ambient air increments, or of National Ambient Air Quality Standards, were predicted.

Subsequent discussions between the Permittee and EPA led to further revisions to the permit application, principally:

- a proposal for a dry scrubber for additional SO_2 control,
- a proposal for lower BACT emission limits than originally proposed for particulate matter, SO_2 and NO_x,
- a proposal for alternative BACT emission restrictions applicable during boiler startup and shutdown events,
- a proposal for BACT emission limits for the materials handling baghouses and cooling tower,
- a revised proposal for BACT emission limits for the emergency generator,
- a top-down BACT analysis for control of condensible particulate matter, and
- a request for operational flexibility to blend run-of-mine with the waste coal at any time, if needed, at up to a 50/50 ratio by weight, equivalent to approximately 6,500 Btu/lb coal.

Correspondence between the Permittee and EPA pertaining to these application revisions and other topics is included in the Administrative Record for issuance of this permit. A chronology and description of that correspondence is included in the Statement of Basis for issuance of this permit.

II. Findings

On the basis of the information in the administrative record, EPA has determined that:

A. The Permittee will meet all of the applicable requirements of the PSD regulations (40 CFR 52.21);

B. No applicable emission standard, PSD increment, or national ambient air quality standard will be violated by the emissions from the permitted facility; and

C. The Permittee can comply with the conditions of this permit.

In issuing this permit EPA does not assume any risk of loss which may occur as a result of the operation of the permitted facility by the Permittee, if the conditions of this permit are not met by the Permittee.

III. Conditional Permit to Construct

A. General Information

Permit number:	PSD-OU-0002-04.00
AFS number:	049-047-00001
SIC Code and SIC Description:	4911 – Electric services

Site Location	Corporate Office Location
Bonanza Power Plant	Deseret Power Electric Cooperative
12500 East 25500 South	10714 South Jordan Gateway
Vernal, Utah 84078	South Jordan, Utah 84095

The equipment listed in this permit shall be constructed by Deseret Power at the following location:

Bonanza Power Plant
Latitude 40° 05' 11" N, Longitude 109° 16' 48" W
35 miles southeast of Vernal, Utah

B. Process Description: The Waste Coal Fired Unit (WCFU) will consist of a circulating fluidized bed (CFB) boiler and associated equipment at the existing Bonanza power plant. The WCFU will have a nominal capacity of up to 110 megawatts gross electrical output. The CFB boiler will supply superheated steam to the extracting/condensing turbine, to drive an electrical generator and supply cycle and plant auxiliary steam through uncontrolled extraction from the turbine.

The CFB boiler will be fired on western bituminous coal from the Deserado mine. Deseret Power has designed the project to be fired on waste coal alone, but has also requested operational flexibility in the permit to use a blend of waste coal and run-of-mine coal at any time, as needed, at up to a 50/50 ratio by weight (equivalent to coal with heat content of approximately 6,500 Btu/lb). Run-of-mine coal is raw coal from the mine that has not been washed in the coal washing plant at the mine. During emergencies that would prevent the waste coal from being delivered and placed into the WCFU, Deseret Power has requested permit flexibility to use either run-of-mine coal or washed coal from the Deserado mine.

The waste coal is produced as an unavoidable byproduct of the coal washing process at the Deserado mine. The waste coal has a nominal heating value range of approximately 3,000 to 5,400 Btu/lb, with an average heating value of approximately 4,000 Btu/lb. The waste coal will be delivered via an existing electric train line from the Deserado mine, approximately 35 miles east of the Bonanza power plant. The run-of-mine coal has a heating value ranging from 8,500 to 10,000 Btu/lb.

Emission controls for the CFB boiler shall consist of:

- a pulse-jet fabric filter baghouse for particulate control,
- limestone injection into the CFB combustion zone, along with a dry scrubber downstream for SO_2 and H_2SO_4 control,
- Selective Non-Catalytic Reduction (SNCR) for NO_x control, and
- proper combustion practices for CO control.

Emission controls for particulate emissions from coal, limestone and ash handling shall consist of enclosed conveyors and venting of dust to fabric filter dust collectors at conveyor transfer points. This permit includes BACT emission limits for the CFB boiler and for the fabric filter dust collectors at the materials handling system, as required by 40 CFR 52.21(j)(3).

An emergency generator will also be installed, with potential emissions below 1 ton/yr for all pollutants, based on maximum expected operation of 100 hours per year. This permit includes BACT emission limits for the emergency generator, as required by §52.21(j)(3).

Emission controls for fugitive particulate emissions from coal, limestone and ash/sludge stockpiles shall consist of compaction and periodic spraying of surfactant sealant. This permit includes operational requirements as BACT for fugitive emission control.

The WCFU will utilize portions of the existing Bonanza power plant facilities, including: control room, administration building, raw water supply system, fuel oil system, plant drains, storm drains, sanitary and corrosive drain systems, ash conveyors, delivery of waste coal via existing electric train from the Deserado mine, coal rail car receiving hopper and transfer building, demineralized water system, fire protection/ service water, potable water, auxiliary steam, grounding and cathodic protection systems.

C. Approved Installation

The approved WCFU installation shall consist of the following equipment:

One circulating fluidized bed boiler, maximum heat input capacity not to exceed 1,445 MMBtu/hr, designed for firing on waste coal.

Emission controls for CFB boiler: pulse-jet fabric filter baghouse, limestone injection system, dry SO_2 scrubber (spray dry absorber), Selective Non-Catalytic Reduction.

Emergency generator (diesel-fired internal combustion engine, not to exceed 750 kilowatt estimated capacity, equivalent to 1,005 estimated horsepower).

Coal handling system: enclosed coal conveyors, coal storage pile, coal bunkers, dust collection systems (baghouses and vent filters) at coal transfer points:

Emission Point ID	Estimated Air Flow	Location
Baghouse OCH/DC-1	15,000 dscfm	existing terminal building
Baghouse EP-W-MH-01	8,500 dscfm	crusher building
Baghouse EP-W-MH-02	8,500 dscfm	coal day silo headhouse

Limestone handling system: storage pile, reclaim hopper, limestone silo with dust collection system (baghouses and vent filter):

Emission Point ID	Estimated Air Flow	Location
Baghouse EP-W-MH-03	1,000 dscfm	Limestone crushers
Vent filter EP-W-MH-04	1,000 dscfm	Surge bin
Baghouse EP-W-MH-05	4,000 dscfm	Limestone storage silo

Ash handling system: ash hydration for dust control, ash transfer system to landfill, with dust collection system (baghouses and vent filters):

Emission Point ID	Estimated Air Flow	Location
Vent filter EP-W-MH-06	1,000 dscfm	Bed ash recirculation bin
Vent filter EP-W-MH-07	1,000 dscfm	Bed ash disposal surge bin
Baghouse EP-W-MH-08	3,600 dscfm	Fly ash silo
Baghouse EP-W-MH-09	3,600 dscfm	Bed ash silo

Lime material handling with dust collection (vent filter):

Emission Point ID	Estimated Air Flow	Location
Vent filter EP-W-MH-10	2,000 dscfm	Lime storage silo

Inert material handling with dust collection (vent filter):

Emission Point ID	Estimated Air Flow	Location
Vent filter EP-W-MH-11	2,000 dscfm	Inert bed day bin

Cooling tower with cellular-type mist eliminators

D. PSD BACT and Other Emission Limits

The term "30-day rolling average," as used in this permit, shall mean the average of 30 successive boiler operating days.

The term "boiler operating day," as used in this permit, shall have the meaning given in the revised 40 CFR 60 Subpart Da, published in the Federal Register on February 27, 2006 (71 FR 9866), as it applies to new units: *"Boiler operating day" ... means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted for the entire 24-hour period.*

1. CFB boiler

a. Particulate matter (PM): The Permittee shall not discharge or cause the discharge of total particulate matter (including condensible particulate matter) from the CFB boiler to the atmosphere in excess of 0.03 lb/MMBtu heat input, on a 24-hour block average (midnight to midnight), of which the filterable (non-condensible) portion shall not exceed 0.012 lb/MMBtu heat input on a 24-hour block average. The same emission limits shall apply for PM_{10}.

Because condensible particulate matter emissions from CFB boilers have not been widely quantified, there is a possibility that the actual condensible portion of particulate matter would cause the emission limit of 0.03 lb/MMBtu for total PM/PM_{10} to be exceeded. In the event the Permittee cannot meet that limit because of condensible particulate matter, EPA may adjust the emission limit to a level not to exceed 0.045 lb/MMBtu, pending EPA's review of stack test results at the CFB boiler.

b. Sulfur dioxide (SO_2): The Permittee shall not discharge or cause the discharge of SO_2 from the CFB boiler to the atmosphere in excess of the following:

(i) Prior to the date which is 12 months after completion of initial performance testing: 0.055 lb/MMBtu heat input, on a 30-day rolling average.

(ii) Beginning on the date which is 12 months after completion of initial performance testing, and thereafter:

(a) 0.055 lb/MMBtu heat input, on a 30-day rolling average, for any boiler operating day when the uncontrolled SO_2

emission potential of the combusted coal is 2.2 lb/MMBtu or greater, on a 30-day rolling average.

(b) a calculated emission limit, on a 30-day rolling average, as set forth below, for any boiler operating day when the uncontrolled SO_2 emission potential of the combusted coal is less than 2.2 lb/MMBtu, on a 30-day rolling average:

$$\frac{0.055A + 0.040B}{30} \quad \text{lb/MMBtu heat input}$$

Where:

A = Number of BOD, during 30 successive BODs prior to the calculation, when the uncontrolled SO_2 emission potential of the combusted coal was 1.9 lb/MMBtu or greater, on a 30-day rolling average

B = Number of BOD, during 30 successive BODs prior to the calculation, when the uncontrolled SO_2 emission potential of the combusted coal was less than 1.9 lb/MMBtu, on a 30-day rolling average

BOD = Boiler Operating Day

For purposes of determining the applicable SO_2 emission limit in either *(a)* or *(b)* above, the uncontrolled SO_2 emission potential of the coal, on a 30-day rolling average, shall be based on coal samples obtained during a period of 30 successive BODs which ends five BODs prior to the day on which the emission limit applies.

c. Nitrogen oxides (NO_x): The Permittee shall not discharge or cause the discharge of NO_x from the CFB boiler to the atmosphere in excess of the following:

(i) Prior to the date which is 12 months after completion of initial performance testing: 0.088 lb/MMBtu heat input, on a 30-day rolling average.

(ii) Beginning on the date which is 12 months after completion of initial performance testing, and thereafter: 0.080 lb/MMBtu heat input, on a 30-day rolling average.

d. Carbon monoxide (CO): The Permittee shall not discharge or cause the discharge of CO from the CFB boiler to the atmosphere in excess of 0.15 lb/MMBtu heat input, on a 30-day rolling average.

e. Sulfuric acid (H_2SO_4): The Permittee shall not discharge or cause the discharge of sulfuric acid from the CFB boiler to the atmosphere in excess of 0.0035 lb/MMBtu heat input, average of three EPA Method 8 or NCASI Method 8A test runs.

2. Emergency generator: The Permittee shall only use an Emergency Generator engine that is certified by the engine manufacturer, via "certification of conformity" from EPA as defined in 40 CFR part 89, to be compliant with the following engine emission standards, for non-road compression-ignition engines with rated power more than 560 kilowatts, as codified at 40 CFR 89.112, Table 1:

a. For NO_x plus nonmethane hydrocarbons, the "Tier 2" emission standard of 6.4 grams per kilowatt-hour.

b. For CO, the "Tier 2" emission standard of 3.5 grams per kilowatt-hour.

c. For particulate matter, the "Tier 2" emission standard of 0.20 grams per kilowatt-hour.

3. Materials handling system. The Permittee shall not discharge, or cause the discharge, of particulate matter from the materials handling system baghouses or vent filters in excess 10 percent opacity on a six-minute average[1], nor at the baghouses in excess of the following emission limits, in grains per dry standard cubic foot (gr/dscf), average of three EPA Method 5 or 5D test runs:

Emission Point	Location	Emission Limit
OCH/DC-1	Existing terminal building	0.005 gr/dscf
EP-W-MH-01	Crusher building	0.005 gr/dscf
EP-W-MH-02	Coal day silo headhouse	0.005 gr/dscf
EP-W-MH-03	Limestone crushers	0.01 gr/dscf
EP-W-MH-05	Limestone storage silo	0.01 gr/dscf
EP-W-MH-08	Fly ash silo	0.01 gr/dscf
EP-W-MH-09	Bed ash silo	0.01 gr/dscf

[1] The ten percent visible opacity limit is included for the purpose of monitoring performance of the material handling baghouses but is not a BACT requirement.

4. Cooling tower: For purposes of limiting emissions of particulate matter, the cooling tower shall be equipped with cellular-type mist eliminators designed to limit circulating water drift loss to no more than 0.001 percent.

E. PSD BACT Operating Requirements and Fuel Restrictions

1. General requirements. At all times, including periods of startup, shutdown, and malfunction, all equipment, facilities and air pollution control systems installed or used to achieve compliance with this permit shall be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Air pollution control systems subject to this permit condition shall include the following:

   a. CFB boiler: Pulse-jet fabric filter baghouse for control of particulate emissions, limestone injection system and dry SO_2 scrubber for control of sulfur dioxide, sulfuric acid and condensible particulate emissions, and a Selective Non-Catalytic Reduction system for control of nitrogen oxide emissions.

   b. Coal, ash and limestone handling: Baghouses and vent filters as listed in condition III.C of this permit, and emission control equipment and techniques as listed in condition III.F of this permit, for control of particulate emissions.

2. Fuel restrictions at CFB boiler.

   a. Fuel during startup. The Permittee shall not combust, in the CFB boiler, any startup fuel other than diesel fuel (#2 grade fuel oil or better) or natural gas. The diesel fuel shall have a sulfur content of no more than 0.05 percent (500 parts per million) by weight.

   b. Fuel during emergencies when waste coal is not available. During any emergency that prevents waste coal from being delivered from the Deserado mine and placed into the WCFU, the Permittee is permitted to combust, in the CFB boiler, any other coal originating from the Deserado mine, including run-of-mine coal or washed coal.

      For purposes of this permit condition, an emergency shall mean any situation arising from sudden and reasonably unforeseeable events beyond the control of the Permittee. Depletion of the waste coal stockpile at the Deserado mine is not an emergency. Run-of-mine coal shall mean raw mined coal that has not been processed through the coal washing plant at the Deserado mine. Washed coal shall mean coal that has been processed through the wash plant.

c. Fuel other than during startup or emergencies. Other than during startup or emergencies specified in conditions 3.a and 3.b above, the Permittee is permitted to combust, in the CFB boiler, coal from the Deserado mine consisting of either waste coal alone, or else a blend of waste coal and run-of-mine coal in any ratio yielding up to 6,500 Btu/lb heat content on a 30-day rolling average.

3. Requirements at emergency generator

a. The Permittee shall not combust, in the emergency generator, any fuel other than diesel fuel (#2 grade fuel oil or better). The diesel fuel shall have a sulfur content of no more than 0.05 percent (500 parts per million) by weight.

b. The emergency generator shall be installed, maintained and operated in accordance with the engine manufacturer's instructions and recommendaions for ensuring compliance with the "Tier 2" emission standards listed in 40 CFR 89.112, Table 1, and as PSD BACT limits in condition III.D.2 of this permit.

c. The Permittee shall only use the emergency generator:

(i) when routine electrical power to the permitted facility is unavoidably interrupted, and

(ii) for maintenance checks and readiness testing on the generator engine.

Usage shall not exceed 100 hours per 12-month period. Usage for maintenance checks and readiness testing may be excluded from the calculation of 12-month usage, provided that the checks and testing are recommended by the manufacturer, the vendor, or the insurance company associated with the engine.

F. PSD BACT Fugitive Emission Control Requirements

1. All coal, limestone and ash conveyors serving the WCFU shall be fully enclosed.

2. All fugitive emissions generated at coal, limestone and ash conveyor transfer points serving the WCFU, as well as at coal, limestone, ash, lime and inert material storage silos and storage bins serving the WCFU, shall be routed to fabric

filter dust collectors (baghouses or vent filters).

3. All fugitive emissions from unenclosed coal and limestone stockpiles serving the WCFU shall be controlled by compaction of the surface and by application of water sprays and surfactant when warranted. Conditions which warrant application of surfactant or water sprays are defined in this permit as any time a ten percent opacity level is exceeded.

   The Permittee shall conduct weekly Method 22 observations of the coal and limestone stockpiles for visible emissions. If any visible emissions are observed, the Permittee shall conduct a Method 9 visible emission observation within 24 hours, by an observer who is certified in the use of Method 9. If opacity in excess of ten percent is observed by Method 9, the Permittee shall immediately apply dust suppression (water spray and/or surfactant).

4. The coal stockpile loadout shall be equipped with a telescoping chute to enclose the free fall of material during loadout operation and limit the exposure of the material flow stream to the wind.

5. All ash generated by the CFB boiler shall be hydrated, via a pugmill mixer, prior to transfer for disposal.

G. <u>Modeling Limits</u>: The Permittee shall not discharge or cause the discharge of emissions from the CFB boiler to the atmosphere in excess of the following rates used in modeling ambient impacts of the WCFU:

1. 872 pounds per hour of sulfur dioxide, averaged over a 3-hour block period.

2. 202 pounds per hour of sulfur dioxide, averaged over a 24-hour block period.

3. 75.4 pounds per hour of total PM_{10} (filterable plus condensible), averaged over a 24-hour block period.

H. <u>Initial Performance Tests:</u>

1. <u>General requirement</u>. Initial performance tests are required for demonstrating compliance with all PSD BACT emission limits and modeling limits listed in this permit, except as follows:

   a. <u>Exception for emergency generator</u>. Compliance with the operating restrictions and other requirements in conditions III.D.2 and III.E 3 of this permit shall serve as demonstration of compliance with the PSD BACT emission limits in III.D.2.

b. <u>Exception for materials handling baghouses</u>. Initial performance stack tests shall be required only at baghouses OCH/DC-1, EP-W-MH-01 and EP-W-MH-05, but with the following conditions:

If results of the initial performance stack test at EP-W-MH-01 are in excess of the applicable emission limit in this permit, then baghouse EP-W-MH-02 shall also be initially stack tested, within 90 calendar days after initial performance stack test results at EP-W-MH-01 are required under this permit to be submitted to EPA.

If results of the initial performance stack test at EP-W-MH-05 are in excess of the applicable emission limit in this permit, then baghouses EP-W-MH-03, EP-W-MH-08 and EP-W-MH-09 shall also be initially stack tested, within 90 calendar days after initial performance stack test results at EP-W-MH-05 are required under this permit to be submitted to EPA.

2. <u>Test deadlines.</u>

a. <u>CFB boiler</u>. Initial performance testing shall be completed within 60 calendar days after achieving the maximum heat input rate at which the CFB boiler will be operated, but not later than 180 calendar days after the date of initial startup of the boiler, unless a longer timeframe is requested by the Permittee and agreed to by EPA.

b. <u>Materials handling baghouses</u>. Initial performance stack testing at baghouses OCH/DC-1, EP-W-MH-01 and EP-W-MH-05 shall be completed within 60 calendar days after initial startup of each baghouse.

The deadline for submittal of test reports may be found in condition III.L.1.

3. <u>Test protocol</u>. Within 90 calendar days after the date of initial startup of the CFB boiler, and at least 30 calendar days prior to initial performance testing, the Permittee shall submit a test protocol to EPA for all initial performance tests that are required to be conducted under this permit. The test protocol shall outline the proposed test methodologies and procedures to be used. Performance tests shall be conducted in accordance with the test protocol and the test methods specified in this permit, and any changes required by EPA.

4. <u>Test notification</u>: The Permittee shall submit written notification to EPA of the anticipated date of initial performance tests, no less than 30 days prior to commencement of each such test, to provide EPA an opportunity to have an observer present. EPA shall also be notified promptly of any change in the

anticipated date.

5. Representative conditions for testing. Initial performance tests shall be conducted under representative conditions, defined as follows:

   a. CFB boiler. "Representative conditions" shall mean coal is being fed to the boiler during the test which is representative of "average" coal quality in terms of sulfur content (0.34% $\pm$ 0.10%) and heat content (4,000 Btu/lb $\pm$ 500 Btu/lb), and the boiler is operating at no less than 90% of the installed boiler maximum heat input capacity.

   b. Materials handling baghouses. "Representative conditions" shall mean the materials throughput is at no less than 90% of the maximum design throughput, at the materials transfer location where the emissions are controlled by that baghouse, and volumetric flow rate through the baghouse is at no less than 90% of the installed baghouse design flow rate.

6. Test methods:

   a. Particulate matter: For measurement of total filterable particulate matter at the CFB boiler exhaust stack, a particulate matter continuous emission monitoring system (PM CEMS) shall be used. 40 CFR 60, Appendix A, Method 5 or 5D test shall be conducted, in conjunction with 40 CFR 60, Appendix B, Performance Specification 11, to verify CEMS accuracy.

      For measurement of condensible particulate matter at the CFB boiler exhaust stack, 40 CFR 51, Appendix M, Method 202 shall be used. In lieu of Method 202, the Permittee shall be allowed to use Conditional Test Method (CTM) 039. CTM-039 may be found on EPA website at: http://www.epa.gov/ttn/emc/ctm/ctm-039.pdf.

      All particulate matter measured at the CFB boiler exhaust stack (including condensible particulate matter) shall be considered PM_{10}. Separate testing for PM_{10} via Methods 201 or 201A shall not be required unless requested by EPA.

      For measurement of particulate matter at the exhaust stacks of the materials handling system baghouses, Method 5 or 5D shall be used.

   b. Sulfur dioxide (SO_2): For measurement of SO_2 at the CFB boiler exhaust stack, a continuous emission monitoring system (CEMS) shall be used. 40 CFR 60, Appendix A, Method 6, 6A, 6B or 6C test shall be conducted, in conjunction with 40 CFR 60, Appendix B, Performance Specification 2, to verify CEMS accuracy.

c. Nitrogen oxides (NO_x): For measurement of NO_x at the CFB boiler exhaust stack, a continuous emission monitoring system (CEMS) shall be used. 40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D or 7E test shall be conducted, in conjunction with 40 CFR 60, Appendix B, Performance Specification 2, to verify CEMS accuracy.

d. Carbon monoxide (CO): For measurement of CO at the CFB boiler exhaust stack, a continuous emission monitoring system (CEMS) shall be used. 40 CFR 60, Appendix A, Method 10 test shall be conducted, in conjunction with 40 CFR 60, Appendix B, Performance Specification 4, 4A or 4B, to verify CEMS accuracy.

e. Diluent (CO_2 or O_2): For measurement of diluent at the CFB boiler exhaust stack, a continuous monitoring system shall be used. 40 CFR 60, Appendix A, Method 3A or 3C test shall be conducted, in conjunction with 40 CFR 60, Appendix B, Performance Specification 3, to verify accuracy of the diluent Continuous Monitoring System.

For purposes of demonstrating continuous SO_2, NO_x and CO emission compliance under this permit for any period of operation with use of CEMS data, as well as for total filterable particulate matter with use of PM CEMS data, the Permittee may adjust to five percent any measured carbon dioxide (CO_2) diluent values that are below five percent, and may adjust to fourteen percent any measured oxygen (O_2) diluent values that are above fourteen percent, as currently allowed at Acid Rain Units by 40 CFR 72.2 (definition of "diluent cap value"), 40 CFR 75 Appendix A, section 2.1.2.1(b), and 40 CFR 75 Appendix F, section 3.3.4.

f. Sulfuric acid (H_2SO_4): For measurement of H_2SO_4 at the CFB boiler exhaust stack, 40 CFR 60, Appendix A, Method 8 shall be used. In lieu of Method 8, the Permittee shall be allowed to use NCASI Method 8A, published by the National Council for Air and Stream Improvement, Inc. (NCASI), December 1996, available at: http://www.ncasi.org.

g. Sulfur content of coal: ASTM Method D4239, most recent version designated "active" on ASTM website, shall be used.

h. Heat content (gross calorific or Btu content) of coal: ASTM Method D5865, most recent version designated "active" on ASTM website,shall be used.

i. Sulfur content of diesel fuel: ASTM Method D-4294, most recent version designated "active" on ASTM website,shall be used. Records from the fuel supplier, verifying that sulfur content of the diesel fuel is no greater than 0.05%, shall be based on ASTM testing.

j. Visible emissions: 40 CFR 60, Appendix A, Method 9 or 22 shall be used. Situations requiring the use of Method 9 are specified in condition III.I.6.b of this permit.

I. Compliance Provisions

1. PSD BACT emission limits and modeling limits apply at all times. The PSD BACT emission limits in this permit, as well as the modeling limits, apply at all times, including periods of startup, shutdown and malfunction.

2. NSPS exemptions not applicable to emission limits in this permit. The following exemption language in 40 CFR part 60 is not applicable to emission limits in this permit:

a. 40 CFR 60, subpart Da, at §60.48Da(c), §60.48Da(g)(1) and §60.48Da(g)(3), "Compliance provisions," regarding exemptions from emission standards during periods of startup, shutdown, malfunction and emergency conditions.

b. 40 CFR 60, subpart A, at §60.8(c), "Performance tests," regarding exemptions from violation status for excess emissions during periods of startup, shutdown and malfunction.

c. 40 CFR 60, subpart A, at §60.11(c), regarding exemption from opacity standards during periods of startup, shutdown and malfunction.

3. NSPS Subpart A excess emission reporting and recordkeeping requirements not applicable to emission limits in this permit. Language in 40 CFR 60.7, regarding excess emission reporting and recordkeeping, shall not apply to the PSD BACT emission limits or modeling limits in this permit.

4. Continuous compliance demonstrations.

a. During and after initial performance testing, compliance with the PSD BACT emission limit for total filterable particulate matter at the CFB boiler exhaust stack shall be demonstrated on a continuous basis using a Particulate Matter Continuous Emission Monitoring System (PM CEMS).

b. During and after initial performance testing, compliance with the PSD BACT emission limit for total particulate matter (including condensible particulate matter) at the CFB boiler exhaust stack shall be demonstrated on a continuous basis by adding PM CEMS measurements to the results of the most recent stack test for condensible particulate matter. The first stack test for condensible particulate matter shall be conducted as part of initial performance testing required under this permit for total particulate matter. Subsequent tests shall be no less frequent than annually.

"Annually" shall mean each test must be conducted no later than the end of the fourth quarter after the quarter in which the previous test was conducted.

c. During and after initial performance testing, compliance with the PSD BACT emission limits for SO_2, NO_x and CO at the CFB boiler shall be demonstrated on a continuous basis using SO_2, NO_x and CO CEMS.

d. Emissions of SO_2, NO_x and CO at the CFB boiler shall be calculated on a 30-day rolling average basis. At the end of each boiler operating day, a new 30-day rolling average emission rate in lb/MMBtu is calculated from the arithmetic average of all valid hourly emission rates for 30 successive boiler operating days, based on continuous emission monitoring system data and fuel heat input.

Emissions of total particulate matter and total filterable particulate matter shall be calculated on a 24-hour block average basis (midnight to midnight). At the end of each boiler operating day, a new 24-hour average emission rate in lb/MMBtu is calculated from the arithmetic average of all valid hourly emission rates for that day, based on PM CEMS data, fuel heat input, and for total particulate matter, the results of the most recent annual stack test for the condensible portion.

The term "boiler operating day" shall have the meaning given at the beginning of condition III.D of this permit. The term "valid hourly emission rate" shall have the meaning given in 40 CFR 75.10(d)(1):

Hourly averages shall be computed using at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour), if data are unavailable as a result of the performance of calibration, quality assurance, or preventive maintenance activities *pursuant to 40 CFR 75.21 and 40 CFR 75 Appendix B, or backups of data from the data acquisition and handling system, or recertification pursuant to 40 CFR 75.20. The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour.*

5. Compliance demonstrations by annual stack test. Compliance with the PSD BACT emission limit for sulfuric acid at the CFB boiler, in condition III.D.1.e of this permit, shall be demonstrated by annual stack tests, using the applicable test method specified in this permit. "Annual" shall mean each test must be conducted no later than the end of the fourth quarter after the quarter in which the previous test was conducted.

   Stack tests for condensible particulate matter at the CFB boiler shall be annual, as specified in condition III.I.4.b of this permit, as part of demonstration of compliance with the PSD BACT emission limit for total particulate matter.

   For the materials handling system baghouses, if results of any initial performance stack test required under condition III.H.1.b of this permit are in excess of the applicable emission limit for that baghouse, the baghouse shall be retested annually. If results of a retest are not in excess of the applicable emission limit, further retests shall not be required.

   Stack tests shall be conducted under "representative conditions" as defined in condition III.H.5 of this permit. Test results shall be expressed as the arithmetic average of three separate test runs. Test results shall be submitted to EPA within 60 calendar days after testing. The first test shall be conducted as part of the initial performance testing required under this permit.

6. Compliance demonstrations for opacity. For demonstrating compliance with the opacity limit of ten percent at the materials handling vent filters and baghouses in condition III.D.3 of this permit, the Permittee shall conduct Method 22 visible emission observations at least once per month, at each vent filter and baghouse. If any visible emissions are observed, both of the following actions shall be taken:

   a. The cause of the visible emissions shall be investigated and any baghouse or vent filter malfunction shall be corrected within three working days in the case of broken or damaged bags, or within seven working days for any other type of baghouse malfunction.

   b. A Method 9 visible emission observation shall be conducted and recorded for that baghouse or vent filter, by an observer who is certified in the use of Method 9, within 24 hours after visible emissions are observed by Method 22.

If no visible emissions are observed in three consecutive monthly observations, frequency of observation at that baghouse or vent filter may be reduced to quarterly. If visible emissions are observed in any quarterly observation, frequency of observation shall return to monthly.

7. Compliance demonstrations for emission limits in pounds per hour. The Permittee shall use the following procedures for demonstrating compliance with the modeling limits in condition III.G. of this permit:

   a. Sulfur dioxide (SO_2): The output from SO_2 CEMS, in parts per million by volume, shall be multiplied by the output from the continuous volumetric flow rate monitor in the CFB boiler exhaust stack, in actual cubic feet per second. The result shall be averaged over each 3-hour block period and 24-hour block period (midnight to midnight), and appropriate conversion factors shall be applied to yield a result in pounds per hour, on 3-hour block and 24-hour block averages.

   b. Total PM_{10} (filterable plus condensible):

      (i) Filterable portion: The output from the PM CEMS shall be multiplied by the output from the continuous volumetric flow rate monitor in the CFB boiler exhaust stack and the results averaged over each 24-hour block period (midnight to midnight), then appropriate conversion factors applied, to yield a result in pounds per hour on a 24-hour block average. All particulate measured shall be considered PM_{10}.

      (ii) Condensible portion: The results of the latest stack test for condensible particulate matter in pounds per hour shall be used.

      The results of (i) and (ii) above shall be added together to yield total PM_{10}.

For calculating pounds per hour of emissions under this permit condition, conversion of CEMS measurements into units of lb/MMBtu, and the diluent cap approach described in condition III.H.5.e of this permit, shall not apply.

8. Compliance demonstrations by recordkeeping.

   a. Fuel restrictions at CFB boiler. For demonstrating compliance with the fuel restrictions in condition III.E.3 of this permit, the Permittee shall keep the following records:

(i) Fuel during startup. Date of each startup and type(s) of fuel used for startup. Where fuel oil is used as startup fuel, records shall include certification from the fuel oil supplier that the sulfur content of the fuel oil is no greater than 0.05 percent.

(ii) Fuel during emergencies when waste coal is not available. Date, cause and duration of each emergency; type of fuel used (run-of-mine coal, washed coal, or any blend of these two fuels).

(iii) Fuel other than during startup and emergencies. The date and the heat content of the as-fired coal, for any days on which the 30-day rolling average heat content of the as-fired coal exceeds 6,500 Btu/lb. This recordkeeping requirement is in addition to any other requirement in this permit to keep records of coal heat content.

b. Emergency generator. For demonstrating compliance with the PSD BACT emission limits, operating requirements and fuel restrictions at the emergency generator engine in conditions III.D.2 and III.E.3 of this permit, the Permittee shall keep the following records:

(i) A copy of the engine manufacturer's "certification of conformity" from EPA, as defined in 40 CFR part 89, that the engine is compliant with the "Tier 2" emission standards in 40 CFR 89.112, Table 1, for engines with rated power more than 560 kilowatts. This record shall be maintained for the life of the engine.

(ii) A copy of the engine manufacturer's instructions and recommendations relating to operation and maintenance of the engine, for minimizing emissions in conformance with "Tier 2" emission standards in 40 CFR 89.112, Table 1, for engines with rated power more than 560 kilowatts. These records shall be maintained for the life of the engine.

(iii) Records of all maintenance performed on the engine. These records shall be created and maintained for each calendar day on which maintenance is performed.

(iv) Records of certification from the fuel oil supplier, for each fuel oil delivery, that the sulfur content of the fuel oil combusted in the engine, as determined by the applicable ASTM Method specified in this permit, is no greater than 0.05 percent.

(v) Records of the dates and hours of operation of the engine and the reason for each usage. Records of hours of engine usage shall include rolling 12-month totals. Records shall also be maintained of any periods of usage due to maintenance checks or readiness testing which are allowed by permit condition III.E.3.c. to be excluded from the calculation of rolling 12-month totals.

c. Fugitive dust control. For demonstrating compliance with the fugitive dust control requirements in condition III.F.3 of this permit, the Permittee shall keep records of all weekly Method 22 visible emission observations, as well as a copy of any Method 9 visible emission observation forms that were filled out, as well as records of any compaction and any application of surfactant sealant and water sprays, at the unenclosed coal and limestone stockpiles serving the WCFU. Records shall include the following information:

(i) Stockpile identification (coal/limestone/location)
(ii) Date of application/compaction
(iii) Weather conditions
(iv) Stockpile surface conditions (dry, crumbled, moist, etc.)

d. Cooling tower. For demonstrating compliance with the requirement in condition III.D.4 of this permit that mist eliminators at the WCFU cooling tower be designed to limit circulating water drift loss to 0.001 percent or less, the Permittee shall keep records from the manufacturer documenting this design feature.

J. Compliance Monitoring Requirements

1. Continuous Monitoring Systems

a. General requirement. The Permittee shall install, calibrate, maintain and operate continuous emission monitoring systems at the CFB boiler exhaust stack, and record the output of the systems, for measuring emissions of total filterable particulate matter, SO_2, NO_x and CO. The Permittee shall also install, calibrate, maintain and operate a diluent (CO_2 or O_2) continuous monitoring system, for measuring the oxygen or carbon dioxide content of the flue gases at the location where the SO_2 or NO_x emissions are monitored. Each continuous monitoring system shall comply with the requirements below.

b. Performance specifications and accuracy. Each continuous monitoring system shall comply with all applicable performance and quality assurance requirements at:

40 CFR 60, subpart A, at §60.13
40 CFR 60, subpart Da
40 CFR 60, Appendix B, Performance Specifications 2, 3, 4 and 11
40 CFR 60, Appendix F
40 CFR 75

Initial Performance Specification testing shall be conducted during the initial performance tests required under condition.III.H.1 of this permit.

c. Quality assurance project plan. Not less than 90 days prior to initial performance testing, the Permittee shall submit to EPA a quality assurance project plan for the certification and operation of each continuous monitoring system. The plan shall comply with 40 CFR 60, Appendix F and 40 CFR 75, Appendix B, and be consistent with requirements of condition III.J.1 of this permit. The plan shall be updated and resubmitted if requested by EPA.

d. Installation. Each continuous monitoring system shall be installed and operational prior to conducting the required initial performance tests. Verification of operational status shall, at a minimum, include completion *of the manufacturer's written requirements or recommendations for* installation, operation and calibration of the continuous monitoring systems. Notification of the operational status of each continuous monitoring system shall be provided to EPA within 30 days after the system becomes operational, or by the date on which initial performance testing is commenced, whichever occurs first.

e. Operation and availability. Except for unavoidable monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each continuous monitoring system shall be operated and data recorded during all periods of operation of the CFB boiler, including periods of startup, shutdown, malfunction, or emergency conditions as defined in 40 CFR 60, subpart Da. Each monitoring system shall meet minimum frequency of operation requirements as follows: the continuous monitoring system shall complete a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute period.

f. Data averaging. For continuous monitoring system measurements, one-hour arithmetic averages shall be computed as specified in condition

III.I.4.d of this permit. Thirty-day rolling average emission rates and 24-hour block average emission rates (for compliance with PSD BACT limits) shall be calculated as specified in condition III.I.4.d of this permit. Three-hour and 24-hour block average emission rates (for compliance with modeling limits) shall be calculated as specified in condition III.I.7 of this permit.

g. Calculation of emission rates in lb/MMBtu. The Permittee shall convert pollutant concentration data recorded by the SO_2, NO_x and CO CEMS, as well as data from the PM CEMS, into units of pounds per million Btu of heat input (lb/MMBtu), in accordance with F factors calculated from 40 CFR 60, Appendix A, Method 19, and using data from the diluent monitoring system. The Permittee may use the diluent cap approach described in condition III.H.5.e of this permit. Fuel sampling and analysis shall be conducted for determining F factors, using ASTM Methods specified in this permit.

2. Coal sulfur content and heat content monitoring: For determining the uncontrolled SO_2 emission potential of as-fired coal, and thereby determining the applicable SO_2 BACT emission limit under condition III.D.1.b.(ii) of this permit, the Permittee shall use the following procedure:

The as-fired coal shall be tested each boiler operating day for sulfur content and heat content. Each boiler operating day, the test results shall be used to calculate the uncontrolled SO_2 emission potential of the coal on a 30-day rolling basis, by summing the emission potential in lb/MMBtu for that day's coal with the emission potential in lb/MMBtu calculated for each of the previous 29 boiler operating days and dividing by 30.

K. Additional Recordkeeping Requirements. In addition to the records specified in condition III.I.8 of this permit, the Permittee shall keep all records specified below.

1. The Permittee shall keep a record of all initial performance tests and any subsequent stack tests required by this permit.

2. The Permittee shall keep a record of all information required in the continuous emission compliance reports described in condition III.L.2 of this permit. As stated in condition III.I.3 of this permit, the recordkeeping provisions of 40 CFR 60.7, pertaining to excess emissions measured by CEMS, shall not apply to the PSD emission limits or modeling limits in this permit.

3. The Permittee shall keep a record of all visible emission observations and corrective actions required by condition III.I.6 of this permit. For Method 22

visible emission observations, the records shall identify the baghouses and vent filters observed, the dates of the observations, and whether any visible emissions were detected. For Method 9 observations, the records shall include the Method 9 observation forms that were filled out. Records shall also include the dates and descriptions of any corrective actions required by condition III.I.6.

4. For each continuous monitoring system, the Permittee shall keep a record of the following: all emission measurements, all measurements and other data pertaining to monitoring system performance evaluations, all monitoring device or monitoring system calibration checks, all adjustments and maintenance performed on these systems or devices, and all other monitoring system information required by 40 CFR 60 Appendices B and F, and 40 CFR 75. The Permittee shall also keep a record of any instances where the diluent cap approach allowed by this permit was used.

5. The Permittee shall keep a record of any monitor inoperative periods, repairs or adjustments, for each continuous monitoring system.

6. The Permittee shall keep a record of all measurements of coal sulfur content and heat content required by this permit.

7. The Permittee shall keep a record of the manufacturer's recommended operation and maintenance procedures for all air pollution control equipment at the facility, as well as a record of any written standard operating procedures used at the facility that pertain to emission control or monitoring of emissions.

8. All records, reports, notifications, and support information (i.e. testing, monitoring, measurements, observations, maintenance activities, etc.) compiled in accordance with this permit shall be maintained by the Permittee as a permanent business record for at least five (5) years following the date of the record/report, shall be available for inspection by EPA, and shall be submitted to EPA upon request.

L. Reporting Requirements

1. Initial performance test reports. The Permittee shall submit a written report to EPA of the results of any initial performance test required by this permit within 60 days after completion of the test.

2. Continuous emission compliance reports.

a. Reports for demonstrating compliance with PSD BACT emission limits on 30-day rolling averages and 24-hour block averages. Within 30 days after the end of each quarter, the Permittee shall submit written reports to EPA of 30-day rolling average emissions in lb/MMBtu from the CFB boiler for the following pollutants:

- Sulfur dioxide
- Nitrogen oxide
- Carbon monoxide

Within 30 days after the end of each quarter, the Permittee shall submit written reports to EPA of 24-hour block average emissions in lb/MMBtu from the CFB boiler for the following pollutants:

- Total filterable particulate matter (PM CEMS data)
- Total particulate matter (filterable + condensible),

Each report shall identify the pollutant and applicable emission limit and shall include all of the following information for each 24-hour period:

(i) Calendar date.

(ii) For boiler operating days where the applicable SO_2 emission limit is required to be a calculated limit under condition III.D.1.b.(ii)*(b)* of this permit, identification of the emission limit applicable that day and the coal sulfur content and heat content values used by the Permittee for calculating that limit.

(iii) For SO_2, NO_x and CO, the average emission rate in lb/MMBtu for each 30 successive boiler operating days, ending with the last 30-day period in the quarter.

(iv) For total particulate matter and for total filterable particulate matter, the average emission rate in lb/MMBtu for each boiler operating day.

(v) Identification of any periods of non-compliance with the applicable PSD BACT emission limit, reasons for non-compliance, and description of corrective actions taken. Periods of boiler operation during startup, shutdown or malfunctions shall be included in the calculation of average emission rates. No periods of boiler operation may be excluded.

(vi) Identification of any boiler operating days for which pollutant or diluent data have not been obtained by an approved method under this permit, reasons for not obtaining the data, and description of corrective actions taken.

(vii) Identification of the "F" factor used for calculations, method of determination, type of fuel combusted, and identification of any periods for which the diluent cap approach allowed by this permit was used in calculating emissions in lb/MMBtu.

(viii) Identification of any times when hourly emission averages have been obtained based on manual sampling methods rather than continuous monitoring system data.

(ix) Identification of any times when the pollutant concentration exceeded full span of the continuous monitoring system.

(x) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with applicable Performance Specifications in 40 CFR 60 Appendix B.

b. <u>Reports for demonstrating compliance with modeling limits in pounds per hour</u>. Within 30 days after the end of each quarter, the Permittee shall submit written reports to EPA of emissions in pounds per hour at the CFB boiler for the following pollutants:

- Total PM_{10} (filterable + condensible), 24-hour block average
- Sulfur dioxide, 3-hour and 24-hour block average

Each report shall identify the pollutant, averaging time, and applicable emission limit and shall include all of the following information:

(i) Date(s) and duration of any emissions not in compliance with the applicable pounds-per hour emission limit in this permit. If no non-compliant emissions occurred during the quarter with regard to an applicable emission limitation, such information shall be stated in the report.

(ii) Magnitude of non-compliant emissions expressed in pounds per hour.

(iii) Reason(s) for the non-compliant emissions and corrective action taken.

(iv) Identification of any boiler operating days for which emissions data in pounds per hour have not been obtained by an approved method under this permit, reasons for not obtaining the data, and description of corrective actions taken.

(v) Identification of any times when emissions data in pounds per hour have been obtained based on manual sampling methods rather than continuous monitoring system data.

(vi) Identification of any times when the pollutant concentration exceeded full span of the continuous monitoring system.

The continuous emission compliance reporting requirements in condition III.L.2 of this permit shall not constitute a waiver of any emission reporting requirements in 40 CFR 60, 75 or 77, nor shall compliance with condition III.L.2 excuse or otherwise constitute a defense to any violation of this permit, or of any applicable law or regulation, that may be caused by the emissions.

3. Continuous monitoring system performance reports. Within 30 days after the end of each quarter, the Permittee shall submit written reports to EPA of the performance of the continuous monitoring systems at the CFB boiler for emissions of total filterable particulate matter, SO_2, NO_x, CO and for diluent (CO_2 or O_2). The report for each monitoring system shall contain the following information:

a. Baseline monitor information: pollutant, monitor manufacturer and model number, date of latest monitor certification or audit;

b. Date(s) and duration of each period during which the monitoring system was inoperative, except for zero and span adjustments and calibration checks;

c. For each period during which the monitoring system was inoperative, reason(s) it was inoperative;

d. Date(s) and duration of each period during which the monitoring system was "out-of-control," as defined in 40 CFR 60, Appendix F, section 5.2.

e. For each period during which the monitoring system was out-of-control, reason(s) it was out of control;

f. Total duration of monitor inoperative and out-of-control periods for the quarter, as a percentage of total boiler operating time for the quarter;

g. For monitor inoperative or out-of-control periods caused by equipment malfunctions, steps and procedures taken to prevent reoccurrence of the malfunctions;

h. Any monitoring system repairs or adjustments, regardless of whether the repairs or adjustments were made to correct an equipment malfunction;

i. Date(s) and results of any Relative Accuracy Test Audits, Cylinder Gas Audits, or Relative Accuracy Audits conducted during the quarter to comply with 40 CFR 60, Appendix F; and

j. If a monitoring system has not been inoperative, repaired or adjusted during the quarter, such information shall be stated in the report for that monitoring system.

The monitoring system performance reporting requirements in this permit shall not constitute a waiver of any monitoring system performance reporting requirements in 40 CFR 60 or 75.

4. Stack test reports. Within 60 calendar days after the stack test is conducted, the Permittee shall submit to EPA a written report of any stack test required by this permit. Each report shall include the following information:

a. Date of test

b. Emitting unit tested

c. Pollutant measured

d. Applicable emission limit

e. Information regarding representative conditions during testing, as follows:

For any stack tests at the CFB boiler:
(i) installed boiler maximum heat input capacity,
(ii) average heat input during the test, as a percent of capacity, and
(iii) average sulfur content and average heat content of coal being fired in the boiler during the test.

For any stack tests at the materials handling baghouses:

(i) installed baghouse design flow rate,

(ii) average flow rate during the test, as a percent of the design flow rate,

(iii) maximum design throughput, at the materials transfer location where the emissions are controlled by that baghouse, and

(iv) actual throughput rate at the materials transfer location, during the test, as a percent of maximum design throughput.

f. Emission measurement results from each test run, expressed in units of the applicable emission limit

g. Sampling and analysis procedures:

(i) Sampling locations

(ii) Test methods used

(iii) Analysis procedures and laboratory identification

h. Quality assurance procedures:

(i) Calibration procedures and frequency

(ii) Sample recovery and field documentation

(iii) Chain-of-custody procedures

i. Data handling and quality control procedures

5. Emergency generator compliance reports. Within six months after initial installation of the emergency generator engine, the Permittee shall submit to EPA a report containing a copy of all records required by conditions III.I.8.b of this permit. Thereafter, within 30 days after the end of each calendar year, the Permittee shall submit to EPA a copy of all records required by conditions III.I.8.b.(iii) and (iv) pertaining to that calendar year.

6. Baghouse and vent filter compliance reports: Within six months after initial startup of the materials handling systems for the WCFU, and within 30 days after the end of each calendar year thereafter, the Permittee shall submit to EPA a report containing all records required by condition III.K.3 of this permit.

7. Fugitive dust control compliance reports. Within six months after initial startup of the materials handling systems for the WCFU, and within 30 days after the end of each calendar year thereafter, the Permittee shall submit to EPA a report containing all records required by condition III.I.8.c of this permit.

8. CFB boiler fuel restriction compliance reports. Within six months after initial startup of the CFB boiler, and within 30 days after the end of each calendar year thereafter, the Permittee shall submit to EPA a report containing the records on CFB boiler fuel required by condition III.I.8.a of this permit.

9. Notification of commencement of construction. Within 15 days after commencement of construction of the WCFU project, the Permittee shall notify EPA in writing that construction has commenced.

10. Addresses. The Permittee shall send all required notifications and reports to:

    Program Director
    Air and Radiation Program (8P-AR)
    U.S. EPA, Region 8
    1595 Wynkoop Street
    Denver, CO 80202-1129

M. New Source Performance Standards (NSPS). The following references to NSPS (40 CFR part 60) are merely intended to cite certain applicable NSPS requirements in summary form. These references are not intended to be a comprehensive and thorough listing of all applicable NSPS requirements.

In addition to the requirements of this permit, the following subparts of 40 CFR part 60 apply to the WCFU:

Subpart A – General Provisions

Subpart Da – Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978.

Subpart Y – Standards of Performance for Coal Preparation Plants

N. Title V Permitting Requirements. The following references to permitting requirements under Title V of the Clean Air Act and 40 CFR part 71 are merely intended to cite certain applicable requirements in summary form. These references are not intended to be a comprehensive and thorough listing of all applicable Title V requirements

1. Within twelve (12) months after commencing operation of the WCFU, the Permittee shall submit an application for a Title V Permit to Operate in accordance with 40 CFR part 71.

2. This Permit to Construct and Operate allows the construction and initial operation of the WCFU. The WCFU may be operated under this Permit to Construct and

Operate until the Title V Permit to Operate is issued, unless this permit is suspended or revoked. The WCFU is subject to all applicable Federal, State and Tribal rules, regulations, and orders now or hereafter in effect.

O. Acid Rain Program Requirements. The following references to Acid Rain Program, 40 CFR parts 72 through 78, are merely intended to cite certain applicable requirements in summary form. These references are not intended to be a comprehensive and thorough listing of all applicable Acid Rain Program requirements.

1. Permitting. At least twenty four (24) months before commencing operation of the WCFU, the Permittee shall submit an application for an Acid Rain Program permit in accordance with 40 CFR part 72.

2. Sulfur Dioxide Allowances. The Permittee shall comply with requirements under 40 CFR 72.9(c)(1) and 40 CFR part 73 for affected Acid Rain units to obtain and hold acid rain SO_2 allowances in the unit's compliance subaccount (after any applicable deductions), as of the allowance transfer deadline (defined in 40 CFR 72.2), not less than the total annual emissions of SO_2 for the previous calendar year from the unit, and to comply with the applicable Acid Rain emission limitation for SO_2.

3. Continuous Emission Monitoring Requirements. The Permittee shall comply with applicable continuous emission monitoring requirements under 40 CFR 75.

IV. General Conditions

On the basis of the findings set forth in section II of this permit, and pursuant to the authority (as delegated by the Administrator) of 40 CFR 52.21(u), EPA Region 8 hereby conditionally authorizes Deseret Power Electric Cooperative to construct the Waste Coal Fired Unit at the Bonanza power plant. This authorization is expressly conditioned as follows:

A. Binding Application: This permit is issued in reliance upon the accuracy and completeness of the information set forth in the Applicant=s application to EPA dated November 1, 2004, and subsequent information provided by the Applicant to EPA, as listed in the Administrative Record for issuance of this permit. Appendix A of the Statement of Basis for this permit contains a list of the documents in the Administrative Record.

The Permittee shall abide by all representations, statements of intent and agreements contained in the permit application and subsequent submittals as listed in the Administrative Record. EPA shall be notified no less than ten (10) days in advance of any significant deviation from the permit application as well as any plans, specifications or supporting data furnished. The issuance of this Permit to Construct and Operate may be suspended or revoked if EPA determines that a significant deviation from the permit application, specifications, and supporting data furnished has been or is to be made.

B. Permit Effective Date: This PSD Permit becomes effective 30 days after the service of notice of the final permit decision, unless review of the permit decision is requested pursuant to 40 CFR 124.19.

C. Enforceability of Permit: On the effective date of this permit, the conditions herein become enforceable by EPA pursuant to any remedies it now has or may have in the future, under the Clean Air Act.

D. Emissions During Construction: The Permittee shall take all reasonable precautions to prevent and or minimize fugitive emissions during the construction period.

E. Initial Notifications: The Permittee shall submit written notification to EPA of the anticipated date of initial start-up of the WCFU, not more than 60 days nor less than 30 days prior to such date. The Permittee shall submit notification to EPA of the actual date of commencement of construction and actual date of initial start-up, within 15 days after each such date. For purposes of this permit, "startup" shall mean the setting in operation of an affected facility for any purpose, and "affected facility' shall mean any apparatus, equipment, or emission unit subject to a standard in this permit, or in the applicable Standards of Performance for New Stationary Sources, found at 40 CFR 60, Subparts A, Da and Y.

F. Applicability of Other Requirements: This permit does not release or excuse the Permittee from compliance with any applicable Federal, Tribal and State regulations, nor from compliance with any other applicable Federal, Tribal and State requirements.

G. Transfer of Ownership: In the event of any changes in control or ownership of the facilities to be constructed under this permit, the permit is binding on all subsequent owners and operators. The Permittee shall notify, by letter, the succeeding owner and operator of the existence of this permit and its conditions. A copy of the letter shall be provided to the EPA. Permit transfers shall be made in accordance with 40 CFR part 122, subpart D.

H. Permit Expiration. As provided for in 40 CFR 52.21(r)(2), approval to construct under this permit shall become invalid if:

1. construction is not commenced within 18 months after receipt of such approval,

2. construction is discontinued for a period of 18 months or more, or

3. construction is not completed within a reasonable time.

The Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date.

I. Treatment of Emissions: Emissions in excess of the limits specified in this permit shall constitute a violation.

J. Right of Entry: For purposes of ascertaining compliance with this permit, the EPA Regional Administrator, and/or his authorized representative, upon the presentation of credentials, shall be allowed by the Permittee:

A. To enter the premises where the permitted facility is located, or where any records are required to be kept under the terms and conditions of this permit;

B. At reasonable times to have access to and copy any records required to be kept under the terms and conditions of this permit;

C. To inspect any equipment, operation, or method required under this permit; and

D. To sample emissions from the permitted facility.

Authorized By: United States Environmental Protection Agency, Region 8

Stephen S. Tuber
Stephen S. Tuber
Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

Date: 8/30/07

Exhibit 2

***Western Resource Advocates * Environmental Defense ***
Utah Chapter of the Sierra Club * Southern Utah Wilderness Alliance *
Western Colorado Congress * Wasatch Clean Air Coalition *
HEAL Utah*

By email owens.mike@epa.gov
Mike Owens
US EPA Region 8
Air and Radiation Program Office (8P-AR)
999 18th Street, Suite 300
Denver, CO 80202-2466

RE: Draft PSD Permit for Major Modifications to the Bonanza Power Plant in Utah

Dear Mr. Owens:

Western Resource Advocates, Environmental Defense, Utah Chapter of the Sierra Club, Southern Utah Wilderness Alliance, Western Colorado Congress, Wasatch Clean Air Coalition, and HEAL Utah respectfully submit the following comments on the EPA's draft prevention of significant deterioration (PSD) permit authorizing the construction of a new Waste Coal Fired Unit (WCFU) at Deseret Power Electric Cooperative's (Deseret) Bonanza Power Plant near Vernal, Utah.

1. THE DRAFT AIR QUALITY PERMIT DOES NOT ADDRESS CARBON DIOXIDE AND OTHER GREENHOUSE GAS EMISSIONS

The draft permit for the Bonanza WCFU does not address carbon dioxide (CO_2) or other greenhouse gases to be emitted from the proposed power plant. However, such emissions can be quite significant from coal-fire boilers and, in particular, from circulating fluidized bed (CFB) boilers such as is proposed for the Bonanza WCFU. The National Coal Council identifies fluidized bed combustion as an especially large source of the greenhouse gas nitrous oxide (N_2O), a problem that is not shared by the most common form of coal combustion technology, pulverized coal (PC):

> "N_2O has a GWP (Global Warming Potential) 296 times that of CO_2. Because of its long lifetime (about 120 years) it can reach the upper atmosphere, depleting the concentration of stratospheric ozone, an important filter of UV radiation. N_2O is emitted from fluidized bed coal combustion; global emissions from FBC units are 0.2 Mt/year, representing approximately 2% of total known sources. N_2O emissions from PC units are much lower. Typical N_2O emissions from FBC units are in the range of 40-70 ppm (at 3% O_2). This is significant because at 60 ppm, the N_2O emission from the FBC is equivalent to 1.8% CO_2, an increase of about 15% in CO_2 emissions for an FBC boiler. Several

techniques have been proposed to control N_2O emissions from FBC boilers, but additional research is necessary to develop economically and commercially attractive systems."[1]

The Bonanza WCFU has a potential to emit approximately 1.8 million tons of carbon dioxide each year and 3,609 tons of nitrous oxide each year.[2] The nitrous oxide that would be released from the Bonanza WCFU is equivalent, in Global Warming Potential, to an additional 1 million tons per year of carbon dioxide.

We believe that the EPA has a legal obligation to regulate CO_2 and other greenhouse gases as pollutants under the Clean Air Act. Indeed, twelve states, fourteen environmental groups and two cities filed suit stating that EPA must regulate greenhouse gas emissions under the Clean Air Act. The parties appealed the U.S. EPA's decision to reject a petition that sought to have the federal government regulate greenhouse gas emissions from new motor vehicles.[3] This issue is now before the U.S. Supreme Court. If the Supreme Court agrees that greenhouse gases, such as CO_2, must be regulated under the Clean Air Act, such a decision may also require the establishment of CO_2 emission limits in this permit for the Bonanza WCFU.

At the minimum, EPA must consider emissions of CO_2 in its BACT analysis for the Bonanza WCFU. The federal Environmental Appeals Board (EAB) has interpreted the definition of BACT as requiring consideration of unregulated pollutants in setting emission limits and other terms of a permit, since a BACT determination is to take into account environmental impacts.[4] A recently issued paper entitled *Considering Alternatives: The Case for Limiting CO_2 Emissions from New Power Plants through New Source Review* by Gregory B. Foote (Attachment 2) discusses the regulatory background to support consideration of CO_2 impacts when permitting a new source and, in particular, a new coal-fired power plant. This paper indicates that it is entirely appropriate to consider CO_2 emissions when evaluating environmental impacts under the new source review permit program, and the paper also suggested approaches for evaluating technologies in terms of CO_2 emissions. This paper and all other documents cited herein are incorporated by reference as part of our comments. Support for consideration of greenhouse gas emissions in new source permitting can also be found in EPA's own New Source Review Workshop Manual which states, "significant differences is noise levels, radiant heat, or dissipated static electrical energy, or greenhouse gas

[1] "Coal-Related Greenhouse Gas Management Issues", National Coal Council, May 2003 at page 7. Attachment 1.
[2] Emissions of CO_2 and N_2O were calculated based on AP-42 emission factors for bituminous coal combustion in fluidized bed boilers, the average carbon content of the waste coal and on the expected annual coal feed rate at the Bonanza WCFU (from page 19 and from Appendix A of Deseret's November 1, 2004 PSD permit application).
[3] Commonwealth of Massachusetts, et al. v. U.S. EPA, No. 03-1361 (Consolidated with Nos. 03-1362-1368) U.S. Court of Appeals for the District of Columbia Circuit, *cert. granted* U.S. Supreme Court Docket 05-1120.
[4] See *In Re North County Resource Recovery Associates*, 2 E.A.D. 229, 230 (Adm'r 1986), 1986 EPA App. LEXIS 14.

emissions may be considered" in permitting a new source or in the application of a specific technology. *See,* Attachment 22 hereto.

2. THE DRAFT AIR QUALITY PERMIT DID NOT ADEQUATELY EVALUATE INTEGRATED GASIFICATION COMBINED CYCLE AS AN AVAILABLE METHOD TO LOWER AIR EMISSIONS IN THE BACT ANALYSIS

EPA's Statement of Basis for the draft Bonanza WCFU permit explains that it did not require evaluation of IGCC as BACT because consideration of IGCC would be redefining the source. Statement of Basis at 29.

EPA made a similar determination on December 13, 2005 that IGCC did not need to be reviewed as BACT for a supercritical pulverized coal boiler because it would be redefining the source. This December 2005 determination has been challenged and that challenge has not yet been resolved. NRDC v. EPA, D.C. Circuit, No. 06-1059.

The EPA's determination that IGCC need not be considered because it would be redefining the Bonanza WCFU source, similar to EPA's December 2005 determination, is wrong. BACT by its Clean Air Act definition requires consideration of inherently lower emitting processes.

Integrated Gasification Combined Cycle (IGCC) is an available, demonstrated cleaner coal combustion technology with significant emission reduction benefits. There are numerous benefits to IGCC, including fewer emissions of criteria and hazardous air pollutants, the opportunity for capturing greenhouse gases, such as CO_2, that cause global warming, and a general increase in efficiency over other coal burning technologies and thus lower overall emissions.

<u>Federal Law Requires a Thorough Evaluation of IGCC as Part of the BACT Analysis</u>.

Section 165(a)(4) of the Clean Air Act (CAA) provides that "no major emitting facility on which construction is commenced after August 7, 1977, may be constructed in any area to which this part applies unless...the facility is subject to the best available control technology for each pollutant subject to regulation under this chapter emitted from, or which results from, such facility."[5] The requirement for conducting a BACT analysis is codified in the federal PSD regulations at 40 C.F.R. § 52.21(j). 40 C.F.R. § 52.21(n) further requires that "the owner or operator of a proposed source. . . shall submit. . .all information necessary to perform any analysis or make any determination" required under the PSD regulations."

BACT is then defined under federal law as follows:

> an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each pollutant subject to regulation under the [Clean Air] Act which would be emitted from any proposed

[5] 42 U.S.C. §7475(a)(4).

major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application or production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.[6]

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

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

Mr. MUSKIE. Mr. President, I have also discussed this amendment with the distinguished Senator from Kentucky. I think it has been worked out in a form I can accept. I am happy to do so. I am willing to yield back the remainder of my time.[7]

EPA and federal courts have consistently interpreted the BACT provisions found in the CAA and the agency's regulations as embodying certain core criteria that require the permit applicant either to implement the most effective available means for minimizing air pollution or justify its selection of less effective means on grounds

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[6] 40 C.F.R. §52.21(b)(12), emphasis added. See also 42 U.S.C. §7479(3).
[7] 95th Congress, 1st Session (Part 1 of 2) June 10, 1977 Clean Air Act Amendments of 1977 A&P 123 Cong. Record S9421.

consistent with the purposes of the Act. In *Citizens for Clean Air v. EPA*,[8] the Ninth Circuit held that "initially the burden rests with the PSD applicant to identify the best available control." As stated in long-standing EPA guidance, "[r]egardless of the specific methodology used for determining BACT, be it 'top-down,' 'bottom-up,' or otherwise, the same core criteria apply to any BACT analysis: the applicant must consider all available alternatives, and [either select the most stringent of them or] demonstrate why the most stringent should not be adopted."[9] Accordingly, the PSD permit applicant not only must identify all available technologies, including the most stringent, but it must also provide adequate justification for dismissing any available technologies.

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

> The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant. This includes technologies employed outside of the United States. As discussed later, in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.[10]

"The term 'available' is used…to refer to whether the technology 'can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term.'"[11] In keeping with the stringent nature of the BACT requirement, EPA has repeatedly emphasized that "available"

> is used in the broadest sense under the first step and refers to control options with a "practical *potential* for application to the emissions unit" under evaluation. . . . The goal of this step is to develop a comprehensive list of control options.[12]

[8] 959 F.2d 839, 845 (9th Cir. 1992)
[9] Memorandum from John Calcagni, Director of EPA Air Quality Management Division, to EPA Regional Air Directors (June 13, 1989), at 4 (emphasis added).
[10] NSR Manual, at p. B.5 (emphasis added).
[11] In re: Maui Electric Company, PSD Appeal No. 98-2 (EAB September 10, 1998), at 29-30 (quoting NSR Manual at B.17).
[12] In re: Knauf Fiber Glass, PSD Appeal Nos. 98-3 – 98-20 (EAB February 4, 1999), at 12-13 (quoting NSR Manual at B.5) (emphasis added by EAB); see also In re: Steel Dynamics, Inc., PSD Appeal Nos. 99-4 and 99-5 (EAB June 22, 2000), at 29 n.24 (citing Knauf with approval); NSR Manual at B.10 ("The

EPA adjudicatory decisions also examine the core requirements for the BACT determination process. "Under the top-down methodology, applicants must apply the best available control technology unless they can demonstrate that the technology is technically or economically infeasible. The top-down approach places the burden of proof on the *applicant* to justify why the proposed source is unable to apply the best technology available."[13]

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

Thus, to conduct a BACT analysis consistent with the requirements of federal law for the Bonanza WCFU, EPA must thoroughly evaluate all available control measures. IGCC is commercially available today. Federal law therefore require that this technology be thoroughly evaluated as part of the Bonanza WCFU BACT analysis.

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

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

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

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

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objective in step 1 is to identify all control options with potential application to the source and pollutant under evaluation."); <u>id.</u> at B.6 (emphasizing that a proper Step 1 list is "comprehensive").

[13] <u>In re: Spokane Regional Waste-to-Energy Applicant</u>, PSD Appeal No. 88-12 (EPA June 9, 1989), at 9) (internal quotation marks omitted) (emphasis in original); <u>see also</u> <u>In re: Inter-Power of New York, Inc.</u> PSD Appeal Nos. 92-8 and 92-9 (EAB March 16, 1994) ("Under the 'top-down' approach, permit applicants must apply the most stringent control alternative, unless the applicant can demonstrate that the alternative is not technically or economically achievable."); <u>In the Matter of Pennsauken County, New Jersey Resource Recovery Facility</u>, PSD Appeal No. 88-8 (EAB November 10, 1988) ("Thus, the 'top-down' approach shifts the burden of proof to the applicant to justify why the proposed source is unable to apply the best technology available.")

that must be addressed in the BACT demonstration for the proposed plant. In addition, based on the various demonstration projects that have been completed for IGCC, the Illinois EPA believes that IGCC constitutes a technically feasible production process.

Accordingly, Indeck must provide detailed information addressing the emission performance levels of IGCC, in terms of expected emissions rates and possible emission reductions, and the economic, environmental and/or energy impacts that would accompany application of IGCC to the proposed plant. This information must be accompanied by copies of relevant documents that are the basis of or otherwise substantiate the facts, statements and representations about IGCC provided by Indeck. In this regard, Indeck as the permit applicant is generally under an obligation to undertake a significant effort to provide data and analysis in its application to support the determination of BACT for the proposed plant.[14]

In an ensuing letter, the State of Illinois then formally informed EPA that Illinois has "concluded that it is appropriate for applicants for [proposed coal-fired power plants] to consider IGCC as part of their BACT demonstrations."[15]

Similarly, the Georgia Department of Natural Resources, in a March 2002 letter regarding the permit application of Longleaf Energy Station, also relied, in part, on the failure of the permit applicant to consider cleaner coal combustion technology in finding the application deficient. In making its determination of deficiency, Georgia stated that the applicant did not "discuss any other methods from generating electricity from the combustion of coal, such as pressurized fluidized bed combustion or integrated gasification combined cycle."[16] Georgia further stated that the applicant "should discuss these technologies and explain why you elected to propose a pulverized coal-fired steam electric power plant instead."[17]

Reflecting the viability of IGCC, the State of New Mexico issued a letter on December 23, 2002 requiring the permit applicant for a new coal-fired power plant to conduct a site-specific analysis of IGCC as well as CFB as part of the BACT analysis for the proposed facility: "The Department requires a site-specific analysis of IGCC and CFB in order to make a determination regarding BACT for the proposed facility." The New Mexico determination goes on to provide: "The analysis must include a discussion of the technical feasibility and availability of IGCC and CFB for the proposed site in McKinley County, including a discussion of existing IGCC and CFB systems."[18]

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

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

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

[17] Id.

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

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

> Mustang concludes that neither IGCC nor CFB are technically feasible control options for the Mustang site. After careful review of the revised BACT analysis, as well as information gathered from independent sources, the Department determines that Mustang's conclusion is not supported by the evidence. Accordingly, the Department finds that Mustang has not demonstrated the technical infeasibility of IGCC and CFB. Moreover, applying the criteria in the NSR Manual, the Department determines that IGCC and CFB are technically feasible at the Mustang site, and must be evaluated in the remaining steps of the top down BACT methodology.
>
> (a) IGCC and CFB are technically feasible at the Mustang site. A technology is considered to be technically feasible if it is commercially available and applicable to the source under consideration. *See* NSR Manual at B.17-18. A technology is commercially available if it has reached a licensing and commercial sales stage of development. *Id.* A technology is applicable if it has been specified in a permit for the same or a similar source type. *Id.* Mustang's revised BACT analysis indicates that IGCC is commercially available, and IGCC has been specified in air quality permits for coal-fired power plants. *See, e.g.,* Lima Energy Facility, 580 megawatt coal-fired power plant. Similarly, CFB is commercially available and has been specified in air quality permits for coal-fired power plants. *See, e.g.,* AES Puerto Rico 454 megawatt coal-fired power plant; Reliant Energy Seward 584 megawatt coal-fired power plant.
>
> (b) For both IGCC and CFB, Mustang improperly relies on cost to determine technical *infeasibility*. A technology is technically feasible when the resolution of technical difficulties is a matter of cost. *See* NSR Manual at B.19-20. Mustang's revised BACT analysis indicates that the resolution of technical difficulties for both IGCC and CFB are a matter of cost. These costs do not support a finding of technical infeasibility, but may be considered during Step 4 of the top down BACT methodology. *See* NSR Manual at B.26.[19]

In addition, the Montana Board of Environmental Review found that Montana Department of Environmental Quality must consider IGCC as an available technology in the BACT review for a coal-fired power plant. Specifically, the Board of Environmental Review stated ". . .the Department should require applicants to consider innovative fuel

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

combustion techniques in their BACT analysis and the Department should evaluate such techniques in its BACT determination in accordance with the top-down five-step method."[20]

While we recognize that state decisions on this matter do not necessarily set the bar for EPA, it is noteworthy that these states determined it was entirely appropriate to require consideration of IGCC in the BACT review for a coal-fired power plant. The aforementioned state determinations are attached hereto.

<u>EPA Region 8 Previously Determined It Was Appropriate to Evaluate IGCC in the BACT Analysis for a CFB Coal-Fired Power Plant</u>

Further, EPA Region 8 submitted comments to the Utah Division of Air Quality in an April 6, 2004 letter on Utah's proposed permit for NEVCO Energy's Sevier Power Company Project in which EPA requested that further documentation on costs be provided to support Utah's claim that IGCC was too costly.[21] EPA did not indicate that IGCC didn't need to be considered as an alternative for the proposed Sevier CFB boiler. Instead, EPA stated "It is our understanding that IGCC is a potentially lower polluting process than Circulating Fluidized Bed combustion." EPA's comments requesting more documentation of the costs of IGCC provide strong indication that EPA found it appropriate to consider IGCC in the BACT analysis. In addition, EPA also found IGCC to be a lower polluting process to a CFB boiler such as the boiler to be used at the Bonanza WCFU.

EPA Region VIII also initially requested Deseret to provide information regarding IGCC as an alternative to its planned CFB boiler. Specifically, at an April 28, 2004 meeting with Deseret, EPA requested an explanation of why Deseret ruled out IGCC.[22] Although EPA Region 8 and Deseret exchanged correspondence on IGCC several times, EPA Region 8 ultimately decided that IGCC was *not* a BACT option ". . .because it would fundamentally change the basic design of the proposed source."[23] For all of reasons discussed above, we contend that IGCC *is* an option that is required to be evaluated in a BACT determination under the Clean Air Act and associated regulations for a new coal-fired power plant such as the Bonanza WCFU. EPA unlawfully eliminated IGCC from review in the BACT determination as redefining the source.

3. EPA FAILED TO REQUIRE CONSIDERATION OF A SUPERCRITICAL CFB BOILER IN THE BACT ANALYSIS FOR THE BONANZA WCFU

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

[21] April 6, 2004 letter from Richard R. Long, EPA, to Rick Sprott, Utah Division of Air Quality, at 1 (Attachment 8).

[22] See Enclosure 1 to November 22, 2004 letter from Richard R. Long, EPA, to Ed Thatcher, Deseret Power, at 1.

[23] Statement of Basis at 29.

Deseret and EPA should have also considered the construction of a supercritical CFB boiler. Supercritical CFB boilers are more efficient and thus use less fuel and emit less carbon dioxide emissions. This technology is discussed in the Western Governor's Association Technology Working Group's report on advanced clean coal technologies (Attachment 9). EPA must require evaluation of this inherently lower emitting technology in its BACT review for the Bonanza WCFU.

4. THE PROPOSED BACT EMISSION LIMITS FAIL TO REFLECT THE MAXIMUM LEVEL OF CONTROL THAT CAN BE ACHIEVED

EPA Did Not Properly Analyze Whether Cleaner Coals Could Be BACT

While EPA did provide a cost analysis of using all "run-of-mine" coal from the Deserado mine and the resultant additional pollutant reductions (Statement of Basis at 24-28), EPA did not provide a comparison of the cost of using "run-of-mine" coal, either in part or wholly, compared to the cost other coal-fired electric utility CFB boilers in the region are paying for coal. EPA also did not provide any comparative cost analysis for use of coal from other mines in the region, either wholly or in part as a blend with the Deserado waste coal. Such analyses are necessary to give context to this evaluation. (See, e.g., In RE Inter-Power of New York. Inc., PSD Appeal Nos. 92-8 and 92-9, Decided March 16, 1994). In determining whether the cost of a control technology is reasonable, the cost must be compared to what other similar sources have had to bear.[24]

For example, EPA should have provided a comparison to the recently permitted Sevier Power Company's CFB power plant to be located in Sigurd, Utah. That facility will be burning a higher quality bituminous coal than the waste coal proposed for the Bonanza WCFU, which will be from the Sufco Mine or other Utah coal sources with coal heating value in the range of 10,200 – 12,000 Btu/lb, sulfur content in the range of 0.25-0.9%, and ash content in the range of 6.5-12%.[25] It also will be equipped with virtually the same pollution control equipment as proposed for the Bonanza WCFU. The Sevier Power Company's CFB boiler is subject to lower emission limits for SO_2 (0.022 lb/MMBtu, 30-day average limit, as compared to the Bonanza WCFU proposed variable limit of 0.04 – 0.055 lb/MMBtu), total PM/PM_{10} (0.0154 lb/MMBtu as compared to the Bonanza WCFU proposed limit of 0.03 lb/MMBtu), carbon monoxide (CO) (0.115 lb/MMBtu as compared to the Bonanza WCFU proposed limit of 0.15 lb/MMBtu), and sulfuric acid (H_2SO_4) (0.0024 lb/MMBtu as compared to the Bonanza WCFU proposed limit of 0.0035 lb/MMBtu). A copy of the Sevier Power Company permit is attached. (Attachment 10).

EPA must analyze and provide data on the cost and quality of coal that the Sevier Power Company and other recently proposed power plants in the region are required to incur before it can determine that the cost of using "run-of-mine" fuel from the Deserado mine – either wholly or in part – is unreasonable. EPA also must provide a similar

[24] See U.S. EPA, New Source Review Workshop Manual, October 1990 Draft, at B.29.
[25] See Utah Division of Air Quality New Source Plan Review for the Sevier Power Company, December 29, 2003, at 8, 13. (Attachment 11).

analysis for using other higher quality coal available in the region, either wholly or as a blend with the waste coal.

The SO_2 Emission Limit Does Not Reflect BACT

The proposed BACT limit for SO_2 and BACT analyses are flawed because they do not reflect the maximum degree of reduction that can be achieved. EPA has proposed an SO_2 emission limit of 0.055 lb/MMBtu (30-day average) when the uncontrolled SO_2 emissions are 1.9 lb/MMBtu or greater. (Condition III.D.1.b.(ii) of the draft permit). EPA has also proposed a calculated 30-day average SO_2 limit which is based on a 0.055 lb/MMBtu emission rate for the number of days at which the uncontrolled SO_2 emissions were 1.9 lb/MMBtu or higher, and a 0.04 lb/MMBtu limit for the number of days at which the uncontrolled SO_2 emissions were less than 1.9 lb/MMBtu.

Neither of these limits in EPA's proposed variable BACT limit reflect the maximum degree of reduction that can be achieved at a CFB boiler. First, two different coal-fired CFB power plants have been required to meet an SO_2 BACT limit of 0.022 lb/MMBtu, which is much lower than the proposed BACT limit at the Bonanza WCFU which would range from 0.040 to 0.055 lb/MMBtu. Specifically, the Sevier power plant in Utah, a 270 MW bituminous coal-fired CFB power plant to be equipped with a circulating dry scrubber, was required in its October 2004 PSD permit to meet an SO_2 BACT emission limit of 0.022 lb/MMBtu on a 30-day average. A copy of the final permit for the Sevier power plant is attached. (Attachment 10).

In addition, the 2 unit, 454 megawatt AES-Puerto Rico CFB plant, also equipped with a circulating dry scrubber, is required to burn low sulfur coal (1% or less) and meet a 0.022 lb/MMBtu SO_2 limit *on a three-hour average*. A copy of the final permit for AES-Puerto Rico is attached (Attachment 13). Based on the worst-case coal quality to be used at AES-Puerto Rico (0.8% and 12,000 BTU/lb), the uncontrolled SO_2 emission rate of AES-Puerto Rico is 1.6 lb/MMBtu, thus this emission limit equates to a 98.6% reduction in SO_2 emissions. The AES-Puerto Rico permit is significant in that the worst case uncontrolled emissions are much less than the worst case uncontrolled emissions and also less than the average uncontrolled SO_2 emission rate expected at the Bonanza WCFU, and yet still a very high level of SO_2 control is required. This limit, especially given the short averaging time, counters Deseret's arguments that SO_2 removal efficiency will decrease with decreasing uncontrolled SO_2 emissions.[26]

While EPA claimed in its Statement of Basis that 98.8% SO_2 removal could be achieved with the CFB boiler and the spray dry absorber (Statement of Basis at 72, 73), the proposed BACT emission limit for SO_2 does not reflect this level of control because it is based on the absolute worst case uncontrolled SO_2 emission rate. The 0.055 lb/MMBtu limit reflects 98.8% SO_2 removal from the worst case design coal of 3,000 Btu/lb and 0.71% sulfur (which thus equates to an uncontrolled SO_2 emission rate of 4.73 lb/MMBtu). However, the expected *average* uncontrolled SO_2 emission rate is 1.71 (EPA's Statement of Basis at 15). Based on the average uncontrolled SO_2 emission rate,

[26] See November 9, 2005 email from Ed Thatcher, Deseret, to Mike Owens, EPA Region 8, at 1.

the 0.040 lb/MMBtu SO_2 limit (which would apply when the uncontrolled emission rate is lower than 1.9 lb/MMBtu) only represents a 97.7% SO_2 removal rate from average uncontrolled SO_2 emissions, over a percentage point lower than the maximum degree of reduction that can be achieved.

EPA Region 8 previously made a similar comment to the Montana Department of Environmental Quality regarding the proposed Roundup power plant. Indeed, EPA stated "[w]hile use of the worst-case coal scenario might be appropriate for establishing a short-term (3-hour or 24-hour) SO_2 emission limit, we consider it inappropriate for establishing a 30-day average emission limit, especially considering that coal blending can be used at minimal additional cost (and is routinely used in the power plant industry) to eliminate or reduce the effect of coal sulfur 'spikes.'"[27] The Bonanza WCFU has requested to be authorized to burn washed or run-of-mine coal which will have lower uncontrolled SO_2 emissions than the worst case waste coal and thus which could be used to eliminate coal sulfur spikes.[28] Also, Deseret has indicated that the Bonanza WCFU will have continuous SO_2 monitoring at the inlet to the dry scrubber.[29] Thus, Deseret will know on a fairly instantaneous basis when the coal sulfur content is spiking and thus could adjust the fuel accordingly. Consequently, the 30-day average BACT limit should reflect this level of control off of the average uncontrolled SO_2 emission rate of 1.71 lb/MMBtu, which equates to a BACT emission limit of 0.021 lb/MMBtu. Or, at worst, the 30-day average SO_2 emission limit should reflect the percent reduction required at the AES-Puerto Rico facility which has a similar level of uncontrolled emissions (albeit, worst case coal at AES-Puerto Rico is similar to average coal at the Bonanza WCFU). That facility's SO_2 emission limit reflects 98.6% reduction from uncontrolled emissions of 1.6 lb/MMBtu, on a three-hour average basis. Thus, the Bonanza WCFU SO_2 BACT limit should no higher than 0.024 lb/MMBtu, on a 30-day average to allow for the wide variability in sulfur content of the fuel.

As discussed further below in our comment letter, EPA must also impose shorter term averaging time BACT limits consistent with the averaging times of the SO_2 NAAQS and PSD increments (i.e., 3-hour and 24-hour). As EPA stated to Montana, we believe it is more appropriate to base shorter term average BACT limits on worst case uncontrolled emissions. Thus, the proposed BACT limit of 0.055 lb/MMBtu would be appropriate on a shorter term averaging time such as a three-hour average (similar to the AES-Puerto Rico permit). In addition, with a 30-day average SO_2 BACT limit based on average coal quality and a 3-hour average SO_2 BACT limit based on worst case coal quality, this would eliminate the need for EPA's proposed variable SO_2 limit which we find would not result in the maximum degree of SO_2 emission reduction that could be achieved. This is because EPA allows applicability to the variable SO_2 BACT limit to be based on a 30-day average of the uncontrolled SO_2 emission rate (Condition III.J.2. of the draft permit),

[27] See December 18, 2002 letter from Richard R. Long, EPA Region 8, to Steve Welch, Montana Department of Environmental Quality, at 2. (Attachment 12).
[28] Indeed, Deseret has requested the ability to blend waste coal with "run-of-mine" coal in order to comply with emission limits. See April 10, 2006 email from Ed Thatcher, Deseret, to Mike Owens, EPA Region 8.
[29] See Attachment to January 9, 2006 email from Ed Thatcher, Deseret, to Mike Owens, EPA Region 8, entitled "SO2 Control for the Deseret Circulating Fluidized Bed Boiler" at 1.

which will allow the Bonanza WCFU to only have to comply with the higher SO_2 BACT limit with just a few days of spiked coal sulfur content over a 30-day period. Further, the 5-day lag in comparing 30-day average uncontrolled SO_2 emissions to 30-day average controlled emission rates (Condition III.D.1.b.(ii)*(b)* of the draft permit) means that the proposed BACT emission limits would not ensure maximum SO_2 emission reductions on a continuous basis.

The draft permit also fails to address BACT requirements when Deseret is using "run-of-mine" coal either in lieu of waste coal, or as a blend with waste coal, from the Deserado mine. (As allowed by Condition III.E.2.c. of the draft permit). As indicated by EPA in correspondence to Deseret, BACT needs to be met "for the entire range of operating conditions."[30] Yet, EPA did not provide any review of BACT or propose any emission limits to address BACT when the Bonanza WCFU is burning the much higher quality coal either wholly or in part. To address this variation expected in uncontrolled SO_2 emissions at the Bonanza WCFU, EPA must include a SO_2 removal efficiency requirement as BACT in addition to the BACT emission limits that reflects the maximum degree of emission reduction that can be achieved given the variability in uncontrolled SO_2 emissions. EPA Region 8 recommended a similar approach in its comments on the proposed Roundup power plant in Montana. Specifically, EPA stated "[a] minimum required SO_2 scrubber efficiency should be included in the permit, to ensure proper operation and maintenance of the scrubber, and to ensure that SO_2 emissions are minimized at all times, regardless of the sulfur content in the coal."[31] However, contrary to EPA's approach in the proposed limits in this permit, the percent reduction BACT requirement must be based on at least a daily average. Given the wide variability of uncontrolled SO_2 emissions allowed by the permit, calculating uncontrolled SO_2 emissions on a 30-day average would not ensure the maximum degree of SO_2 emissions reductions on those days when 100% "run-of-mine" coal is being burned. Thus, to be meaningful, a 24-hour average percent SO_2 removal required as part of the BACT determination would effectively cover all of the various operating scenarios at the Bonanza WCFU.

For all of the above reasons, the SO_2 BACT analysis is flawed and must be revised accordingly.

<u>The NO_x BACT Limit Does Not Reflect BACT</u>

EPA Region 8 did not adequately evaluate all of the technologies that could be employed at the Bonanza WCFU to reduce NO_x emissions and, thus, its NO_x BACT determination does not reflect the maximum degree of NO_x reduction that can be achieved at the Bonanza WCFU.

First, EPA eliminated evaluation of several NO_x control options as infeasible for a CFB boiler. Those options eliminated include flue gas recirculation and overfire air. See Statement of Basis at 30. Yet, a 1999 EPA guidance document identifies these two

[30] See April 7, 2006 email from Mike Owens, EPA Region 8, to Ed Thatcher, Deseret.
[31] *Id.* at 3.

controls as options for NO_x control at CFB boilers.[32] Further, this 1999 EPA guidance document also identifies several other options for NO_x control at fluidized bed boilers that were not evaluated in the Bonanza WCFU NO_x BACT analysis, including natural gas reburn, low excess air, reduced air preheat, as well as reducing residence time at peak temperature through injection of steam, fuel reburning, non-thermal plasma reactor, and sorbent in combustion chamber/duct.[33] Thus, these technologies should have been evaluated by EPA, possibly in combination with SCR and SNCR, to determine the maximum degree of NO_x reduction that can be achieved.

While EPA required evaluation of selective catalytic reduction (SCR) on the proposed CFB boiler, SCR was improperly eliminated from the BACT review. First, EPA required evaluation of low temperature SCR, but Deseret apparently found that low temperature SCR was only applied to natural gas applications.[34] In a memorandum from Don Shepherd to John Notar, both of the National Park Service Air Resources Division, regarding the NEVCO Energy – Sevier Power – Engineering Analysis, Mr. Shepherd stated "[w]hen the question of application of SCR to a CFB was raised at the Pittsburgh workshop [on selective catalytic reduction and non-catalytic reduction for NO_x control], one consultant stated that he knew of no reason why it could not be done. (In fact, one presenter in Pittsburgh suggested that addition of limestone, as would be inherent in a CFB, is desirable in counteracting the potential catalyst-poisoning effects of arsenic found in many coals)."[35] Thus, the question that should have been posed is if SCR *could* be applied to coal-fired CFB boilers. As discussed in the EPA's New Source Review Workshop Manual, opportunities for technology transfer must be identified and evaluated in the BACT analysis.[36]

In addition, while EPA did require the evaluation of whether the flue gas downstream of the baghouse could be reheated to the temperature range "known to be effective for SCR use (650-750 F)" (Statement of Basis at 32), EPA should also have required evaluation of reheating the gas stream to the temperature range at which low temperature SCR could be used. According to the Institute of Clean Air Companies, low temperature catalysts can work in the range of 350 – 550 F.[37] Thus, EPA should have required Deseret to evaluate heating the gas stream up to 350 F and using low temperature SCR, which would use considerably less fuel than needed to reheat the gas stream to 650 F.

In addition, the presumed emission limit that could be met with SCR should have been lower than 0.04 lb/MMBtu. Statement of Basis at 33. EPA did not provide any rationale for this presumed NO_x emission rate with SCR, except to cite to the level assumed by North Dakota in its BACT analysis for Gascoyne. *Id.* Instead, EPA should have evaluated a NO_x emission limit based on the maximum degree of emission

[32] Technical Bulletin Nitrogen Oxides (NOx), Why and How They Are Controlled, US E.P.A., EPA456/F-99-006R (November 1999), at 28.
[33] *Id.*
[34] Statement of Basis at 32.
[35] See November 4, 2003 Memorandum from Don Shepherd to John Notar, at 2, Attachment 14.
[36] See New Source Review Workshop Manual, U.S. EPA, October 1990 Draft, at B.11.
[37] http://www.icac.com/i4a/pages/index.cfm?pageid=3399 (Under NOx Control Technologies)

reduction that can be achieved with SCR. According to Babcock & Wilcox, commercial SCR installations have shown that 90% NO_x reductions can be achieved with low ammonia slip.[38] Indeed, Babcock & Wilcox states that up to 95% NO_x control can be achieved with SCR. Thus, considering the NO_x emission rate without SCR of 0.15 lb/MMBtu, which EPA indicated was an overestimate of NO_x emissions expected from the Bonanza WCFU (Statement of Basis at 34-35), the appropriate NO_x emission rate with SCR to evaluate would be at most 0.015 lb/MMBtu rather than the assumed 0.04 lb/MMBtu.

Thus, the analysis for SCR must be re-evaluated to consider whether low temperature SCR could work on the Bonanza CFB boiler, either without or with flue gas reheating, and considering a NO_x emission rate that reflects the maximum degree of emission reduction that can be achieved. Further, in determining whether the costs are reasonable, the costs must be compared to the costs other coal-fired electric utility boilers have had to bear for NO_x control under BACT determinations.[39] It is not appropriate to compare to the cost of SNCR, which is less effective in reducing NO_x.

If EPA determines that SCR can be eliminated, after revising the BACT review in light of our comments above, then its evaluation of SNCR and the associated NO_x emission limit must be based on the maximum degree of emission reduction achievable with SNCR. SNCR should be able to reduce NO_x emissions by at least 50%[40] Yet, EPA's proposed 0.080 lb/MMBtu NO_x emission limit for SNCR reflects only a 47% NO_x reduction.[41] Assuming 50% NO_x reduction with SCNR would equate to an emission limit of 0.075 lb/MMBtu, or even lower considering that EPA believes the 0.15 lb/MMBtu uncontrolled NO_x emission rate is an overestimate. Statement of Basis at 34-35. Further, as EPA pointed out to Deseret in its July 8, 2005 letter, there are several other proposed CFB boilers using SNCR with proposed NO_x emission limits of 0.07 lb/MMBtu including the Estill County Energy Partners Project in Kentucky, the Kentucky Mountain Power Project in Kentucky and the River Hill project in Pennsylvania[42]. As EPA commented to Deseret, the Estill County project is most similar to Bonanza in size and coal quality, and thus Deseret should be able to meet a similar limit at the Bonanza WCFU. Although Deseret later pointed out that no PSD permit had been issued for the Estill County project yet,[43] that does not negate the point that the owners/operators proposed a 0.07 lb/MMBtu NO_x limit for their facility. Thus the NO_x BACT analysis for SNCR should be evaluated using a lower NO_x limit, in the range of 0.07 to 0.075 lb/MMBtu to ensure that the limit reflects the maximum degree of NO_x reduction that can be achieved.

[38] See Bielawski, G.T., J.B. Rogan, and D.K. McDonald, How Low Can We Go? Controlling Emissions in New Coal-Fired Power Plants, Presented to the U.S. EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Symposium: "The Mega Symposium," August 2001. (Attachment 17.)

[39] See U.S. EPA, New Source Review Workshop Manual, October 1990 Draft, at B.29.

[40] See May 2, 2005 Commonwealth of Pennsylvania's Plan Approval Application Review Memo for the River Hill Power Company, LLC, at 27, attached to the May 26, 2005 email from Don Shepherd, National Park Service, to Hans Buenning, EPA Region 8.

[41] Based on an uncontrolled NOx emission rate of 0.15lb/MMBtu, Statement of Basis at 34-35.

[42] July 8, 2005 letter from Richard R. Long, EPA Region 8, to Ed Thatcher, Deseret, at 3.

[43] December 20, 2005 email from Ed Thatcher, Deseret, to Mike Owens, EPA Region 8.

The draft permit also fails to address BACT requirements when Deseret is using "run-of-mine" coal either in lieu of waste coal, or as a blend with waste coal, from the Deserado mine. (As allowed by Condition III.E.2.c. of the draft permit). As indicated by EPA in correspondence to Deseret, BACT needs to be met "for the entire range of operating conditions."[44] Yet, EPA did not provide any review of BACT or propose any emission limits to address BACT when the Bonanza WCFU is burning the much higher quality coal either wholly or in part. As discussed above, such a BACT limit must be imposed on a 24-hour average basis to ensure the maximum degree of NO_x emission reduction is required when 100% "run-of-mine" coal is being burned.

EPA's Proposed Limit for Total PM/PM_{10} Does Not Reflect BACT

EPA has proposed a limit for total PM/PM_{10} of 0.03 lb/MMBtu, 30-day rolling average. However, as shown in the data provided by EPA in its Statement of Basis, this limit does not reflect the maximum degree of reduction that can be achieved. Specifically, EPA identifies several other CFB boilers with similar pollution controls as proposed for the Bonanza WCFU with lower total PM/PM_{10} limits. Statement of Basis at 57. Six of the 8 CFB boiler permits reviewed by EPA had lower total PM limits than the proposed 0.03 lb/MMBtu. Three of the 8 permits reviewed had limits on total PM of 0.012 lb/MMBtu. EPA readily discounted these emission limits, but without any review of the specific details behind these emission limits (such as how the sources calculated these emission limits). Statement of Basis at 58. While EPA did not discount the total PM emission limits of the three proposed facilities in Region 8 (Highwood, Gascoyne, and South Heart), which ranged from 0.0232 lb/MMBtu – 0.026 lb/MMBtu, EPA did not ultimately find that the methodology consistently used by these three facilities for calculating condensable PM emissions was appropriate for the Bonanza WCFU and instead allowed Bonanza's overestimate of ammonium sulfate to dictate the level of the total PM BACT limit. Statement of Basis at 55-56. Even the actual stack test data for similar sources is lower than EPA's proposed total PM BACT limit, with results ranging from 0.004 lb/MMBtu to 0.023 lb/MMBtu using EPA Method 202. Statement of Basis at 59. Thus, the majority of the data provided by EPA in its Statement of Basis indicate that its proposed total PM/PM_{10} BACT limit fails to reflect the maximum degree of emission reduction that can be achieved as required by the definition of BACT. While EPA claims its proposed 0.03 lb/MMBtu emission limit incorporates a "margin of safety," the margin of safety is too lenient.

In addition, due to the deficiencies in EPA's 0.03 lb/MMBtu BACT determination for total PM/PM_{10}, the permit must not allow for an even further relaxation of this limit up to 0.045 lb/MMBtu. This upper bound limit is wholly unjustified as BACT. Clearly, if Deseret obtains stack test data indicating that the total PM/PM_{10} BACT limit cannot reasonably be complied with, EPA can propose a revised total PM_{10} limit at a later time. Such a revised limit must be subject to public review and opportunity for comment.

[44] See April 7, 2006 email from Mike Owens, EPA Region 8, to Ed Thatcher, Deseret.

However, until such time, the evidence provided by EPA overwhelmingly indicates that the proposed total PM/PM_{10} BACT limit is too high.

The draft permit also fails to address BACT requirements when Deseret is using "run-of-mine" coal either in lieu of waste coal, or as a blend with waste coal, from the Deserado mine. (As allowed by Condition III.E.2.c. of the draft permit). As indicated by EPA in correspondence to Deseret, BACT needs to be met "for the entire range of operating conditions."[45] Yet, EPA did not provide any review of BACT or propose any emission limits to address BACT when the Bonanza WCFU is burning the much higher quality coal either wholly or in part. As discussed above, such a BACT limit must be imposed on a 24-hour average basis to ensure the maximum degree of PM emission reduction is required when 100% "run-of-mine" coal is being burned.

EPA Failed to Evaluate and Impose a BACT Limit for Visible Emissions

The BACT analysis for the Bonanza WCFU must also include a visible emission limit reflective of BACT for the source. The definition of BACT at 40 C.F.R. §52.21(b)(12) specifically indicates that BACT includes a "visible emission limitation." In the Statement of Basis, EPA indicated that, because EPA is proposing use of a PM continuous emission monitoring system (CEMS), "EPA does not consider it necessary to also propose an opacity limit as part of BACT for total filterable particulate." Statement of Basis at 47. EPA's reasoning is flawed for several reasons.

First and foremost, the definition of BACT in the Clean Air Act and associated federal regulations specifically mandate that BACT include a visible emission limitation. There are no exemptions provided for in the statutory or regulatory definition. Thus, EPA is without legal authority to decide not to impose an opacity limit because it is requiring PM CEMS for the PM limit. Second, the PM CEMs will only measure filterable particulate matter, while opacity measures all particulate matter that may block the transmission of light exiting the stack including condensable particulate matter. While compliance with the total particulate matter limit must be demonstrated on a rolling 30-day average basis at the Bonanza WCFU (Condition III.D.1.a. of the draft permit), this compliance determination will be based on a once-per-year stack test of the total PM emission rate (Condition III.I.4.b of the draft permit) . An opacity limit that can be continuously monitored will thus provide a much needed additional assurance that the total particulate matter emission limits are being complied with continuously. Further, a limitation on visible emissions serves as an indicator of proper operation and maintenance of all pollution control equipment. Last, compliance with both the filterable and total PM/PM_{10} limits is based on a rolling 30-day average basis, whereas compliance with opacity BACT limits are based on a six-minute averaging time. Thus, the 30-day rolling average filterable PM limit measured with CEMS is not an adequate replacement for a six-minute average opacity BACT limit.

With a fabric filter baghouse for PM_{10} control, an opacity BACT limit should be at least 10%. Indeed, the recently permitted Sevier CFB power plant in Utah is subject to

[45] See April 7, 2006 email from Mike Owens, EPA Region 8, to Ed Thatcher, Deseret.

a 10% visible emissions limit.[46] The River Hill Power Company proposed CFB power plant in Pennsylvania is also subject to a 10% opacity limit.[47] Similarly, the Gascoyne CFB facility will also be subject to a 10% opacity BACT limit.[48] Also noteworthy is the permit for the Longview power plant in West Virginia, which will utilize a pulverized coal boiler. This permit requires both PM CEMS to ensure compliance with its PM BACT limit *and* imposes a 10% opacity BACT limit.[49] Thus, EPA must include an evaluation of opacity BACT in its Statement of Basis and must impose a visible emission limit on the Bonanza WCFU that reflects the maximum degree of reduction achievable. Further, to ensure compliance on a continuous basis, a continuous opacity monitoring system (COMS) must be required.

5. THE BACT LIMITS MUST BE MET ON A CONTINOUS BASIS AND MEET ENFORCEABILITY CRITERIA

All BACT limits must be met on a continuous basis and must meet enforceability criteria, but the draft Bonanza WCFU permit does not adequately address EPA requirements for include such provisions. Specifically, as discussed in EPA's October 1990 Draft New Source Review Workshop Manual, "BACT emission limits or conditions must be met on a continual basis at all levels of operation (e.g., limits written in lb/MMBtu or percent reduction achieved), demonstrate protection of short term ambient standards (limits written in pounds per hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements)." (NSR Workshop Manual at B.56). EPA did not propose BACT limits consistent with this criteria.

With respect to all of the emission limits, there must be pound per hour emission caps established, in addition to lb/MMBtu limits, that must be reflective of BACT and consistent with what is modeled to show compliance with the NAAQS, PSD increments, and air quality related values. The October 1990 Draft NSR Workshop Manual indicates that it is best to express emission limits in two different ways, "with one value serving as an emissions cap (e.g., lb/hr) and the other ensuring continuous compliance at any operating capacity (e.g., lb/MMBtu)." See NSR Workshop Manual at H.5.. See also IN RE Steel Dynamics, Inc., PSD Appeal Nos. 99-4 & 99-5, Decided June 22, 2000, at 220-225. EPA only proposed BACT limits in terms of lb/MMBtu, and EPA did not evaluate or propose BACT limits in terms of lb/hr. While EPA did propose lb/hr "modeling limits" for SO_2 and total PM_{10} (Section G. of the draft permit), these modeling limits are not reflective of BACT for the Bonanza WCFU. Indeed, at full heat input capacity, the 3-hour average 872 lb/hr SO_2 modeling limit is equivalent to 0.6 lb/MMBtu, which would be only 87% SO_2 removal from worst case uncontrolled SO_2 emissions. The 24-hour total PM_{10} modeling limit of 75.4 lb/hr is equivalent to 0.052 lb/MMBtu at full heat

[46] See October 12, 2004 Approval Order for Sevier Power Company, Condition 12, at 10 (Attachment 10).
[47] See July 21, 2005 River Hill Permit, Condition I., #005, at 17, attached to September 28, 2005 email from Don Shepherd, National Park Service, to Hans Buenning, EPA Region 8.
[48] See Air Pollution Control Permit to Construct for Gascoyne, Condition II.A. 3), at 8 (Attachment 18).
[49] See March 2, 2004 Permit to Construct for Longview Power, Conditions A.8. and A.18., at 4, 9. (Attachment 16).

input capacity - which is greater than the maximum level EPA has proposed the total PM_{10} limit could be raised to. Thus, these modeling limits clearly do not reflect BACT for these pollutants. EPA also failed to propose BACT limits in terms of lb/hr for NO_x, CO, or H_2SO_4.

Further, the averaging time of the BACT emission limits must be "of a short-term nature" and must be consistent with the averaging time of the short term NAAQS and PSD increments, including a 24-hour averaging time for PM_{10} limits, an 8-hour averaging time for CO limits, and an 8-hour averaging time for VOC limits, as well as the 24-hour averaging time for the pollutants modeled in the visibility modeling.[50] Yet, EPA's proposed lb/MMBtu BACT limits for SO_2, NO_x, CO, and PM_{10} for the Bonanza WCFU are all based on rolling 30-day averages. As stated above, while EPA has proposed short term average emission limits for SO_2 and PM_{10} as modeling limits, these limits are not reflective of BACT for these pollutants.

The EPA's Statement of Basis explains that the lb/hr emission rates used in the modeling analyses reflect short term emission peaks from startups. Statement of Basis at 135. EPA also admitted that the proposed BACT limits for SO_2 and PM_{10} do not adequately limit short term emissions for compliance with the NAAQS and PSD increments because the BACT limits are based on 30-day rolling averages. Statement of Basis at 136. Yet, as acknowledged by EPA in the Statement of Basis, BACT emission limits must be met on a continuous basis, and there are to be no exemptions for startup and shutdown. Statement of Basis at 23. In particular, EPA noted that the October 1990 draft New Source Review Workshop Manual states (at page B.56) "BACT emission limits or conditions must be met on a continual basis *at all levels of operation.*" [Emphasis added.] *Id.* Yet, EPA's proposed BACT limits violate these principles and essentially provide for startup and shutdown exemptions from BACT by providing such long averaging times for the BACT emission limits.

EPA's failure to proposed shorter averaging time emission limits reflective of BACT is also inconsistent with recently issued permits for coal-fired power plants. For example, the Roundup power plant permit issued by the state of Montana required 24-hour average BACT limits for NO_x and SO_2, and also a 1-hour BACT limit for SO_2. The Sevier power plant permit issued by the state of Utah includes rolling 24-hour average BACT limits for SO_2, NO_x, PM_{10}, and H_2SO_4. The Longview power plant permit issued by the state of West Virginia has a 3-hour average SO_2 BACT limit, 24-hour average NO_x and SO_2 BACT limits, a 6-hour average PM_{10} BACT limit and a 3-hour average H_2SO_4 BACT limit. All of these permits are attached to this letter.

For all of the above reasons, EPA must revise its proposed BACT limits for the Bonanza WCFU to require shorter averaging times consistent with the NAAQS, PSD increments, and air quality related values standards and to also set lb/hr emission limits reflective of BACT.

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[50] See U.S. EPA, New Source Review Workshop Manual, October 1990 Draft, at H.5.

The permit must also specify appropriate compliance methods and recordkeeping requirements to show compliance with these emission limits. As discussed in the NSR Workshop Manual, "the construction permit should state how compliance with each limitation will be determined." (See NSR Workshop Manual at H.6.). The test methods must provide for continuous compliance where feasible. When compliance with BACT emission limits is determined over a 30-day averaging period – even if monitored with continuous emission monitoring systems, this does not ensure continuous compliance. Thus, as discussed above, BACT limits must be set for shorter averaging times, with compliance being monitored by continuous emission monitoring systems as proposed by EPA for SO_2, NO_x, and PM.

The draft permit for the Bonanza WCFU also lacks proper recordkeeping for some of the conditions of the permit. First, EPA must require Deseret to maintain records of all weekly Method 22 visible emissions evaluations of the unenclosed coal and limestone stockpiles required by Condition III.F.3. of the draft permit, in addition to maintaining records of all Method 9 opacity observations (per Condition III.I.8.c. of the draft permit). Second, regarding the monitoring of coal quality and sulfur content, EPA must require that heat content and sulfur content be tested and recorded on a daily basis for <u>all</u> coal used (i.e., washed or "run-of-mine" coal used during "emergencies" or in whole or blended in part during other times). This is necessary for comparison to a percent SO_2 removal requirement which we contend is necessary to ensure BACT is met over the wide variety of coal quality and sulfur content that will be used in the Bonanza WCFU.

6. EPA MUST PRESENT ITS ADJUSTMENTS TO DESERET'S MODELING ANALYSIS AND PROVIDE OPPORTUNITY TO COMMENT ON THE RESULTS

In its Statement of Basis, EPA indicated that Deseret improperly determined the maximum short term SO_2 emission rates expected from the Bonanza WCFU that were used in the modeling analyses. Statement of Basis at 135. EPA was apparently able to re-calculate worst case short term SO_2 emission rates based on data provided by Deseret, and found"[w]hen the higher emissions values are used as input for dispersion models, it still appears to EPA that the NAAQS and PSD Class I and II increments would not be exceeded." *Id.* However, EPA did not provide the results of its dispersion modeling analysis with the higher worst case short term SO_2 *emission limits* to the public for review and comment. EPA's revised 3-hour average SO_2 emission rate is almost six times greater than the 3-hour SO_2 emission rate modeled in Deseret's analyses, and the 24-hour average SO_2 emissions rate is close to 40% higher than what Deseret modeled. It is important to note that Deseret accepted EPA's revised short term SO_2 emission rates as an amendment to its PSD permit application.[51] These increased emission rates should have been taken into account in estimating the significant impact area of the Bonanza WCFU (which in turn would be used to determine which sources should have been included in cumulative NAAQS and increment analyses), and also in determining whether preconstruction monitoring and/or cumulative PSD increment analyses should

[51] November 3, 2005 email from Ed Thatcher, Deseret, to Mike Owens, EPA Region 8.

have been done. Further, it is not clear whether EPA determined that, cumulatively with other sources in the region, the NAAQS and PSD Class I and II increments would not be exceeded with EPA's recalculated worst case SO2 emission rates. Thus, EPA must present its revised modeling so the public can understand the true scope of short term average SO_2 impacts from the Bonanza WCFU and so that the public can ensure all CAA requirements will be complied with.

7. DESERET'S CUMULATIVE SO_2 NAAQS/INCREMENT ANALYSIS IS FLAWED

Deseret's cumulative SO_2 NAAQS and Class II PSD increment analysis is flawed because the 2002 SO_2 emission rate modeled for Bonanza Unit 1 is much lower than the peak short term SO_2 emission rate for this unit in 2002. Specifically, Deseret assumed an SO_2 emission rate, purportedly based on 2002 actual emissions, of 56.30 grams per second (g/s).[52] However, a review of the 2002 SO_2 emission data for Bonanza Unit 1 on EPA's Clean Air Market Database indicates that the maximum three-hour average SO_2 emission rate was 126 g/s (1000 lb/hr) and the maximum 24-hour average SO_2 emission rate was 115.9 g/s (920 lb/hr). Thus, Deseret greatly underestimated Bonanza Unit 1's impacts on the short term average SO_2 NAAQS and increment. Consequently, the NAAQS and increment analysis must be revised to model the highest 3-hour and 24-hour average emission rate of Bonanza Unit 1, as well as to model the EPA adjusted worst case 3-hour and 24-hour average SO_2 emission rates expected from the Bonanza WCFU. Further, the peak 3-hour and 24-hour SO_2 emission rates of Bonanza Unit 1 must be used in the cumulative Class I SO_2 increment modeling that is required, as discussed further below.

8. IT APPEARS DESERET SHOULD HAVE CONDUCTED PREAPPLICATION SO_2 MONITORING

It appears that Deseret was improperly exempted from one year of preconstruction ambient monitoring for SO_2. Although the PSD permit application shows that the SO_2 impacts from the Bonanza WCFU would be less than the monitoring significance levels, this modeling was based on Deseret's flawed approach of estimating worst case short term emission rates. As discussed above, EPA re-calculated maximum short term SO_2 emission rates but did not present the results of its revised modeling analyses. Considering that the emissions rate is all that would be changed in the revised modeling, one can simply adjust the results proportionately based on the EPA's revised emission rate as compared to Deseret's modeled SO_2 emission rate.

Deseret's worst case SO_2 emission rates modeled was 146.99 lb/hr. Statement of Basis at 135. EPA's recalculated worst case 24-hour average SO_2 emission rate was 201.9 lb/hr. *Id.* Multiplying Deseret's original 24-hour maximum near field concentration modeled of 10.8 ug/m3 (as provided in the Statement of Basis at 128) by

[52] November 2004 Dispersion Modeling, Deposition and Visibility Analysis for Deseret Generation and Transmission Cooperative's Proposed Bonanza Site 110 MW Waste Coal-Fired Unit, prepared by Meteorological Solutions, Inc., at 3-19.

the ratio of the revised worst case short term emission rate to the originally modeled worst case SO_2 emission rate results in a maximum 24-hour average SO_2 concentration of 14.8 ug/m3. This exceeds the 24-hour SO_2 monitoring significance level of 13 ug/m3. Thus, it appears that Deseret should have conducted one year of preapplication monitoring for SO_2. Consequently, EPA must delay issuing the permit until this data is collected.

9. DESERET FAILED TO PROVIDE ANY CUMULATIVE PSD INCREMENT ANALYSIS FOR ANY CLASS I AREA (OR FOR ANY COLORADO CLASS I AREAS)

Deseret failed to provide any cumulative PSD increment analysis for any affected Class I area in its permit application for the Bonanza WCFU. Neither Deseret's PSD permit application or EPA's Statement of Basis explains why cumulative increment analyses were not completed for Class I areas. The PSD permitting regulations mandate that no PSD permit can be issued unless the source demonstrates that it will not cause *or contribute to* a violation of any PSD increment. 40 C.F.R. §52.21(k)(2). Since Deseret has not made that demonstration, EPA cannot issue the permit.

One possible reason that Deseret did not perform any cumulative Class I PSD increment analyses might be because Deseret considers the impacts of the Bonanza WCFU to be less than significance levels.[53] However, there are no Class I area significance levels authorized in any federal regulation. While EPA proposed use of such Class I significant impact levels in July of 1996[54], EPA never finalized promulgation of those significant impact levels. Thus, until EPA adopts significant impact levels for Class I increments, *any* impact must warrant a cumulative analysis.

Moreover, even if use of proposed but never finalized significant impact levels were appropriate to exempt the Bonanza WCFU from a cumulative increment analysis in affected Class I areas, cumulative SO2 increment analyses would be required because the SO_2 impacts of the Bonanza WCFU would be greater than the proposed Class I significant impact levels for SO_2 in several Class I areas as follows:

First, Deseret's own modeling showed that its impact on the Colorado portion of Dinosaur National Monument would be greater than the SO_2 3-hour and 24-hour average proposed significant impact levels and greater than the 24-hour average Class I proposed significant impact level in Colorado National Monument.[55] Colorado's regulations mandate that Dinosaur National Monument and Colorado National Monument, although Class II areas, will be subject to the more stringent Class I increments for SO_2. (Colorado

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[53] See Class I area impact tables on pages 4-21 through 4-28 of November 2004 Dispersion Modeling, Deposition and Visibility Analysis for Deseret Generation and Transmission Cooperative's Proposed Bonanza Site 110 MW Waste Coal-Fired Unit, prepared by Meteorological Solutions, Inc., which identify the Bonanza WCFU's impact at each Class I area in terms of "Percent of EPA Class I Significance Levels."

[54] 61 Fed.Reg. 38291-38293 (July 23, 1996).

[55] November 2004 Dispersion Modeling, Deposition and Visibility Analysis for Deseret Generation and Transmission Cooperative's Proposed Bonanza Site 110 MW Waste Coal-Fired Unit, prepared by Meteorological Solutions, Inc., at 4-23, 4-24, and 4-30.

Regulation 3, Part B, Section VIII.B.1.b.). Thus, Deseret should have been required to perform a cumulative increment analysis for Dinosaur National Monument and Colorado National Monument.

Further, Deseret's analysis of the Bonanza WCFU's impacts on short term average SO_2 concentrations in Class I areas was flawed because, as noted by EPA, Deseret underestimated worst case short term SO_2 emission rates from the Bonanza WCFU. Statement of Basis at 135. As discussed in the above comment regarding the monitoring significance threshold, the predicted SO_2 impacts on the Class I areas can be proportionately adjusted based on the EPA's revised SO_2 emission rates as compared to Deseret's modeled SO_2 emission rate. EPA re-calculated Bonanza's WCFU worst case 3-hour average SO_2 emission rate to be 872 lb/hr, which is almost six times as high as the 146.99 lb/hr SO_2 emission rate modeled by Deseret. *Id.* Proportionately adjusting the 3-hour average SO_2 impacts of the Bonanza WCFU using EPA's revised worst case 3-hour average emission rate shows that the Bonanza WCFU would have an impact greater than the 3-hour average proposed significant impact level for SO_2 for most of the Class I areas in the region. The following table shows the revised Class I area 3-hour average SO_2 impacts based on EPA's revised worst case emission rates for those Class I areas where the Bonanza WCFU would exceed the proposed Class I significant impact levels. Thus, even if it were appropriate to exempt a facility from a cumulative Class I increment analysis based on its impacts being less than the proposed significant impact levels, the Bonanza WCFU would not be exempt from performing cumulative analyses of impacts on the 3-hour average SO_2 increment at Arches National Park, Canyonlands National Park, Capitol Reef National Park, Colorado National Monument, the Colorado portion of Dinosaur National Monument, the Flat Tops Wilderness area, and the Mt Zirkel Wilderness Area.

Thus, Deseret must be required to conduct cumulative Class I increment analyses for the nearby Class I areas. EPA must not issue a PSD permit for the Bonanza WCFU without ensuring that the facility will not cause *or contribute* to a violation of any PSD increment. Further, the cumulative Class I increment analyses must include the PSD increment consuming emissions of all other sources that could be affecting air quality in those Class I areas. This would include all large sources of air pollution within 200 kilometers of each Class I area, such as nearby coal-fired power plants (e.g., the Bonanza Unit 1, Hunter, Huntington, and Intermountain power plants in Utah, and the Craig, Hayden and Nucla power plants in Colorado). In addition, Deseret must be required to model those facilities which have submitted complete PSD permit applications and/or which have received air quality permits but which have not yet constructed. This would include NEVCO's Sevier Power plant, Unit 3 of the Intermountain Power Plant, and Unit 4 of the Hunter Power plant, all to be located in Utah. Deseret must also include the existing and proposed oil and gas development occurring near the Class I areas that Bonanza will affect. Until complete and thorough Class I increment modeling analyses are completed, EPA cannot issue the permit because it will not know whether the facility will cause or contribute to a Class I increment violation.

Table 1: Revised Class I Area SO_2 Impacts of Bonanza WCFU with EPA's Adjusted Worst Case SO_2 Rate

Class I area	Year of Met Data	Adjusted Predicted SO_2 Concentration, ug/m3	Averaging time	Proposed Class I SIL	% of SIL
Arches National Park	1992	1.4	3-hr, high	1.0	140.6%
	1992	1.3	3-hr, 2nd high[a]	1.0	129.3%
	1996	1.6	3-hr, high	1.0	160.2%
	1996	1.4	3-hr, 2nd high	1.0	142.4%
	1999	1.4	3-hr, high	1.0	141.2%
	1999	1.1	3-hr, 2nd high	1.0	114.5%
Canyonlands National Park	1992	1.5	3-hr, high	1.0	150.7%
	1992	1.3	3-hr, 2nd high	1.0	134.7%
	1996	1.3	3-hr, high	1.0	125.2%
	1996	1.2	3-hr, 2nd high	1.0	115.7%
	1999	1.3	3-hr, high	1.0	131.1%
	1999	1.2	3-hr, 2nd high	1.0	119.2%
Capitol Reef National Park	1992	1.0	3-hr, high	1.0	104.4%
	1992	0.9	3-hr, 2nd high	1.0	94.3%
	1996	1.1	3-hr, high	1.0	106.8%
	1996	0.7	3-hr, 2nd high	1.0	72.4%
	1999	0.4	3-hr, high	1.0	35.2%
	1999	0.3	3-hr, 2nd high	1.0	30.6%
Colorado National Monument	1992	4.4	3-hr, high	1.0	439.6%
	1992	3.6	3-hr, 2nd high	1.0	364.2%
	1996	2.0	3-hr, high	1.0	195.2%
	1996	1.9	3-hr, 2nd high	1.0	191.6%
	1999	3.6	3-hr, high	1.0	355.9%
	1999	3.1	3-hr, 2nd high	1.0	312.0%
Dinosaur National Monument (Colo)	1992	12.6	3-hr, high	1.0	1263.6%
	1992	10.9	3-hr, 2nd high	1.0	1091.6%
	1996	11.5	3-hr, high	1.0	1150.9%
	1996	9.7	3-hr, 2nd high	1.0	972.9%
	1999	11.1	3-hr, high	1.0	1109.4%
	1999	10.1	3-hr, 2nd high	1.0	1014.4%
Flat Tops Wilderness Area	1992	2.0	3-hr, high	1.0	204.7%
	1992	2.0	3-hr, 2nd high	1.0	195.2%
	1996	2.1	3-hr, high	1.0	211.2%
	1996	1.8	3-hr, 2nd high	1.0	180.9%
	1999	1.6	3-hr, high	1.0	163.1%
	1999	1.6	3-hr, 2nd high	1.0	160.8%
Mt. Zirkel Wilderness Area	1992	1.8	3-hr, high	1.0	179.2%
	1992	1.5	3-hr, 2nd high	1.0	152.5%
	1996	1.0	3-hr, high	1.0	102.0%
	1996	0.9	3-hr, 2nd high	1.0	90.8%
	1999	0.9	3-hr, high	1.0	93.1%
	1999	0.8	3-hr, 2nd high	1.0	82.5%

[a]In determining whether a source's impact is greater than significant impact levels, the highest predicted concentration is used. See EPA's October 1990 Draft New Source Review Workshop Manual at C.16, C.26, and C.51. Because Deseret provided both the high and 2[nd] high predicted concentrations, we revised both values using EPA's revised 3-hour SO2 emission rate.

10. EPA MUST NOT ISSUE THE PSD PERMIT FOR THE BONANZA WCFU IN LIGHT OF THE PSD SO_2 INCREMENT VIOLATIONS OCCURRING AT CAPITOL REEF NATIONAL PARK

During the permit review and proceedings for the proposed Unit 3 of the Intermountain Power Plant located in Delta, Utah, the National Park Service conducted a Class I SO_2 increment analysis and determined that **existing** sources in Utah are causing violations of the 3-hour average Class I SO_2 increment in Capitol Reef National Park. Specifically, on March 25, 2004, the National Park Service submitted a letter to the Utah Division of Air Quality that provided, among other things, the Park Service's formal findings that the 3-hour average SO_2 increment was being violated by existing sources in Utah at Capitol Reef National Park.[56] In May of 2003, the Assistant Secretary for Fish and Wildlife and Parks submitted a letter and accompanying Technical Support Document reiterated that existing sources are causing violations of the 3-hour average SO_2 increment at Capitol Reef National Park.[57] Because the SO_2 emissions from the Bonanza WCFU will increase 3-hour average SO_2 concentrations in this Class I area – and at a level greater than the proposed Class I significance level - the Bonanza WCFU will contribute to the existing violations of the 3-hour average SO_2 increment. Federal law mandates that no permit can be issued for a new major source if it would cause *or contribute* to a violation of the PSD increments.

The federal prohibition on the issuance of a permit in this case of existing PSD increment violations are clear. Section 165(a)(3) of the Clean Air Act provides that no permit authorizing construction of a new source can be issued unless the owner or operator demonstrates that the emissions from such facility "will not cause, or contribute to, air pollution in excess of (A) maximum allowable increase or maximum allowable concentration for any pollutant. . . ." The maximum allowable increases, or "PSD increments," are standards not to be exceeded.[58] See §163(a) and (b). The statutory provision that a permit cannot be issued unless the source won't cause or contribute to an increment violation is incorporated into the federal PSD regulations at 40 C.F.R. §52.21(k)(2). In addition, EPA's longstanding contemporaneous interpretation of the statutory and regulatory provisions for the PSD increments clearly mandate that, in an area with existing PSD increment violations, the violations "must be entirely corrected before PSD sources which affect the area can be approved." (See 45 Fed.Reg. 52678, August 7, 1980).

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[56] National Park Service Comments on the Intermountain Power Agency Prevention of Significant Permit Application for the Addition of Unit 3 at its Intermountain Power Plant, March 2004, attached to its March 25, 2004 letter to Rick Sprott, Utah Division of Air Quality, at 5. (Attachment 20)

[57] National Park Service Supplemental Technical Comments on the Intermountain Power Agency Prevention of Significant Permit Application for the Addition of Unit 3 at its Intermountain Power Plant, May 2004, attached to its May 2004 letter from the Assistant Secretary for Fish and Wildlife and Parks to Rick Sprott, Utah Division of Air Quality, at 8-9. (Attachment 21.)

[58] §163(a) of the Clean Air Act provides that, except for annual average PSD increments, the increments can be exceeded only once per year. No exceedances of the annual average increments are allowed.

It is important to note that the March 25, 2004 National Park Service letter to the Utah Division of Air Quality erroneously claimed that, because Intermountain Power Plant Unit 3's impact on the SO_2 increment violations at Capitol Reef National Park was below the "significant impact level," the proposed new Unit 3 at the Intermountain Power Plant would not be considered to cause or contribute to the 3-hour average SO_2 increment violations. There is no legal or regulatory basis in Utah regulations or in the federal PSD regulations to consider a source's impact on an increment violation as insignificant. Further, this is contrary to EPA's interpretation of the law. EPA Region 8 stated in an April 12, 2002 letter to the North Dakota Department of Health that the use of significant impact levels to allow a PSD permit to be issued in the case of an area showing increment violations is not consistent with the intent of the Clean Air Act's PSD program. (See attached April 12, 2002 letter, Attachment 19). Indeed, EPA stated that, in the case of an area with existing increment violations, "any impact (not just one that is 'significant') on a receptor in a Class I area that shows a violation of the PSD increment would be considered to contribute to that increment violation. Furthermore. . .even if some of the impacts are relatively small they are still contributing to an existing problem."[59]

The Bonanza WCFU will have an impact on 3-hour average SO_2 concentrations in Capitol Reef National Park.[60] Further, when those impacts are adjusted proportionately based on EPA's adjusted worst case 3-hour average emission rate expected from the Bonanza WCFU, its impacts exceed the proposed Class I significant impact level at Capitol Reef National Park. (See Table 1 above). There is no question that the Bonanza WCFU will contribute to existing SO_2 increment violations at Capitol Reef National Park. Therefore, EPA is prohibited from issuing the PSD permit to the Bonanza WCFU until the SO_2 increment violations at Capitol Reef National Park are adequately addressed.

11. DESERET'S VISIBILITY MODELING IS FLAWED

Deseret's visibility modeling analysis of the Bonanza WCFU is flawed because Deseret failed to model maximum 24-hour average emissions of SO_2 and because Deseret failed to properly document why it was necessary or appropriate to rollback the relative humidity in the regional haze modeling to 95%. Consequently, the visibility modeling is flawed and likely underestimated the impacts of the Bonanza WCFU on visibility in nearby Class I areas.

As discussed above, EPA adjusted the worst case 24-hour SO_2 emission rate based on data from Deseret because Deseret's estimate of worst case SO_2 emissions did not properly include emissions from start-ups. See Statement of Basis at 135. With EPA's adjustment, the worst case 24-hour average SO_2 emission rate is 37% higher than the emission rate that was modeled in Deseret's visibility analysis. Thus, Deseret's

[59] Attachment to April 12, 2002 letter from Richard R. Long, EPA Region 8, to Terry L. O'Clair, North Dakota Department of Health, at 5. (Attachment 19.)
[60] See November 2004 Dispersion Modeling, Deposition and Visibility Analysis for Deseret Generation and Transmission Cooperative's Proposed Bonanza Site 110 MW Waste Coal-Fired Unit, prepared by Meteorological Solutions, Inc., at 4-23, 4-29, and 4-35.

visibility analysis underestimated visibility impacts in all affected Class I areas. Deseret must be required to re-model visibility impacts using the adjusted worst case 24-hour average SO_2 emission rate of 201.9 lb/hr and such modeling must be provided to the Federal Land Managers for review.

Deseret estimated visibility impacts using both a maximum relative humidity of 98%, consistent with the Federal Land Managers' guidance, and rolling back relative humidity to 95%.[61] However, the National Park Service indicated that any analysis rolling back relative humidity to 95% would have to be "well documented as to why it is appropriate to. . .roll back relative humidity to 95%. . . ."[62] Deseret did not provide any such documentation. Therefore the results of its visibility analysis capping relative humidity at 95% cannot be relied upon.

Based on the visibility modeling done by Deseret that is consistent with current guidance of the Federal Land Managers (i.e., capping relative humidity at 98%), the Bonanza WCFU will have an adverse impact on visibility (greater than a 5% change) at Arches and Capitol Reef National Parks.[63] This analysis must be redone with the EPA's worst case 24-hour average SO_2 emission rate and the results transmitted to the appropriate Federal Land Managers. Because the impacts on visibility will be greater using the higher SO_2 worst case 24-hour average emission rate, it appears the Bonanza WCFU will have an adverse visibility impact at some nearby Class I areas. EPA Region 8 must ensure that, in issuing a permit for the Bonanza WCFU, its actions are consistent with the intent of the PSD requirements of the Clean Air Act – specifically, whether its actions will preserve, protect, and enhance the air quality in nearby national parks and wilderness areas (i.e., pursuant to §160(1) of the Clean Air Act), and whether its actions will ensure that emissions from the Bonanza WCFU will not interfere with portions of State Implementation Plans aimed at preventing significant deterioration of air quality including preventing future visibility impairment (i.e., pursuant to §160(4) and 169(a)(1) of the Clean Air Act).

Thank you for considering our comments.

[61] *Id.* at 4-49.
[62] August 6, 2004 email from John Notar, National Park Service, to Ed Thatcher, EPA Region 8.
[63] November 2004 Dispersion Modeling, Deposition and Visibility Analysis for Deseret Generation and Transmission Cooperative's Proposed Bonanza Site 110 MW Waste Coal-Fired Unit, prepared by Meteorological Solutions, Inc., at 4-51.

Sincerely,

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<u>List of Attachments (all of which are on a CD accompanying this letter):</u>

1. "Coal-Related Greenhouse Gas Management Issues", National Coal Council, May 2003;
2. *Considering Alternatives: The Case for Limiting CO_2 Emissions from New Power Plants through New Source Review* by Gregory B. Foote;
3. Letter from Illinois Division of Air Pollution Control to Jim Schneider, Indeck-Elwood, LLC (March 8, 2003);
4. Letter from Illinois EPA Director to EPA Regional Administrator, Region V (March 19, 2003);
5. Letter from James A. Capp, Manager, Stationary Source Permitting Program, Georgia DNR, to D. Blake Wheatley, Assistant Vice President, Longleaf Energy Associates, LLC (March 6, 2002);
6. Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Corporation (Dec. 23, 2002);
7. Letter from New Mexico Environment Department to Larry Messinger, Mustang Energy Company (Aug. 29, 2003);
8. April 6, 2004 letter from Richard R. Long, EPA, to Rick Sprott, Utah Division of Air Quality regarding the Sevier Power Company Permit;
9. Western Governor's Association Technology Working Group's report on advanced clean coal technologies;
10. October 12, 2004 Sevier Power Company permit;
11. Utah Division of Air Quality New Source Plan Review for the Sevier Power Company, December 23, 2003;
12. December 18, 2002 letter from Richard R. Long, EPA Region 8, to Steve Welch, Montana Department of Environmental Quality on the Roundup permit;
13. October 29, 2001 permit for AES-Puerto Rico;
14. November 4, 2003 Memorandum from Don Shepherd to John Notar regarding the Sevier Power Plant;
15. July 21, 2003 Roundup power plant permit;
16. March 2, 2004 Longview power plant permit;
17. Bielawski, G.T., J.B. Rogan, and D.K. McDonald, How Low Can We Go?;
18. Air Pollution Control Permit to Construct for Gascoyne (PTC-05005);
19. EPA's April 12, 2002 letter to the North Dakota Department of Health;
20. National Park Service Comments on the Intermountain Power Agency Prevention of Significant Permit Application for the Addition of Unit 3 at its Intermountain Power Plant, March 2004, attached to its March 25, 2004 letter to Rick Sprott, Utah Division of Air Quality; and
21. National Park Service Supplemental Technical Comments on the Intermountain Power Agency Prevention of Significant Permit Application for the Addition of Unit 3 at its Intermountain Power Plant, May 2004, attached to its May 2004 letter from the Assistant Secretary for Fish and Wildlife and Parks to Rick Sprott, Utah Division of Air Quality.
22. U.S. EPA "New Source Review Workshop Manual" Draft October 1990.

Exhibit 3

RESPONSE TO PUBLIC COMMENTS

ON

Draft
Air Pollution Control
Prevention of Significant Deterioration (PSD)
Permit to Construct

Permit No. PSD-OU-0002-04.00

<u>Permittee</u>:
Deseret Power Electric Cooperative
10714 South Jordan Gateway
South Jordan, Utah 84095

<u>Permitted Facility</u>:
110-Megawatt Waste Coal Fired Unit
at Bonanza Power Plant

United States Environmental Protection Agency
Region 8
Air & Radiation Program
Denver, Colorado
August 30, 2007

B. COMMENTS AND RESPONSES

The descriptions of public comments below are a paraphrasing of the originally submitted comments. The full text of each public comment may be found in the Administrative Record for issuance of the WCFU permit, available at the same locations as the draft permit package was available (the Uintah County Clerk's office in Vernal, Utah, the Ute Indian Tribe office in Fort Duchesne, Utah, and the EPA Region 8 office in Denver, Colorado).

1. CARBON DIOXIDE/GREENHOUSE GAS EMISSIONS

Comment #1:

One group of commenters requested that EPA address carbon dioxide (CO_2) and other greenhouse gas (GHG) emissions from the proposed Deseret Bonanza WCFU. The commenters stated that the Clean Air Act requires EPA to do so in two ways.

Comment #1.a. First, the commenters believe EPA has a legal obligation to regulate CO_2 and other GHGs under the Clean Air Act and thus should set CO_2 emission limits in this permit.

Comment #1.b. Second, the commenters believe that EPA should consider emissions of CO_2 in its BACT analyses for other pollutants at the Bonanza WCFU.

In support, the commenters cited a U.S. Supreme Court case that was pending at the time, an Environmental Appeals Board decision, a draft EPA guidance document, and an article presenting a potential legal rationale for using PSD permits to limit CO_2 emissions.

Response #1:

Response #1.a. Disagree. EPA recognizes the importance of addressing the global challenge of climate change, and in light of the Supreme Court's decision in *Massachusetts v. EPA*, 127 S. Ct. 1438 (2007), the Agency is working diligently to develop an overall strategy for addressing the emissions of CO2 and other GHGs under the Clean Air Act. However, EPA does not currently have the authority to address the challenge of global climate change by imposing limitations on emissions of CO_2 and other greenhouse gases in PSD permits.

It is well established that "EPA lacks the authority to impose [PSD permit] limitations or other restrictions directly on the emission of unregulated pollutants." *North County Resource Recovery Assoc.*, 2 E.A.D. 229, 230 (EAB 1986). The Clean Air Act and EPA's regulations require PSD permits to contain emissions limitations for "each pollutant subject to regulation" under the Act. CAA § 165(a)(4); 40 C.F.R. § 52.21(b)(12). In defining those PSD permit requirements, EPA has historically interpreted the term "subject to regulation under the Act" to describe pollutants that are presently subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant. *See* 43 Fed. Reg. 26388, 26397 (June 19, 1978) (describing pollutants subject to BACT requirements); 61 Fed. Reg. 38250, 38309-10 (July 23, 1996) (listing pollutants subject to PSD review). In 2002, EPA codified this approach for implementing PSD by defining the term "regulated NSR pollutant" and clarifying that Best Available Control Technology is required "for each regulated NSR pollutant that [a major source] would have the potential to emit in significant amounts." 40 C.F.R. § 52.21(j)(2); 40 CFR 52.21(b)(50).

In defining a "regulated NSR pollutant," EPA identified such pollutants by referencing pollutants regulated in three principal program areas -- NAAQS pollutants, pollutants subject to a section 111 NSPS, and class I or II substance under title VI of the Act-- as well as any pollutant "that otherwise is subject to regulation under the Act." 40 CFR 52.21(b)(50)(i)-(iv). As used in this provision, EPA continues to interpret the phrase "subject to regulation under the Act" to refer to pollutants that are presently subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant. Because EPA has not established a NAAQS or NSPS for CO_2, classified CO_2 as a title VI substance, or otherwise regulated CO_2 under any other provision of the Act, CO_2 is not currently a "regulated NSR pollutant" as defined by EPA regulations.

Although the Supreme Court decided the case cited by commenters and held that CO_2 and other GHGs are air pollutants under the CAA, *see Massachusetts v. EPA*, 127 S. Ct. 1438 (2007), that decision does not require the Agency to set CO_2 emission limits in the PSD permit for the Deseret Bonanza WCFU. Notably, the Court did not hold that EPA was required to regulate CO_2 and other GHG emissions under Section 202, or any other section, of the Clean Air Act. Rather, the Court concluded that these emissions were "air pollutants" under the Act, and, therefore, EPA could regulate them under Section 202 (the provision at issue in the *Massachusetts* case), subject to certain Agency determinations pertaining to mobile sources.

EPA is currently exploring options for addressing GHG emissions in response to the Supreme Court decision. EPA is taking the first steps toward regulating GHG emissions from mobile sources, but the Agency has not yet issued regulations requiring control of CO_2 emissions under the Act generally or the PSD program specifically. Accordingly, EPA cannot include emissions limitations for CO_2 (or other GHGs that are not otherwise regulated NSR pollutants) in the Deseret PSD permit because it has long been established that "EPA lacks the authority to impose [PSD permit] limitations or other restrictions directly on the emission of unregulated pollutants." *North County*, 2 E.A.D. at 230. At this time, we believe that any action EPA might consider taking with respect to regulation of CO_2 or other GHGs in PSD permits or other contexts should be addressed through notice and comment rulemaking, allowing for a process which is public and transparent and based on the best available science.

Response #1.b: Disagree. EPA recognizes the importance of addressing the global challenge of climate change, and in light of the Supreme Court's decision in *Massachusetts v. EPA*, 127 S. Ct. 1438 (2007), the Agency is working diligently to develop an overall strategy for addressing the emissions of CO2 and other GHGs under the Clean Air Act. Nevertheless, with regard to the present permitting decision, the