Air Pollution Control
Title V Permit to Operate
Draft Permit No. V-UO-000004-00.00
Draft Initial Part 71 Permit

Deseret Power Electric Cooperative
Bonanza Power Plant
Uintah and Ouray Reservation
Uintah County, Utah

Statement of Basis

FACILITY INFORMATION

1. Location

The Bonanza plant, owned and operated by Deseret Power Electric Cooperative ("Deseret"), is located in Uintah County in northeastern Utah, in Indian country within the Uintah and Ouray Indian Reservation. The exact location is latitude 40° 4.94' N, longitude 109° 17.48' W, 7.5 miles northwest of Bonanza and 28 miles southeast of Vernal. The plant mailing address is:

Deseret Power Electric Cooperative
12500 East 25500 South
Vernal, UT 84078-8525

Driving directions to the facility (from Vernal, Utah) are:

- Take highway 40 south, about 4 to 5 miles.
- Turn right onto State Road 45, then go about 25 miles.
- Turn at entrance sign for Bonanza plant.

2. Company contacts

Facility contact: Eric Olsen
Deseret Power Electric Cooperative
12500 East 25500 South
Vernal, UT 84078-8525
435-781-5706

Responsible official: Gene Grindle, Plant Manager
Deseret Power Electric Cooperative
12500 East 25500 South
Vernal, UT 84078-8525
435-781-5701

3. Process Description

The Bonanza plant is a 500 megawatt (estimated) coal-fired electric utility consisting of a single dry bottom, wall-fired main boiler, rated at about 4,578 million Btu per hour heat input capacity. Air pollutant emissions are virtually all from the main boiler tall stack (approximately 600 feet tall). Washed bituminous coal is supplied from the nearby Deserado mine. See Attachment 1 of the draft Part 71 operating permit for a detailed process description.

4. Permitting History

The Bonanza plant, originally referred to in the late 1970's as the Moon Lake Power Plant Project Units 1 and 2, was issued an initial PSD permit-to-construct by the U.S. EPA Region 8 office on February 4, 1981. The permit was for construction of two 400-megawatt units. Only one unit was actually constructed, in the early 1980's. It commenced commercial operation in 1985.

On December 21, 1995, Deseret Power submitted a Part 70 permit application to the State of Utah. On October 2, 1997, the State sent a proposed 40 CFR Part 70 operating permit (including acid rain provisions) to EPA Region 8 for 45-day review. Later in October of 1997, EPA Region 8 orally informed the State that EPA considered the plant to be in Federal permitting jurisdiction rather than State jurisdiction. By letter to EPA dated December 15, 1997, the State agreed to withdraw its proposed Part 70 permit.

EPA Region 8 issued a Federal acid rain permit for Bonanza plant, which became final on December 29, 1997.

By letter to Deseret Power dated March 30, 1999, EPA Region 8 notified Deseret that EPA is the Title V permitting authority in Indian country on the Uintah & Ouray Indian Reservation and requested Deseret to submit a Federal Title V (Part 71) permit application for the Bonanza plant by March 22, 2000. By letter to Deseret Power dated September 22, 1999, EPA Region 8 notified Deseret that, since the plant is also under Federal permitting jurisdiction for New Source Review, it would be necessary for EPA to update and re-issue the 1981 Federal PSD permit. EPA Region 8 issued the updated Federal PSD permit on February 2, 2001. Meanwhile, in March 2000, Deseret submitted a Part 71 permit application to EPA. Revisions to the March 2000 application and other additional information items were submitted on:

- November 14, 2001 (to add a small "grasshopper" conveyor system at the end of the regular sludge conveyor system)

- January 29, 2002 (to submit standard EPA forms for renewal of acid rain permit – Acid Rain Permit Application form and Phase II NO_x Compliance Plan form)

- February 13, 2002 (updated EXCEL spreadsheets on emission inventory calculations, primarily to account for change to low sulfur fuel for the auxiliary boiler)

- February 26, 2002 (submittal of copy of fugitive dust control plan, statement of non-applicability of 40 CFR Part 68, and statement of potential future applicability of 40 CFR 60 Subpart Y, due to potential future operation of an on-site coal crusher)

- May 30, 2002 (statement of applicability of 40 CFR 82 Subpart H for halon-containing fire protection system, revision to estimate of potential-to-emit for hydrochloric acid and hydrofluoric acid, and revisions to sizes of gasoline and diesel fuel storage tanks)

In August of 2002, EPA Region 8 made available for public comment a draft Part 71 operating permit for Bonanza plant. EPA received comments from Deseret Power and from the National Park Service (NPS). The comments from Deseret Power were to request that certain factual errors in the permit package be corrected, and to question the scope of applicability of NSPS Subpart Y. The comment from the NPS was that PSD applicability for the ruggedized rotor project constructed in June of 2000 should be investigated, as it appeared to the NPS that the project should have gone through PSD review as a major modification. EPA's responses to the concerns from Deseret and from the NPS may be found later in this Statement of Basis and related Appendix.

On February 6, 2012, EPA requested that Deseret Power submit an updated Part 71 permit application. On April 3, 2012, Deseret Power submitted the updated application, which Deseret Power further amended on March 13 and 18, 2013, on January 27, 2014, and on April 3, 9, 10 and 15, 2014. On November 14, 2012, EPA wrote to Deseret Power requesting a meeting with Deseret Power to further discuss the ruggedized rotor project. On December 4, 2012, Deseret Power and EPA discussed the matter via phone. On January 30, 2014, EPA met with Deseret to discuss various permit issues. A copy of the November 14, 2012 letter, a record of the December 4, 2012 telephone conversation, and a record of the January 30, 2014 meeting may be found in the Permitting Record for this Part 71 permit action.

The Deseret Title V permit application has been pending beyond the 18 month Clean Air Act deadline for EPA to issue or deny the permit.[1] WildEarth Guardians filed suit in federal District Court on December 23, 2013 (WildEarth Guardians v. McCarthy, Civ. No. 1:13-cv-03457-JLK (D. Colo. 2013)), alleging that EPA has failed to take action on an application for an Operating Permit under Title V of the Clean Air Act ("CAA"), [2] and EPA's implementing regulations at 40 C.F.R. part 71, for the Deseret Bonanza coal-fired power plant in the timeframe required under 42 U.S.C. § 7661b(c). The proposed Consent Decree, for which a public notice and opportunity for comment will soon be published in the Federal Register, requires that EPA issue a final Title V permit decision for the Deseret Bonanza Power Plant on or before August 29, 2014, in accordance with 40 C.F.R. 71.11(i), which regulation also addresses the effective date and possible administrative appeal of the final permit decision.

EPA has now updated the applicable requirements in the draft Part 71 permit.. The updated draft Part 71 operating permit incorporates applicable requirements from:

→ 40 CFR 52.21 (Federal PSD permit of February 2, 2001);

→ 40 CFR Part 60 (NSPS), Subparts A, Da, Y and Appendices A, B and F;

→ 40 CFR Part 63 (NESHAP), Subparts A, ZZZZ and UUUUU;

→ 40 CFR part 64 (Compliance Assurance Monitoring rule);

→ 40 CFR Part 71 (Federal Operating Permits Program);

→ 40 CFR Parts 72 through 78 (Federal Acid Rain Program); ane

→ 40 CFR Part 82 (Stratospheric Ozone and Climate Protection), Subparts F and H.

5. Potential-to-emit

Virtually all of Bonanza plant's emissions come from the main boiler. The potential-to-emit for the main boiler, in tons per year, as listed in forms "PTE" and "EMISS" and section D of the Part 71 operating permit application, amended by email to EPA on March 13, 2013, is as follows:

Pollutant	Potential-to-emit (tons per year)
CO	503
SO_2	1,968
NO_x	9,228
PM_{10}	574
HAPs	68
VOC	70

6. List of all units and emission-generating activities

In the Part 71 permit application for the Bonanza plant, Deseret Power provided the information shown in Tables 1 and 2 below. Table 1 lists the only significant emission unit (the main boiler) and its air pollution control equipment. Insignificant activities/emitting units are listed separately in Table 2.

Applicable requirements for the main boiler in Table 1 are listed in section II.A of the draft Part 71 operating permit. Applicable requirements for insignificant activities/emit-ting units in Table 2 are listed in section II.B. of the draft operating permit. Insignificant activities/emitting units in Table 2 that have no applicable requirements are indicated with an asterisk.

Part 71 allows sources to separately list in the permit application units or activities that qualify as "insignificant" based on potential emissions below 2 tons/year for all regulated pollutants that are not listed as hazardous air pollutants ("HAP") under Section112(b) and below 1,000 lbs/year or the de minimis level established under Section 112(g), whichever is lower, for HAPs. However, the application may not omit information needed to determine the applicability of, or to impose, any applicable requirement, or to calculate the emissions fee. Units or activities that qualify as "insignificant" for the purposes of the Part 71 application are in no way exempt from applicable requirements or any requirements of the Part 71 permit.

Table 1
Significant Emission Units

Emission Unit Id.	Description	Control Equipment
1-1	BOILER: Foster-Wheeler steam generator; heat input capacity of 4,578 MMBtu/hr; dry bottom wall-fired.on bituminous coal; uses diesel or natural gas during startup, shutdown, upsets and flame stabilization. Constructed in 1984. Exhausts through main plant stack.	low-NOx burners; baghouse (10,800 bags); wet limestone FGD scrubber (3 modules)

Table 2
Insignificant Activities/Emitting Units

Activity/ Emission Unit ID	Description	Applicable Permit Condition
1-2	AUXILIARY BOILER * (184 MMBtu/hr, pre-1984, fired on fuel oil or natural gas)	None
1-3	EMERGENCY DIESEL GENERATOR (750 KW, 1,220 HP, fired on fuel oil, started up in 2013)	II.A.4.(b)
1-4	EMERGENCY DIESEL FIRE PUMP (2.83 MMBtu/hr, 498 HP, fired on fuel oil, started up in mid-1980's)	II.A.4.(a)
1-5	CONSTRUCTION HEATERS * (12.81 MMBtu/hr each, fired on propane)	None
DC-1	COAL TERMINAL BUILDING (coal distribution facility connecting conveyors 1, 2 & 8; equipped with fabric filter dust collector)	II.B.1.(a), II.B.2
DC-2	COAL SILO (silo for storing and handling coal; equipped with baghouse)	II.B.1.(a), II.B.2
DC-3	COAL SILO RECLAIM/TRANSFER (coal handling area; equipped with fabric filter dust collector)	II.B.1.(a), II.B.2
DC-4	COAL CRUSHING BUILDING (receives coal from silo and reclaim; equipped with fabric filter dust collector)	II.B.1.(a), II.B.2
DC-5	COAL BUNKERS (coal storage bunkers that feed pulverizers; equipped with fabric filter dust collector)	II.B.1.(a), II.B.2
LDC-1	LIMESTONE RECEIVING HOPPER (hopper to transfer limestone to the limestone conveyor; equipped with fabric filter dust collector)	II.B.1.(a)
LDC-2	LIMESTONE STORAGE BUNKERS (limestone storage bunkers for feeding scrubber; equipped with fabric filter dust collector)	II.B.1.(a)
none	FLY ASH SILO * (stores fly ash prior to loading on landfill conveyor; equipped with fabric filter dust collector)	None

Activity/ Emission Unit ID	Description	Applicable Permit Condition
none	COAL TRACK HOPPER FOR BOTTOM-DUMP COAL (below-track coal car unloading hopper; equipped with water sprays)	II.B.1.(b), II.B.2
none	COAL PILE (coal storage pile, maximum 22 acres, consisting of a long-term storage area and active/reclaim area (maximum 11 acres); surfactant sealant used as needed for dust control at long-term storage area)	II.B.1.(c), II.B.1.(f)
none	COAL CONVEYORS 1, 2 & 8 (all covered; conveyors 1 and 8 equipped with water sprays)	II.B.1.(a), II.B.2
none	COAL CONVEYORS 3a, 3b, 4a & 4b (covered; coal transfer from storage to plant)	II.B.1.(a), II.B.2
none	LIMESTONE LONG-TERM STORAGE PILE (surfactant sealant used as needed for dust control)	II.B.1.(d), II.B.1.(f)
none	LIMESTONE CONVEYOR (covered; transfers limestone from storage area to scrubber)	II.B.1.(a)
none	ASH/SLUDGE LANDFILL CONVEYOR * (covered conveyor from sludge building to landfill; includes "grasshopper" conveyor system, consisting of four uncovered conveyors, at end of regular sludge conveyor system)	None
none	ASH/SLUDGE LANDFILL DISCHARGE AREA (active discharge area for ash and sludge; water sprays as necessary for dust control)	II.B.1.(e)
none	ASH/SLUDGE LANDFILL * (stabilized and inactive)	None
none	ACCESS/HAUL ROADS (partially paved road from boiler building to landfill; road from SFC discharge to bottom ash landfill; water sprays or chemical treatment as necessary for dust control)	II.B.1.(g), II.B.1.(h)
none	PERIMETER ROAD (unpaved road around the perimeter fence; water sprays or chemical treatment as necessary for dust control)	II.B.1.(g), II.B.1.(h)
Tank #1, west	#2 DIESEL FUEL OIL STORAGE TANK #1 * (288,000 gallon capacity)	None

Activity/ Emission Unit ID	Description	Applicable Permit Condition
Tank #2, east	#2 DIESEL FUEL OIL STORAGE TANK #2 * (288,000 gallon capacity)	None
none	ABOVE-GROUND GASOLINE STORAGE TANK * (10,000 gallon capacity)	None
none	ABOVE-GROUND DIESEL STORAGE TANK * (20,000 gallon capacity)	None
none	VEHICLE REFUELING EQUIPMENT FOR DIESEL AND GASOLINE *	None
none	TRUCK-MOUNTED VACUUM SYSTEM ("GUZZLER") * (mobile truck mounted vacuum equipped with particulate filter to clean up spilled material such as ash)	None
none	MISCELLANEOUS ABRASIVE BLASTING * (abrasive blasting of parts and equipment inside the boiler baghouse)	None
none	WATER TREATMENT AND ASSOCIATED CHEMICAL STORAGE * (areas for equipment and chemicals to treat water used on site)	None
none	BOTTOM ASH LANDFILL *	None

* = no applicable requirements.

UINTAH AND OURAY INDIAN RESERVATION

1. **Indian country:** The Bonanza plant is located in Indian country on the Uintah and Ouray Indian Reservation and is considered by EPA to be in Federal jurisdiction.

2. **Local air quality and attainment status:** The Uintah and Ouray Indian Reservation is designated as either attainment or "unclassifiable" for the national ambient air quality standards for all criteria pollutants. An area is unclassifiable when there are insufficient monitoring data. An ambient air monitoring network is maintained on the Reservation to collect ozone, NO_x and $PM_{2.5}$ data at the Myton station, as well as ozone and NO_x data at the Whiterocks station. In addition, two other ambient monitoring stations, which collect ozone, NO_x and $PM_{2.5}$ data, are operated on the Reservation at the Ouray and Redwash sites.

APPLICABLE REQUIREMENTS

Based on the information provided by Deseret Power Electric Cooperative in the Part 71 permit application of April 3, 2012, as amended on March 13 and 18, 2013, on January 27, 2014, and on April 3, 9, 10 and 15, 2014, and based on EPA regulatory analysis, EPA Region 8 has determined that the Bonanza plant is subject to the following applicable requirements, to be included in sections II and III of the Part 71 operating permit, for the reasons described below:

- **40 CFR Part 51, Appendix M, Methods 201 and 201A**: These Methods are applicable because the Federal PSD permit of February 2, 2001, requires Method 201 or 201A to be used for demonstrating compliance with the PM_{10} emission limit in the PSD permit (except if there is no reasonable way to eliminate liquid drops in the main boiler stack, in which case Method 5, 5A, 5B, 5D, 5E, 5G or 5H may be used). These Methods are referenced in section II.A.5.(a)(ii) of the draft Part 71 operating permit.

- **40 CFR 52.21, Prevention of Significant Deterioration:** Part 52.21 requirements to obtain a Federal PSD preconstruction permit apply to construction of new major stationary sources ("major" as defined in §52.21), as well as to major modifications of existing major stationary sources ("major modification" as defined in §52.21), in attainment areas where there is no applicable State implementation plan for PSD permitting. In issuing a PSD permit on February 4, 1981, for initial construction of Bonanza plant, a new major stationary source, EPA Region 8 determined that the plant is subject to Federal PSD permitting under §52.21. The Federal permit was updated and re-issued on February 2, 2001. Provisions from the 2001 Federal PSD permit that currently apply to the main boiler stack are listed in section of II.A.6 of the draft Part 71 operating permit, except for 40 CFR Part 60 provisions, which are incorporated into sections II.A.1 and II.A.2 of the draft permit.

  As discussed in Appendix A of this Statement of Basis, in comments on the August 2002 draft of the Part 71 permit, the National Park Service raised concerns regarding PSD applicability for a major modification that occurred as a result of a 2000 ruggedized rotor project at the facility. EPA has addressed that comment in Appendix A of this document. As explained in Appendix A, EPA proposes to undertake a separate and forthcoming PSD correction permitting action to address the PSD requirements that might have been triggered by the 2000 ruggedized rotor project. Thereafter, the revised PSD terms and conditions will be incorporated into this Part 71 permit, as required by condition III.D.1. of this proposed permit.

- **40 CFR Part 60, Subpart A: Standards of Performance for New Stationary Sources, General Provisions:** The requirements of Subpart A of Part 60 apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication of any standard in Part 60. The Bonanza plant was constructed after the date of publication of Subpart Da of Part 60 and is subject to Subpart Da (see below); therefore, the Bonanza plant is subject to requirements of Subpart A of Part 60. Those requirements are listed in section II.A.1 of the draft Part 71 operating permit.

- **<u>40 CFR Part 60, Subpart Da: Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978</u>:** The requirements of Subpart Da of Part 60 apply to electric utility steam generating units capable of combusting more than 73 megawatts (250 million Btu per hour) heat input of fossil fuel (either alone or in combination with any other fuel), and for which construction or modification is commenced after September 18, 1978. The Bonanza plant is a fossil-fuel-fired electric utility steam generating unit rated at approximately 500 megawatts output and with heat input capacity of 4,578 million Btu per hour. Construction commenced after September 18, 1978. Therefore, the Bonanza plant is subject to the requirements of Subpart Da of Part 60. Those requirements are listed in section II.A.2 of the draft Part 71 operating permit.

- **<u>40 CFR Part 60, Subpart Y: Standards of Performance for Coal Preparation Plants</u>:** The requirements of Subpart Y of Part 60 apply to coal preparation plants constructed or modified after October 24, 1974 and processing more than 200 tons per day of coal. "Coal preparation plant" is defined in Subpart Y as any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying. Affected facilities at coal preparation plants include the following: thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems (except for outdoor storage piles), and coal transfer and loading systems. The following facilities at the Bonanza plant are affected by Subpart Y: coal processing and conveying equipment (including breakers and crushers) and coal storage systems.

  In comments on the NSPS Subpart Y provisions in the August 2002 draft of the Part 71 permit, Deseret Power commented that any Subpart Y permit conditions should apply only to the coal crusher building. EPA has addressed that comment in Appendix A of this document. In accordance with the analysis provided in Appendix A, EPA has clarified draft permit condition II.B.2, to read as follows:

  <u>Requirements from 40 CFR Part 60, Subpart Y: Standards of Performance for Coal Preparation Plants</u>

  (a) The provisions of Subpart Y apply to coal preparation plants commencing construction or modification after October 24, 1974 and processing more than 200 tons per day of coal. "Coal preparation plant" is defined in Subpart Y as any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying. Affected facilities at coal preparation plants include the following equipment at the Bonanza plant: coal processing and conveying equipment (including breakers and crushers) and coal storage systems. "Coal storage system," as defined in Subpart Y, excludes open storage piles.

[40 CFR 60.250 & 60.251]

(b) The following provision of Subpart Y applies to the Bonanza plant: On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, the permittee shall not cause to be discharged into the atmosphere gases which exhibit 20 percent opacity or greater, from any coal processing and conveying equipment (including breakers and crushers) and coal storage systems. Opacity shall be determined by Method 9 and the procedures in 40 CFR 60.11.

[40 CFR 60.252(c) & 60.254(b)(2)]

(c) Method 9 observations shall be conducted no less frequently than monthly. Dates and locations where observations were conducted, as well as the opacities that were recorded, shall be identified in the semi-annual monitoring reports required by this permit.

[40 CFR 71.6(c)(1)]

- **<u>40 CFR Part 60, Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines</u>:** The requirements of Subpart IIII of Part 60 apply to owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines. This Subpart applies to the Emergency Diesel Generator at the Bonanza power plant, which was installed in 2013.

- **<u>40 CFR Part 60, Appendix A: Test Methods:</u>** All test methods in Appendix A of Part 60 that are necessary to demonstrate compliance with applicable requirements of Subpart Da of Part 60, Appendix F of Part 60, Part 75, Appendices A and B of Part 75, or the federal PSD permit issued on February 2, 2001, are applicable to the Bonanza plant. This includes Methods 1-7, 9 and 19. These Methods are referenced in several sections of the draft Part 71 operating permit and in several sections of Part 75 and Appendices A and B of Part 75.

- **<u>40 CFR Part 60, Appendix B: Performance Specifications:</u>** As required by Subparts A and Da and Appendix F of 40 CFR Part 60, and by Appendices A and B of Part 75, Performance Specifications 1, 2 and 3 for opacity, SO_2, NO_x and diluent (O_2 or CO_2) continuous monitors, respectively, are applicable to the monitoring systems at Bonanza plant.

- **<u>40 CFR Part 60, Appendix F: Quality Assurance Procedures (subtitled "Procedure 1: Quality Assurance Requirements for Gas Continuous Emission Monitoring Systems Used for Compliance Determination"):</u>** As stated in 40 CFR 60.13(a), for continuous monitoring systems required under applicable subparts of Part 60, the requirements of Appendix F apply, on and after December 4, 1987, where the continuous monitoring system is used to demonstrate compliance with emission limits in Part 60 on a continuous basis. Since the Bonanza plant is required, under Subpart Da of Part 60, to use gas continuous emission monitoring systems to demonstrate compliance with the SO_2 and NO_x emission limits of Subpart Da on a continuous basis, the SO_2 and NO_x continuous emission monitoring systems at the Bonanza plant are subject to requirements of Appendix F of Part 60.

- **<u>40 CFR Part 63, Subpart A: National Emission Standards for Hazardous Air Pollutants for Source Categories, General Provisions:</u>** The requirements of Subpart A of Part 63 apply to sources that are subject to the specific subparts of Part 63. For sources subject to Subparts ZZZZ and UUUUU of Part 63, the extent to which the General Provisions apply is laid out in Table 8 to Subpart ZZZZ and in Table 9 to Subpart UUUUU. These requirements are referenced in sections II.A.3 and II.A.4 of the draft Part 71 operating permit.

- **<u>40 CFR Part 63, Subpart ZZZZ: National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines:</u>** The requirements of Subpart ZZZZ of Part 63 apply to stationary reciprocating internal combustion engines (RICE) at a major or area source of HAP emissions. Applicability of specific requirements in Subpart ZZZZ is based on engine type (spark ignition (SI) versus compression ignition (CI)), type of use (emergency versus non-emergency), engine size (site brake HP rating), whether the engine is new or existing (based on date of engine startup), and whether the engine is at a major source or an area source of HAPs.

  Deseret Power is a major source of HAP emissions and has two engines that are subject to Subpart ZZZZ: the Emergency Diesel Generator and the Emergency Diesel Fire Pump. The Emergency Diesel Generator started up on January 8, 2013. The Emergency Diesel Fire Pump started up in the mid-1980s. As a new emergency-use stationary CI RICE with a site rating of more than 500 brake HP at a major HAP source, the Emergency Diesel Generator is subject only to an Initial Notification requirement. As an existing emergency-use stationary CI RICE with a site rating of less than 500 brake HP at a major HAP source, the Fire Pump is subject to certain maintenance practices found in section 1 of Table 2c of Subpart ZZZZ. These requirements are listed in section II.A.4 of the draft part 71 operating permit.

- **40 CFR Part 63, Subpart UUUUU: National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units:** The requirements of Subpart UUUUU of part 63 apply to coal-fired and oil-fired electric utility steam generating units (EGUs), defined in 40 CFR 63.10042 as fossil fuel fired units of more than 25 megawatts serving a generator that produces electricity for sale. Since Bonanza Unit 1 is rated at more than 25 MW and produces electricity for sale, the requirements of Subpart UUUUU apply to Unit 1. Those requirements are listed in section II.A.3 of the draft Part 71 operating permit.

- **40 CFR Part 64 (Compliance Assurance Monitoring):**

  As stated in §64.2, the requirements of Part 64 are applicable to each Pollutant Specific Emission Unit (PSEU) at a Part 71 major source that:

  (1) is subject to an emission limitation or standard for the applicable regulated pollutant, other than an emission limitation or standard exempted under §64.2(b)(1), and

  (2) uses a control device to achieve compliance with that limitation or standard, and

  (3) has potential pre-control emissions that exceed the major source threshold, for the pollutant to which the limitation or standard applies.

  Since the Bonanza plant is a Part 71 major source for particulate and for PM_{10}, and since:

  (1) the main boiler at Bonanza plant (Unit 1) is subject to emission limitations for particulate and PM_{10},

  (2) potential pre-control emissions of particulate matter and PM_{10} from the main boiler are above the major source threshold, and

  (3) a control device is used at the main boiler to achieve compliance with the particulate matter and PM_{10} limits,

  then Deseret Power must submit a Compliance Assurance Monitoring (CAM) plan under §64.4 for particulate matter and PM_{10} at the main boiler (Unit 1) at the Bonanza plant.

  Under §64.5(a), CAM plans for large PSEU's (those with post-control PTE greater than the major source threshold) must be submitted with the application for the initial Part 71 permit, if the application has not been submitted by April 20, 1998, or has been submitted but not determined complete by the permitting authority by that date. The main boiler at Bonanza plant is a large PSEU with regard to particulate matter, PM_{10}, NO_x and SO_2 emissions. The Part 71 application was not submitted until after April 20, 1998. It was submitted in March of 2000. Therefore, Deseret Power is subject to the requirement to submit a CAM plan for particulate matter and PM_{10} emissions. NO_x and SO_2 emissions are exempted from the requirement for a CAM plan, for the reasons explained below.

Under §64.2(b)(1), emission limitations or standards under Acid Rain Program are exempt from the requirements of Part 64. Also exempted are emission limitations or standards for which a Part 71 permit specifies a continuous compliance determination method. All SO_2 and NO_x emission limits for the Bonanza plant are exempted from the requirements of Part 64 because: (1) the draft Part 71 permit specifies a continuous compliance determination method for demonstrating compliance with those limits, and (2) the Acid Rain Program contains emission limitations for SO_2 and NO_x at the Bonanza plant.

On February 26, 2014, EPA wrote to Deseret Power (via email from Mike Owens to Eric Olsen) to request that a CAM plan be submitted within 30 days, if at all possible. EPA asked to be notified if Deseret needs more time. Deseret Power submitted the requested CAM plan on April 3, 2014. EPA has used that CAM plan as a basis for the proposed CAM requirements which appear in proposed permit condition II.A.6.(a)(viii).

- **40 CFR Part 72 (Acid Rain Program – Permits regulation):** As provided for in 40 CFR §72.6(a), the main boiler at Bonanza plant is an affected unit, and the plant is an affected source, under the Acid Rain Program, and therefore is subject to the requirements of 40 CFR parts 72 through 78. As provided for in §72.9(a)(1), the owners and operators of the Bonanza plant are subject to the standard permit requirements in §72.9. Those requirements appear in section II.A.7 of the draft Part 71 operating permit.

- **40 CFR Part 73 (Acid Rain Program – Sulfur dioxide allowance system):** As provided for in §73.2(a), the requirements of Part 73 apply to the Bonanza plant because, under §72.6, it is an affected source, and the Bonanza plant's main boiler is an affected unit. Requirements of Part 73 appear in sections II.A.7.(b), (c), (f) and (h) of the draft Part 71 operating permit.

- **40 CFR Part 75 (Acid rain program – Continuous emission monitoring):** As provided for in §75.2, the requirements of part 75 apply to the Bonanza plant's main boiler because, under §72.6, it is an affected unit, and is subject to Acid Rain emission limitations or reduction requirements for SO_2 or NO_x. The requirement to comply with part 75 appears in section II.A.7.(b) of the draft Part 71 operating permit.

- **<u>40 CFR Part 75, Appendix A: Specifications and Test Procedures</u>:** The requirements of Appendix A of Part 75 apply to the Bonanza plant because Part 75 requires all CEMS that are subject to Part 75 to comply with Appendices A and B of Part 75. The requirement to comply with Part 75 appears in section II.A.7.(b) of the draft Part 71 operating permit.

- **<u>40 CFR Part 75, Appendix B: Quality Assurance and Quality Control Procedures</u>:** The requirements of Appendix B of Part 75 apply to the Bonanza plant because Part 75 requires all CEMS that are subject to Part 75 to comply with Appendices A and B of Part 75. The requirement to comply with Part 75 appears in section II.A.7.(b) of the draft Part 71 operating permit.

- **<u>40 CFR Part 75, Appendix F: Conversion Procedures</u>:** The requirements of Appendix F of Part 75 apply to the Bonanza plant because Appendix F applies to any monitoring system required under Part 75. The requirement for Bonanza's monitoring system to comply with Part 75 appears in section II.A.7.(b) of the draft Part 71 operating permit.

- **<u>40 CFR Part 75, Appendix G: Determination of CO_2 Emissions</u>:** Appendix G is an optional procedure, for sources with Part 75 monitoring systems, for estimating mass emissions of CO_2 as the sum of CO_2 emissions from combustion and, if applicable, CO_2 emissions from sorbent used in a wet flue gas desulfurization system. The option for utilizing Appendix G is available for the Bonanza plant because the plant has a Part 75 monitoring system and uses sorbent in a wet flue gas desulfurization control system.

- **<u>40 CFR Part 76 (Acid Rain Program – Acid rain nitrogen oxides emission reduction program):</u>** As provided for in §76.1(a), the requirements of Part 76 apply to the Bonanza plant's main boiler because it is a coal-fired utility unit that is subject to an Acid Rain emissions limitation or reduction requirement for SO_2 under Phase I or Phase II pursuant to sections 404, 405, or 409 of the Clean Air Act. The requirement to comply with Part 76 appears in section II.A.7.(d) of the draft part 71 operating permit.

- **<u>40 CFR Part 77 (Acid Rain Program – excess emissions):</u>** As provided for in §77.1(a), the requirements of Part 77 apply to the owners and operators and, to the extent applicable, the designated representative of the Bonanza plant because, under §72.6, the plant is an affected source and the main boiler is an affected unit under the Acid Rain Program. The requirement to comply with Part 77 appears in section II.A.7.(e) of the draft Part 71 operating permit.

- **<u>40 CFR Part 78 (Acid Rain Program – appeal procedures):</u>** As provided for in §78.1(a)(1), the provisions of Part 78 are applicable to the Bonanza plant because those provisions govern appeals of any final decision of the EPA Administrator under 40 CFR Parts 72 through 77, *provided* that matters listed in §78.3(d), and preliminary, procedural or intermediate decisions, such as draft Acid Rain permits, may not be appealed. Part 78 is referenced in section II.A.7.(g)(vii) of the draft Part 71 operating permit.

- **40 CFR Part 82, Subpart F (Stratospheric Ozone and Climate Protection, Recycling and Emissions Reduction):** The requirements of Subpart F of part 82 apply to any air conditioning "appliances" at the Bonanza plant as defined in §82.152. The Part 71 permit application for the Bonanza plant (at page H-9) identifies Subpart F of Part 82 as being applicable to the Bonanza plant. The applicable requirements are included in section III.G. of the draft Part 71 operating permit.

- **40 CFR Part 82, Subpart H (Stratospheric Ozone and Climate Protection, Halon Emissions Reduction):** The requirements of Subpart H of Part 82 are applicable to any fire extinguishers containing Halon 1211, 1301 or 2402. A letter from the permittee to EPA Region 8 on May 30, 2002, stated that there are fire extinguishers at the Bonanza plant containing about 4,000 pounds of Halon 1301, therefore Subpart H of Part 82 is applicable to the Bonanza plant. An amendment to the updated Part 71 permit application for the Bonanza plant, submitted to EPA on March 18, 2013, confirmed that Subpart H is applicable. The applicable requirements are included in section III.G of the draft Part 71 operating permit.

REQUIREMENTS THAT ARE NOT APPLICABLE

The following analysis of non-applicability is based on EPA regulations. This analysis is limited to those sections of the CFR for which EPA believes an explanation for non-applicability is warranted. This analysis does not constitute a permit shield. See section III.E of the draft Part 71 operating permit for language about a permit shield.

- **40 CFR Part 60 (Standards of Performance for New Stationary Sources):**

  Subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971): The requirements of this subpart are not applicable to the Bonanza plant because, as stated in §60.40(e), any facility covered under Subpart Da of Part 60 is not covered by Subpart D. The Bonanza plant is covered under Subpart Da.

  Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units): The requirements of this subpart are not applicable to the Bonanza plant because, as stated in §60.40b(e), steam generating units meeting the applicability requirements under Subpart Da of Part 60 are not subject to Subpart Db. The Bonanza plant meets the applicability requirements of Subpart Da.

  Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units): The requirements of this subpart are not applicable to the Bonanza plant because, as stated in §60.40c(a), Subpart Dc applies only to steam generating units with maximum design heat input capacity of 29 megawatts (100 MMBtu/hr) or less. The Bonanza plant capacity is greater than 29 megawatts.

Subpart K (Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978): As stated in §60.110(c), Subpart K is applicable to petroleum liquid storage vessels for which: (1) construction or modification commenced between March 8, 1974 and May 19, 1978, and have capacity greater than 40,000 gallons, or (2) construction or modification commenced between June 11, 1973 and May 19, 1978, and have capacity greater than 65,000 gallons. As stated in §60.111(b), the term "petroleum liquids" excludes #2-D and #4-D diesel fuel oil and excludes #2 through #6 grade fuel oil. The two 288,000-gallon diesel fuel oil storage tanks at the Bonanza plant were constructed after May 19, 1978 and do not store "petroleum liquids" as defined in Subpart K. The 10,000-gallon gasoline and 20,000-gallon diesel storage tanks at the Bonanza plant were also constructed after May 19, 1978, and are smaller than 40,000 gallons, and diesel is excluded from applicability. Therefore, the requirements of Subpart K are not applicable to the Bonanza plant.

Subpart Ka (Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to June 23, 1984): As stated in §60.110a(a), Subpart Ka is applicable to petroleum liquid storage vessels for which construction is commenced after May 18, 1978, and have capacity greater than 40,000 gallons. As stated in §60.111a(b), "petroleum liquids" excludes #2-D and #4-D diesel fuel oil and excludes #2 through #6 grade fuel oil. The two 288,000-gallon diesel fuel oil storage tanks at the Bonanza plant do not store "petroleum liquids" as defined in Subpart Ka. The 10,000-gallon gasoline and 20,000-gallon diesel storage tanks at the Bonanza plant are smaller than 40,000 gallons, and diesel is excluded from applicability. Therefore, the requirements of Subpart Ka are not applicable to the Bonanza plant.

Subpart Kb (Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After July 23, 1984): As stated in §60.110b(a), Subpart Kb is applicable to storage vessels greater or equal to 40 cubic meters capacity (equivalent to 10,567 gallons) that are used to store volatile organic liquids and for which construction, reconstruction or modification commenced after July 23, 1984. The two 288,000-gallon diesel fuel oil storage tanks at the Bonanza plant were constructed prior to July 23, 1984, as were the 10,000-gallon gasoline and 20,000-gallon diesel storage tanks at the Bonanza plant. Therefore, the requirements of Subpart Kb are not applicable to the Bonanza plant.

Subpart GG (Standards of Performance for Stationary Gas Turbines): The requirements of Subpart GG are not applicable to the Bonanza plant because there are no stationary gas turbines at the plant.

- **40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants):** Part 61 is not applicable to the Bonanza plant because the plant is not within any of the industrial categories covered by Part 61, and/or because the Bonanza plant does not have any types of processes or process units covered by Part 61.

- **40 CFR Part 68 (Chemical Accident Prevention Program):**

  As stated in §68.10(a), the requirements of Part 68 are applicable to owners and operators of stationary sources that have more than a threshold quantity of a Part 68 listed substance in a process, as determined under §68.115. According to an addendum to the original Part 71 permit application for the Bonanza plant, submitted to EPA via e-mail on February 26, 2002, the Bonanza plant has no Part 68 listed substances in any processes that are above the threshold quantities in Part 68. Therefore, the requirements of Part 68 are not applicable to the Bonanza plant.

  Under § 68.10(a), the Bonanza plant would become subject to the requirement to develop and submit an RMP:

  (a) three years after the date on which a regulated substance is first listed under 40 CFR 68.130, or

  (b) the date on which a regulated substance under Part 68 is first present above a threshold quantity in a process.

- **40 CFR Part 75, Appendix D (Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units):** The requirements of Appendix D of Part 75 are applicable to emitting units under the Acid Rain Program that are gas-fired or oil-fired and have chosen Appendix D as an option for calculating and reporting SO_2 emissions. The requirements of Appendix D are not applicable to the Bonanza plant because the plant has no gas-fired or oil-fired emitting units that are subject to Acid Rain Program.

- **40 CFR Part 75, Appendix E (Optional NO_x Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units):** The requirements of Appendix E of Part 75 are applicable to emitting units under Acid Rain Program that are gas-fired or oil-fired peaking units ("peaking unit" as defined in 40 CFR Part 72). The requirements of Appendix E are not applicable to the Bonanza plant because the plant has no gas-fired or oil-fired emitting units that are subject to Acid Rain Program, nor any peaking units.

- **<u>40 CFR Part 82 (Protection of Stratospheric Ozone), Subparts A, B, C, D, E and G</u>:** Subpart A of Part 82 pertains to Production and Consumption Controls for producers and importers of ozone-depleting substances. Subpart B of Part 82 pertains to Servicing of Motor Vehicle Air Conditioners. Subpart C of Part 82 pertains to a Ban on Nonessential Products containing ozone-depleting substances. Subpart D of Part 82 pertains to Federal Procurement of ozone-depleting substances. Subpart E of Part 82 pertains to Labeling of Products Using Ozone-Depleting Substances. Subpart G of Part 82 pertains to Significant New Alternatives Policy Program regarding ozone-depleting substances. None of these subparts of Part 82 contain any requirements applicable to stationary sources, and therefore do not contain any requirements applicable to the Bonanza plant.

- **<u>40 CFR Part 98 (Mandatory Greenhouse Gas Reporting Rule)</u>:** This rule requires sources above certain emission thresholds to calculate, monitor and report greenhouse gas emissions. According to the definition of "applicable requirement" in 40 CFR 71.2, neither Part 98, nor CAA section 307(d)(1)(V), the CAA authority under which Part 98 was promulgated, are listed as applicable requirements for the purpose of Title V permitting. Although Part 98 is not an applicable requirement under 40 CFR Part 71 and is not included in the draft Part 71 operating permit, the permittee is not relieved from the requirement to comply with the rule separately from compliance with the Part 71 operating permit. It is the responsibility of each source to determine applicability to Part 98 and to comply if necessary.

<u>COMPLIANCE SCHEDULE</u>

40 CFR § 71.6(c)(3) requires Part 71 operating permits to include a schedule of compliance consistent with §71.5(c)(8). Specific provisions of §71.5(c)(8) are listed in section III.D of the draft Part 71 operating permit. Section III.D.1. includes a proposed requirement for Deseret Power to submit to EPA a request for an administrative amendment to revise the Part 71 permit, to include the terms and conditions of a PSD permit correction, within 60 days after EPA issues a final and effective Federal PSD permit correction for this facility.

<u>OTHER CLEAN AIR ACT REGULATORY PROGRAMS</u>

EPA has developed a national regulatory program for preconstruction review of major sources in nonattainment areas and of minor sources in both attainment and nonattainment areas in Indian country. (See Tribal NSR Rule, 76 FR 38746 (July 1, 2011).) This program established, where appropriate, control requirements for sources that would be incorporated into part 71 permits.

To establish additional applicable, federally-enforceable emission limits, EPA Regional Offices will, as necessary and appropriate, promulgate Federal Implementation Plans (FIPs) that will establish Federal requirements for sources in specific areas. EPA will establish priorities for its direct Federal implementation activities by addressing as its highest priority the most serious threats to public health and the environment in Indian country that are not otherwise being adequately addressed.

Further, EPA encourages and will work closely with all tribes wishing to develop Tribal Implementation Plans (TIPs) for approval under the Tribal Authority Rule. EPA intends that its federal regulations created through a FIP will apply only in those situations in which a tribe does not have an approved TIP. The Ute Tribe does not have an EPA-approved Tribal Implementation Plan.

GENERAL EPA AUTHORITY TO ISSUE PART 71 PERMITS

Title V of the Clean Air Act requires that EPA promulgate, administer, and enforce a Federal operating permits program when a state does not submit an approvable program within the time frame set by title V or does not adequately administer and enforce its EPA-approved program. On July 1, 1996 (61 FR 34202), EPA adopted regulations codified at 40 CFR Part 71, setting forth the procedures and terms under which the Agency would administer a Federal operating permits program. These regulations were updated on February 19, 1999 (64 FR 8247) to incorporate EPA's approach for issuing Federal operating permits to stationary sources in Indian country.

As described in 40 CFR 71.4(a), EPA will implement a Part 71 program in areas where a state, local, or tribal agency has not developed an approved part 70 program. Unlike states, Indian tribes are not required to develop operating permits programs, though EPA encourages tribes to do so. See, e.g., Indian Tribes: Air Quality Planning and Management (63 FR 7253, February 12, 1998) (also known as the “Tribal Authority Rule”). Therefore, within Indian country, EPA will administer and enforce a Part 71 Federal operating permits program for stationary sources until a tribe receives approval to administer its own operating permits program. The Ute Tribe has not received such approval.

USE OF ALL CREDIBLE EVIDENCE

Determinations of deviations, continuous or intermittent compliance status, or violations of the permit are not limited to the testing or monitoring methods required by the underlying regulations or this permit; other credible evidence (including any evidence admissible under the Federal Rules of Evidence) must be considered by the source and EPA in such determinations.

PUBLIC PARTICIPATION AND PUBLIC HEARING

1. Public Notice.

As described in 40 CFR 71.11(a)(5), all Part 71 draft operating permits shall be publicly noticed and made available for public comment. Details on the public notice of permit actions and public comment period is described in 40 CFR 71.11(d).

There will be a 45 day public comment period for actions pertaining to this draft permit, to begin on May 1, 2014. Public notice has been given for this draft permit by mailing a copy of the notice to the permit applicant, the affected state and Tribal air pollution control agencies, city and county executives, and to the federal land managers for the area where the source is located. A copy of the notice has also been provided to all persons who have submitted a written request to be included on the mailing list. If you would like to be added to our mailing list to be informed of future actions on these or other Clean Air Act permits issued by EPA, please send your name and address to the address listed below:

Michael Owens, Part 71 Permit Contact
U.S. Environmental Protection Agency, Region 8
1595 Wynkoop Street (8P-AR)
Denver, Colorado 80202-1129
owens.mike@epa.gov

Public notice has been published in the Ute Bulletin on April 25, 2014, in the Salt Lake Tribune on April 27, 2014, and in the Uintah Basin Standard and Vernal Express on April 29, 2014, giving opportunity for public comment on the draft permit.

2. Opportunity for Comment

Members of the public may review a copy of the draft permit prepared by EPA, the application, this statement of basis for the draft permit, and all supporting materials for the draft permit. Copies of these documents are available at:

Uintah County Clerk's Office
147 East Main Street, Suite 2300
Vernal, Utah 84078
Phone 435-781-5361

Ute Indian Tribe
Energy & Minerals Dept.
988 South 7500 East
Fort Duchesne, Utah 84026
Phone 435-725-4900

US EPA Region 8
Air Program Office
1595 Wynkoop Street (8P-AR)
Denver, Colorado 80202-1129
Phone 303-312-6440

All documents at the US EPA Region 8 office are available for review on Monday through Friday, from 8:00 a.m. to 4:00 p.m. (excluding federal holidays). Electronic copies of the draft permit, statement of basis and permitting record may also be viewed at: http://www2.epa.gov/region8/air-permit-public-comment-opportunities.

Any interested person may submit written comments on the draft Part 71 operating permit during the public comment period to the Part 71 Permit Contact at the address listed in section 1 above, or by email using instructions on the EPA Region 8 website address listed above. All comments received on or before the end of the 45-day public comment period shall be considered by EPA in arriving at a final decision on the permit. EPA will keep a record of the commenters and of the issues raised during the public participation process.

Anyone, including the applicant, who believes any condition of the draft permit is inappropriate must raise all reasonable ascertainable issues and submit all arguments supporting their position by the close of the public comment period. Any supporting materials submitted must be included in full and may not be incorporated by reference, unless the material has been already submitted as part of the administrative record in the same proceeding or consists of state or federal statutes and regulations, EPA documents of general applicability, or other generally available reference material.

The final permit is a public record that can be obtained upon request. A statement of reasons for changes made to the draft permit and responses to comments received will be sent to all persons who commented on the draft permit.

3. Public Hearing

EPA has scheduled a public hearing on this permit action, to be held on June 3, 2014, from 1:00 p.m. to 4:00 p.m., and from 6:00 p.m. to 8:00 p.m., at the Ute Tribal Auditorium, located at 6964 East 1000 South (2 miles South of Bottle Hollow), Fort Duchesne, Utah 84026. EPA will provide public notice of the public hearing. At the hearing, any person may submit oral or written statements and data concerning the draft permit. All comments received at the public hearing shall be considered by EPA in arriving at a final decision on the permit.

4. Appeal of Permits

Any request for review of the final Part 71 permit issued in this action will be conducted in accordance with 40 CFR § 71.11(l). Within 30 days after the issuance of a final permit decision, any person who filed comments on the draft permit or participated in the public hearing may petition the Environmental Appeals Board to review any condition of the permit decision. Any person who failed to file comments or participate in the public hearing may petition for administrative review only if the changes from the draft to the final permit decision or other new grounds were not reasonably foreseeable during the public comment period. The 30 day period to appeal a permit begins with EPA's service of the notice of the final permit decision.

The petition to appeal a permit must include a statement of the reasons supporting the review, a demonstration that any issues were raised during the public comment period, or a demonstration that it was impracticable to raise the objections within the public comment period or that the grounds for such objections arose after such period. When appropriate, the petition may include a showing that the condition in question is based on a finding of fact or conclusion of law which is clearly erroneous; or, an exercise of discretion, or an important policy consideration which the Environmental Appeals Board should review.

5. Petition to Reopen a Permit for Cause

Any interested person may petition EPA to reopen a permit for cause, and EPA may commence a permit reopening on its own initiative. EPA will only revise, revoke and reissue, or terminate a permit for the reasons specified in 40 CFR §71.7(f) or §71.6(a)(6)(i). All requests must be in writing and must contain facts or reasons supporting the request. If EPA decides the request is not justified, it will send the requester a brief written response giving a reason for the decision. Denial of these requests is not subject to public notice, comment, or hearings. Denials can be informally appealed to the Environmental Appeals Board by a letter briefly setting forth the relevant facts.

6. Notice to Affected States/Tribes

As described in 40 CFR § 71.11(d)(3)(i), public notice shall be given by mailing a copy of the notice to the air pollution control agencies of affected states, tribal and local air pollution control agencies which have jurisdiction over the area in which the source is located, the chief executives of the city and county where the source is located, any comprehensive regional land use planning agency and any state or Federal Land Manager whose lands may be affected by emissions from the source. The following entities have been notified:

Ute Indian Tribe, Environmental Programs Office
Town of Vernal, Mayor
Uintah County, County Clerk
State of Colorado, Department of Public Health & Environment
State of Utah, Department of Environmental Quality
National Park Service, Air Program, Denver, Colorado
U.S. Department of Agriculture, Forest Service, Rocky Mountain Region

Statement of Basis – Appendix A

Consideration of Comments Received on the 2002 Draft Title V Permit

Introduction

As summarized in Section 4 of the Statement of Basis, the Title V and Prevention of Significant Deterioration (PSD) permitting for Deseret Bonanza facility spans more than 30 years and involves a variety of permitting actions taken by both EPA and the State of Utah. In recognition of the unique permitting posture for this facility and the current draft Title V Permit, EPA is providing this Appendix to the Statement of Basis to address several considerations that have arisen since we first provided an opportunity for public comment on the draft Title V Permit in 2002. Today's draft permit is different from the draft permit previously noticed in 2002, and a new public comment opportunity is now being offered. Thus, EPA is not under an obligation to respond to the previously received adverse comments on the 2001 version of the permit. However, to assist with understanding of the basis for the current draft Title V Permit, EPA evaluated the adverse comments from Deseret and the National Park Service (NPS) received during that public comment period, particularly in light of the current proposed draft permit terms and conditions, and is providing some responses to the extent they are relevant to the current proposal.

I. Deseret Comments on 2002 Draft Title V Permit Regarding Applicability of 40 CFR Part 60, Subpart Y

Deseret Power submitted comments on the 2002 draft Title V Permit regarding the applicability of the NSPS Subpart Y provisions to the Bonanza facility. The requirements of Subpart Y of Part 60 apply to coal preparation plants constructed or modified after October 24, 1974 and processing more than 200 tons per day of coal. "Coal preparation plant" is defined in Subpart Y as any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying. Affected facilities at coal preparation plants include the following: thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems (except for outdoor storage piles), and coal transfer and loading systems.

In its comments on the NSPS Subpart Y provisions in the August 2002 draft of the Part 71 permit, which were submitted to EPA on September 16, 2002, Deseret Power commented that any Subpart Y permit conditions should apply only to the coal crusher building. Deseret stated that the EPA comments and the permit language allude to the fact that during the operation of the crusher, the coal handling equipment is treated as part of the Subpart Y system and when the crusher is not running, the coal handling equipment is part of the Subpart Da facility. Deseret stated that the coal unloading, storage and conveying systems at the plant are part of the Subpart Da facility and not part of the Subpart Y facility. The above mentioned systems run independently of the crusher and are an integral part of the entire generating system, not the crusher. Also, Deseret noted that 40 CFR 60.251(i) refers to equipment used to transfer or load coal for shipment, but no coal is shipped from the plant.

As part of this permitting action, EPA examined Deseret's 2002 comment and disagrees with Deseret's comment that when the crusher is not running, the coal unloading, storage and conveying systems at the plant are part of the Subpart Da facility instead of the Subpart Y facility. There is nothing in Subparts Y or Da that says applicability of Subpart Da to a facility affects applicability of Subpart Y to the same facility. Also, there is nothing in Subpart Y that says the ability of some portion of the coal handling system to run independently of the crusher means that any portion of the system is not part of the Subpart Y affected facility. 40 CFR 60.250(a) simply says the Subpart Y affected facility includes coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems.

EPA has, however, re-examined the Subpart Y provisions in the 2002 draft permit and finds that the draft permit was inaccurate in saying the opacity limit in Subpart Y only applies when the facility is preparing coal as defined in §60.251(a), i.e., only during breaking, crushing or screening of the coal. (EPA notes that the definition in §60.251(a) also includes wet or dry cleaning and thermal drying, but these processes are not conducted at the Bonanza plant.) §60.252(c), which specifies the 20% opacity limit, says the limit applies to any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal. There is no statement that the limit only applies during breaking, crushing or screening.

With regard to Deseret's comment about §60.251(i), EPA acknowledges that the definition of "transfer and loading system" does not apply to the Bonanza plant, since no coal is shipped from the plant. Therefore, EPA proposes that "transfer and loading system" should not be part of the Subpart Y language in the Part 71 permit and has proposed terms in the draft Title V Permit to clarify the Subpart Y requirements for the Bonanza facility. Those clarified terms may be found in the Applicable Requirements section of this Statement of Basis.

II. NPS Comments on 2002 Draft Title V Permit Regarding Applicability of PSD

The NPS comments on the 2002 draft Title V Permit asserted, in regard to a ruggedized rotor project that Deseret Power constructed in 2000, that “there is reason to believe actual emissions may have increased by ‘significant’ amounts and that PSD may have been triggered,” if past actual emissions are compared to the allowable emission limits in the draft Title V permit. Also, the NPS stated that the Title V permit “should not be issued that essentially incorporates what may be a defective permit.” Since PSD permit terms and conditions must be included in the title V permit, consistent with the definition of “applicable requirements” in the title V regulations, the NPS comment suggests the possibility that EPA may have initially drafted a title V permit term which incorporates an applicable PSD permit requirement that contravenes the PSD regulations due to an error in a previous PSD non-applicability decision.

PSD non-applicability is evaluated under the minor NSR program. Emission limits originating in a previously-issued PSD permit cannot be revised in a Title V permit without first (or simultaneously) revising the PSD permit under the applicable PSD regulations. *See* Letter from J. Seitz, EPA, to R. Hodanbosi and C. Lagges, STAPPA/ALAPCO (May 20, 1999), Enc. A at 4; Nucor Steel, at pp. 15-16. The applicable federal PSD regulations, 40 CFR 52.21, do not include provisions for amending or revising permits. However, the EPA has issued guidance over the years with respect to revising federal PSD permits, including guidance specifically directed at revising BACT limits. See the November 19, 1987, Memorandum titled "Request for Determination on Best Available Control Technology (BACT) Issues - Ogden Martin Tulsa Municipal Waste Incineration Facility." Given the comment, the availability of information on actual emissions before and after the project, and the unusual circumstances leading to the issuance of the PSD permit, EPA made a decision to further investigate the issue prior to responding to the comment. To evaluate this issue, EPA requested and considered information from Deseret; and also independently gathered and analyzed additional information.

While EPA is sensitive to the fact that under the rules applicability of the major NSR program must be determined in advance of construction, under section 504 of the Clean Air Act, the final Title V permit issued by EPA for this facility must contain terms and conditions necessary to assure compliance with the applicable requirements of the Act, including PSD requirements. In carrying out our Title V permitting obligations, EPA has preliminarily determined that the PSD permit EPA issued in 2001 omitted certain PSD permitting requirements and that EPA failed to analyze and apply the PSD regulations correctly when issuing that permit. Among the requirements omitted was a Best Available Control Technology (BACT) analysis for NO_x. To correct our permitting error, we intend to propose – in a separate permitting action in the near future – a PSD correction permit for this facility. The proposed Title V permit that is part of today's action includes permit terms for updating the Title V permit with the requirements corresponding to the corrected PSD permit conditions, at proposed condition III.D.1. We include an analysis below of the basis for our preliminary PSD applicability determination and to support the proposed terms and conditions in the draft Title V permit requiring Deseret to request for an administrative permit amendment to revise the Part 71 permit to incorporate the terms of the final and effective Federal PSD permit correction for this facility. *See* Draft Permit, Section III.D. "Compliance Schedule and

Progress [40 CFR 71.6(c)(3) and (4); 71.5(c)(8)(iii)]."

Applicable PSD Requirements

Title V permits are required to assure compliance with all applicable requirements. Under 40 C.F.R. § 71.1(b), "[a]ll sources subject to operating permit requirements shall have a permit to operate that assures compliance by the source with all applicable requirements." "Applicable requirements" are defined in 40 C.F.R. § 71.2 to include "(1) [a]ny standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA through rulemaking under title I of the [Clean Air] Act that implements the relevant requirements of the Act, including any revisions to that plan promulgated in [40 C.F.R.] part 52 of this chapter." Under the Act, each state is required to have an implementation plan that includes, among other things, "a program to provide for … regulation of the modification and construction of any stationary source within the areas covered by the plan as necessary to assure that the national ambient air quality standards are achieved, including a permit program as required in parts C and D of this subchapter."[1] Parts C and D of the Title I of the Clean Air establish a preconstruction permitting program for major sources of air pollutants that is known collectively as New Source Review, and includes pollutant-specific requirements under the Prevention of Significant Deterioration and nonattainment New Source Review programs.[2] Thus, applicable requirements for new and modified major stationary sources[3] include the requirement to obtain a preconstruction permit that

[1] CAA § 110(a)(2)(C); 42 U.S.C. § 7410(a)(2)(C).
[2] CAA §§ 165 and 173; 42 U.S.C. §§ 7475, 7503.
[3] "Major stationary source" is defined, inter alia, as a fossil fuel-fired steam electric plant of more than 250

complies with applicable new source review and PSD requirements.[4] Applicable requirements also include the terms and conditions of such permits. 40 C.F.R. 71.2 (paragraph (2) of the definition of "applicable requirement").

At issue here is the PSD program contained in Part C of the CAA. The PSD program applies to areas of the country, such as Uintah and Ouray Indian Reservation, that are designated as attainment or unclassifiable for the National Ambient Air Quality Standards (NAAQS).[5] In such areas, a major stationary source may not begin construction or undertake certain modifications without first obtaining a PSD permit.[6]

In broad overview, the PSD program includes two central requirements that must be satisfied before the permitting authority may issue a permit. The program: (1) limits the impact of new or modified major stationary sources on ambient air quality; and (2) requires the application of state-of-the-art pollution control technology, known as Best Available Control Technology (BACT), for each pollutant subject to regulation under the Act.[7] The CAA further defines BACT as

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

CAA § 169(3).

British thermal units (Btu) per hour heat input with the potential to emit 100 tons per year or more of certain criteria pollutants, such as nitrogen oxide (NO[x]), sulfur dioxide (SO[2], or particulate matter PM). 40 C.F.R. § 52.21(b)(1).

[4] 40 C.F.R. § 71.2.

[5] CAA §§ 160-169, 42 U.S.C. §§ 7470-7479.

[6] CAA § 165(a)(1), 42 U.S.C. § 7475(a)(1).

[7] CAA §§ 165(a)(3) & (4), 42 U.S.C. §§ 7475(a)(3) and (4).

The EPA has two largely identical sets of regulations implementing the PSD program: one set, found at 40 C.F.R. § 51.166, contains the requirements that state PSD programs must meet to be approved as part of a Tribal or State Implementation Plan; the other set of regulations, found at 40 C.F.R. § 52.21, contains the EPA's federal PSD program. As EPA administers the PSD program for sources located on the Uintah and Ouray Indian Reservation,[8] the applicable requirements of the Act for new major sources or major modifications include the requirement to comply with PSD requirements, 40 C.F.R. § 52.21.[9]

The Deseret Bonanza plant is a fossil fuel-fired steam electric generating plant of more than 250 million British Thermal units per hour (MMBtu/hr) heat input capacity, with the potential to emit 100 tons per year or more of any pollutant subject to regulation under the Act, and therefore it is a major stationary source under the PSD regulations.[10] The PSD rules at 40 C.F.R. § 52.21(j)(3) require that a major modification to a major stationary source apply BACT for each regulated New Source Review (NSR) pollutant for which it would result in a significant net emissions increase at the source. "Major modification" is defined at 40 C.F.R. § 52.21(b)(2). The rules also allow certain emissions to be excluded from determining whether a modification will result in a significant net emissions increase. Relevant to this permitting action, the definition of "Representative actual annual emissions" at 40 C.F.R. § 52.21(b)(33) that was in effect at the time EPA issued the PSD permit in 2001 says that the projection of future actual emissions shall:

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[8] 40 C.F.R. § 52.2346.
[9] See, e.g., 40 C.F.R § 71.2.
[10] 40 CFR § 52.21(b)(1)(i)(a).

> Exclude, in calculating any increase in emissions that results from the particular physical change or change in the method of operation at an electric utility steam generating unit, that portion of the unit's emissions following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole.

Thus, in assessing whether modification of an existing unit will result in an increase in actual emissions, EPA has explained that the PSD regulations provide that "when a projected increase in equipment utilization is in response to a factor such as growth in the market demand," the owner or operator "may subtract the emission increases from unit's projected actual emissions"[11] if two requirements are met. The exclusion should apply only when "[t]he unit could have achieved the necessary level of utilization during the consecutive 24-month period you selected to establish the baseline actual emissions" and "the increase is not related to the physical or operational change(s) made to the unit."[12] In other words, EPA explained that where an increase in emissions "could not have occurred during the representative baseline period but for the physical or operational change, that change will be deemed to have resulted in the increase."[13] Finally, "[a]lthough a source may vary its hours of operation or production as part of its everyday operations, an increase in emissions attributable to an increase in hours of operation or production rate which is the result of a construction-related activity is not excluded from [PSD] review (see WEPCO, 893 F.2d at 916 n.11; Puerto Rican Cement,

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[11] 67 Fed.Reg. 80,186, 80203 (Dec. 31, 2012).
[12] Id.
[13] 57 Fed.Reg. 32,314, 32,327 (July 21, 1992).

889 F.2d at 298)."[14]

Adverse Comments on the 2002 Draft Title V Permit Regarding PSD Applicability

During the public comment period for the initial draft Title V permit in 2002, the NPS commented that a ruggedized rotor installation that Deseret constructed in 2000 may have increased actual emissions by "significant" amounts as defined in the regulations, thereby triggering the PSD major source modification permitting requirements in 40 C.F.R. § 52.21, explaining that:

> We are especially interested in how the State made the determination in 1998 that the "ruggedized rotor" project was only a synthetic minor modification and did not trigger PSD review. The 1998 Approval Order and supporting documentation state that boiler heat input was increased from 4381 MMBtu/hr to 4578 MMBtu/hr, and that approximately 20 MW from the upgrade will result from an increase in steam flow produced by the boiler. To date, the boiler has not been operated at its peak potential due to limitations of steam flow at the existing Turbine Generator. The Project will allow the Turbine Generator to accept all of the steam flow the Boiler is capable of producing. While the Ruggedized Rotor by itself will not result in any change to Bonanza 1's emissions, the increased capacity of the Turbine Generator to handle the Boiler's peak capacity will increase the Bonanza plant's overall potential to emit (PTE).
>
> To our knowledge, we were never advised of, nor involved in, that action. We do not understand how this boiler could be up-rated from 440 MW to 500 MW without an increase in actual emissions, unless Deseret acted to offset the increase in actual emissions by some physical change or change in its method of operation. We are concerned that the reductions in allowable lb/mmbtu emission rates mentioned in the "Permitting History" do not reflect a reduction in actual emissions and what we are seeing are merely "paper" reductions.
>
> We believe that these concerns are justified if one looks at past actual emissions at this plant compared to emission limits contained in the March 16, 1998 "Approval Order for Modification of Bonanza One Power Plant Emission Limits." For example, EPA's emissions data for 2000 (prior to

[14] Id. at 32,328 (emphasis added).

> installation of the “ruggedized rotor”) show that SO_2 emissions were 1,038 tons, while NO_x emissions were 5,692 tons. Because the 1998 Approval Order and the draft Title V permit allow SO_2 emissions of 1,968 tons and NO_x emissions of 10,030 tons, there is reason to believe actual emissions may have increased by “significant” amounts and that PSD may have been triggered. We believe that a Title V permit should not be issued that essentially incorporates what may be a defective permit.

Discussion of the 2001 Federal PSD Permit

The Permitting History in section IV of this Statement of Basis provides a general overview of the various permitting actions for the Bonanza plant. With regard to the PSD applicability issues raised by the 2002 NPS comment, the 2001 Federal PSD permit was an update to the original Federal PSD permit for the Bonanza plant, issued in February of 1981. The 2001 permit was not intended to authorize a particular construction project, but rather to consolidate into one enforceable document the emission limitations and other requirements that had been established for this facility in a series of permitting actions over several years.[15] As discussed in section IV and below, in the intervening years, the State of Utah issued a permit to Deseret Power for Bonanza in 1998, regarding the ruggedized rotor project. Subsequently, EPA determined that the State did not have authority to issue the 1998 permit. On September 22, 1999, EPA wrote to Deseret Power to explain that EPA was the CAA permitting authority since the Bonanza plant is in Indian country within the Uintah and Ouray Reservation, and that EPA must therefore issue an updated Federal PSD permit.

As stated in the record supporting the 2001 Federal PSD permit, EPA’s 2001 PSD

[15] Page 2 of the Fact Sheet for the 2001 PSD permit, dated September 12, 2000, says “The reason for EPA’s reissuance of this Permit is that the Permittee is located in Indian country. … This Permit replaces State issued Approval Orders.”

action relied on “analyses of information made available to the State of Utah” in issuing permits (otherwise referred to as Approval Orders) to the facility.[16] These analyses included the State’s “Modified Source Plan Review” (MSPR) dated January 2, 1998, for an Approval Order issued on March 16, 1998. The “Emissions Summary” in the MSPR indicated that the “current emissions” of NO_x at Bonanza plant are 10,558 tons per year (tpy), and the “total allowable” NO_x emissions are 10,030 tpy, the difference being an “emission change” of negative 528 tpy (i.e., an emission reduction). The MSPR did not indicate how these emission figures were calculated.

EPA’s 2001 PSD action erred in not conducting a full independent review of the rationale for the MSPR. As stated above, EPA relied instead “on the analyses of information made available to the State of Utah in issuing [permits],”[17] which included the State and permittee’s data from the 1998 State action. EPA has since conducted an independent analysis (discussed further below) and found that the maximum actual pre-project NO_x emissions, as reported by Deseret to EPA in September of 2005, were approximately 7,005 tpy, much less than 10,558 tpy. The record shows the MSPR evaluation of emissions increases for the project, and its conclusion that the emissions increase was not significant, failed to use actual pre-project emissions as the baseline for determining the amount of increase. Since the PSD rules in effect in 2001, when EPA re-issued the federal PSD permit, require PSD applicability to be determined from a comparison of actual pre-project emissions to either the post-project actual emissions or the post-project potential emissions, EPA has reached a preliminary determination that

[16] Federal PSD permit reissuance by US EPA Region 8 for Deseret Power’s Bonanza power plant, PSD-UO-0001-2001:00, February 2, 2001,
[17] Id.

the 2001 PSD permit decision incorporating the rationale of the MSPR was defective, by failing to use actual pre-project emissions as the baseline for determining whether the proposed project would constitute a major modification for NO_x and trigger PSD review. Further, data on actual pre-project and post-project emissions, also reported by Deseret to EPA, appear to show that a significant net emission increase for NO_x occurred.

Thus, EPA has preliminarily determined that the Federal PSD permit issued in 2001 failed to apply the PSD regulations correctly because EPA relied on a faulty analysis conducted by the State and did not conduct a complete, independent analysis of whether the ruggedized rotor project was subject to PSD review based on the regulations in place at that time and whether a revision of the emission limits in the 1981 Federal PSD permit for the Bonanza plant was appropriate. We now recognize our error and, as noted previously in this document, EPA will undertake a separate error correction PSD permitting action in the near future that will undergo its own public notice and comment period. However, as part of the current Title V permitting action, EPA is proposing terms and conditions in the draft Title V permit requiring Deseret to request an administrative permit amendment to revise the Part 71 permit to incorporate the terms of the final and effective Federal PSD permit correction for this facility, shortly after the PSD permit correction process is completed. *See* Draft Permit, Section III.D. “Compliance Schedule and Progress [40 CFR 71.6(c)(3) and (4); 71.5(c)(8)(iii)].”

PSD rules allow for an actual emissions evaluation. As explained below, when pre-project actual emissions are compared to post-project actual emissions for determining PSD applicability, Continuous Emission Monitoring System (CEMS) data reported to EPA for the Bonanza plant reveal that the ruggedized rotor project caused a significant net increase in actual NO_x emissions; and therefore, EPA has made a preliminary determination that the 2001 PSD permit action should have included PSD major modification review for Deseret's ruggedized rotor project.

EPA's 2003 Request to Deseret and Analysis of Deseret's Response

In response to comments from NPS on the August 2002 draft title V permit, EPA analyzed the question of PSD applicability for the ruggedized rotor project. EPA contacted Deseret Power by phone in late 2002 and asked for submittal of a comparison of pre-project actual emissions to post-project actual emissions for all PSD pollutants. Deseret Power responded by letter on February 26, 2003, attaching an Excel spreadsheet with PM_{10}, SO_2, NO_x and CO emissions data from January 1995 through December 2002.[18] EPA reviewed Deseret Power's February 2003 response, and on September 8, 2003, EPA Region 8 sent a follow-up inquiry letter to Deseret Power, to ask for information on: (1) any "contemporaneous" plant changes; (2) emission increases of any PSD pollutants not already included on the February 2003 Excel spreadsheet; and (3) the basis for PM_{10} emission factors used in the spreadsheet.[19] Deseret Power responded on December 29, 2003 with the requested information.[20]

Pursuant to Federal PSD rules in effect at the time EPA issued the 2001 PSD permit, under the definition of "actual emissions" at 40 C.F.R. § 52.21(b)(21)(v), electric utilities that use an actual-to-projected-actual emission comparison to demonstrate PSD

[18] Letter and attachment dated February 26, 2003, from David Crabtree, Vice President and General Counsel, Deseret Power Electric Cooperative, to Richard R. Long, Director, Air & Radiation Program, U.S. EPA Region 8.
[19] Letter dated September 8, 2003, from Richard R. Long, Director, Air & Radiation Program, U.S. EPA Region 8, to David Crabtree, Vice President and General Counsel, Deseret Power Electric Cooperative.
[20] Letter dated December 29, 2003, from David Crabtree, Vice President and General Counsel, Deseret Power Electric Cooperative, to Richard R. Long, Director, Air & Radiation Program, U.S. EPA Region 8.

non-applicability are required to submit post-project annual emissions reports for a period of at least five years following resumption of regular operations after the project. Deseret Power began submitting these reports in 2003, submitting the final report for the five-year post-project period on September 21, 2005.[21]

On September 27, 2005, Deseret Power provided an explanation of its calculation methodology for PSD applicability.[22] Deseret's explanation attempted to show that PSD was not triggered for the 2000 ruggedized rotor project. Although EPA has no information to indicate that Deseret Power projected the future actual emissions in advance of the 2000 ruggedized rotor project, the September 2005 explanation relied on the definition of "Representative actual annual emissions" at 40 C.F.R. § 52.21(b)(33) in the PSD rules that were in effect at the time of the project. Under that definition, the projection of future actual emissions shall be:

> [T]he average rate, in tons per year, at which the source is projected to emit a pollutant for the two-year period after a physical change or change in the method of operation of a unit, (or a different consecutive two-year period within 10 years after that change, where the Administrator determines that such period is more representative of normal source operations).

Further, at §52.21(b)(33)(ii), the definition says the projection shall:

> <u>Exclude</u>, in calculating any increase in emissions that results from the particular physical change or change in the method of operation at an electric utility steam generating unit, <u>that portion of the unit's emissions</u> following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit <u>that is unrelated to the particular change</u>, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole. (emphasis added)

[21] Excel spreadsheet dated September 21, 2005, transmitted via email from Howard Vickers of Deseret Power to Mike Owens of EPA.

[22] Email dated September 27, 2005, with attachment consisting of an undated letter, from Howard Vickers of Deseret Power to Mike Owens of EPA.

It is critical to the proper implementation of the PSD program that the calculation of the representative actual annual emissions be made prior to the project, so that the correct amount of excluded emissions can be considered in reviewing the post-project emissions that are reported. In its September 27, 2005 letter to EPA, Deseret Power did not present a pre-project calculation. Instead, Deseret interpreted the regulations and associated preambles to allow two types of adjustments to be made to the post-project emissions data. Deseret's first adjustment subtracted post-project emissions that were claimed to be "directly related to demand growth." Deseret's second adjustment subtracted "emissions that could have been accommodated" by the unit during the baseline period from the post-project emissions data. As explained below, there are fundamental flaws, not only with both of Deseret's adjustments, but also with Deseret's interpretation that post-project emissions can be adjusted at all. EPA has made a preliminary determination that the analysis is incorrect.

Deseret's first adjustment, for emissions "directly related to demand growth," relied on the unit's capacity factor (percentage of electricity actually produced compared to the total potential electric production of the unit) and equivalent availability (percentage of electricity the unit was actually available to produce compared to the total potential electricity production of the unit) during the baseline period. Deseret's calculation multiplies a ratio of the maximum baseline equivalent availability and the actual baseline capacity factor times the actual NO_x emission during the selected two-year baseline period. This results in a single value that Deseret subtracted from all NO_x emissions during the post-project period.

In the Wisconsin Electric Power Company (WEPCO) rulemaking that created what is commonly known as the demand growth exclusion, EPA allowed for the exclusion in acknowledgment of the "causation requirement" that the physical and operational change result in the actual emissions increase in order to consider the change to be a major modification.[23] EPA has consistently maintained throughout the WEPCO and the 2002 NSR Reform rulemakings that in order to exclude any emissions under the definition of "representative actual annual emissions," the source must demonstrate that two regulatory requirements are met. First, the source must have been able to legally and physically accommodate the amount excluded in calculating any increase in emissions that results from the particular change or change in the method of operation at the emitting unit. Second, the source must demonstrate that none of the emissions that it could have accommodated are related to the project. Deseret's September 27, 2005 submittal did not demonstrate that any emissions it excluded as "directly related to demand growth" could meet either requirement.

Deseret's analysis of demand growth did not examine the effect the hourly capacity increase of the boiler would have on its emissions during the post-project period. Any emissions resulting from operating the unit at a higher hourly rate than the unit was previously capable of accommodating would be related to the project and not eligible for exclusion. Also, Deseret Power assumed that a uniform amount of emissions was attributable to demand growth for the entire post-project period, without quantifying post-project unit operating conditions or system demand. Without consideration of these post-project factors, Deseret Power's analysis failed to demonstrate the exclusions are

[23] 57 Fed.Reg. at 32326-32328; see also, 67 Fed.Reg. at 80202-80203.

caused by factors unrelated to the project. The analysis incorrectly assumed any unutilized capacity during the baseline period can be quantified and automatically excluded during the post-project period. Emission increases assumed, but not demonstrated, by Deseret Power to be excludable as demand growth may not have been able to have been accommodated and/or may have resulted from the project. Therefore, Deseret's emission adjustments for demand growth cannot necessarily be excluded under 40 C.F.R. § 52.21(b)(33)(ii).

Deseret Power's second uniform adjustment to post-project emissions was for additional emissions that Deseret claimed "could have been accommodated" prior to the project, beyond the emissions that Deseret claimed for exclusion due to "demand growth."[24] Deseret calculated this adjustment by multiplying a ratio of the NO_x emissions rate during the selected 2-year baseline period and maximum 12-month NO_x emissions rate during the 5-year baseline times the actual NO_x emission during the selected two-year baseline period. Like the demand growth adjustment, this results in a single value that Deseret subtracted from all NO_x emissions during the post-project period.

The regulations specify that any emission increases that are excluded from the post-project projection, as unrelated to the project, must be emissions that the unit could have physically and legally achieved.[25] Accordingly, the emissions that the facility

[24] Letter dated September 27, 2005, from Howard Vickers, Environmental Supervisor, Deseret Power Electric Cooperative, to Michael Owens, US EPA Region 8, page 3.
[25] *See* 57 Fed.Reg. at 32,326 ("Under today's rule, during a representative baseline period (see *supra*), the plant must have been able to accommodate the projected demand growth physically and legally even absent the particular change. Increased operations that could not physically and legally be accommodated during the representative baseline period but for the physical or operational change should be considered to result from the change." (Emphasis added)); 67 Fed.Reg. at 80196 ("The adjustments to the projected actual emissions allows you to exclude from your projection ***only*** the amount of the emission increase that is not

"could have accommodated" are a necessary part of the emissions that may be excluded for demand growth, and are not an additional exclusion. The applicability test does not allow a source to count two separate quantities of emissions for exclusion.

Deseret Power's uniform adjustments to all post-project actual emissions were effectively an upward adjustment of the pre-project actual baseline emissions, as they ignored the effect of the project itself on post-project emissions, relied only on operational data and conditions during the baseline period as opposed to post-project operations and conditions, and did not consider or quantify factors that were unrelated to the project for each post-project period evaluated. This point is illustrated by the fact that Deseret's adjustments were the same for each post-project period evaluated, regardless of actual post-project unit operational load, system demand, or quantification or consideration of other potential unrelated factors affecting emissions. Adjustments to the actual baseline emissions are not allowed by the regulations.[26]

As cited above, 40 C.F.R. 52.21(b)(33)(ii) – the regulation in effect at the time of EPA's 2001 permitting action – says that for any portion of the emission increase to qualify for exclusion, it must be unrelated to the particular change. Deseret's methodology for both adjustments in its analysis ignores the regulatory requirement that

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related to the physical or operational change(s). In comparing your projected actual emissions to the unit's baseline actual emissions, you only count emissions increases that will result from the project. For example, as with the electric utility industry, you may be able to attribute a portion of your emissions increase to a growth in demand for your product if you were able to achieve this higher level of production during the consecutive 24-month period you selected to establish the baseline actual emissions, and the increased demand for the product is unrelated to the change." (Emphasis added)).

[26] The definition of "Actual emissions" at 40 C.F.R. §52.21(b)(21) of the PSD rules applicable at the time of the 2001 PSD permit does not provide for any adjustment to the pre-project emissions, whether due to demand growth or any other reason ("[i]n general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operation. … Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period. (emphasis added)). In this instance, the "particular date" is the date that the project occurred, i.e., June of 2000.

emissions cannot be excluded unless they are "unrelated to the particular change." As discussed below, EPA's analysis suggests that the NO_x emission increase was, in fact, related to the "ruggedized rotor" project.

EPA's Analysis of the Relationship between the NO_x Emission Increase and the Project

As explained above, EPA's 2001 PSD action relied on the State's MSPR of January 2, 1998. This was a mistake not only because the EPA erred in not conducting a full independent review of the rationale for the MSPR, but also because at the time that underlying analysis was developed, Utah was not the correct permitting authority. According to the MSPR's description of the ruggedized rotor project, "[b]ecause of the increased capacity of the Turbine Generator to handle steam flow, there will be a net increase in certain emissions resulting from an overall increase in the heat input to the boiler from 4381 MMBtu's/Hr to 4578 MMBtu's/Hr."[27] The information analyzed by EPA demonstrates that a significant portion (if not all) of the post-project emission increase was, in fact, related to the ruggedized rotor project. The following inter-related projects involving the modification of boiler components by June 14, 2000, coincide with the construction of the ruggedized rotor project: (1) coal pulverizer mills were upgraded to substantially higher capacity; [28] (2) burners in the boiler were physically modified to

[27] Excerpt from EPA 2001 PSD Permit Record, Modified Source Plan Review dated January 2, 1998, by the State of Utah for the ruggedized rotor project, page 3. EPA notes that both the actual pre-project and post-project data show these heat input values were substantially exceeded and do not appear to be an accurate representation of actual as-fired maximum heat input capacity or operations at the plant.

[28] Excerpt from EPA 2001 PSD Permit Record, Letter dated November 11, 1999, from Deseret to the State of Utah, on the planned upgrade and rebuild of pulverizers and digital control system for the boiler and turbine. Also letter dated December 17, 1999, from the State of Utah to Deseret, approving the requested changes.

increase burner nozzle tip flow capacity;[29] and (3) modifications were made to the high-pressure/intermediate-pressure and low-pressure sections of the electrical generating turbine to increase capacity.[30] These inter-related projects served to increase the capacity to burn coal and therefore increase the heat input capacity of the boiler.[31] To the extent that the increase in heat input capacity is actually utilized, an increase in NO_x emissions would be expected.

EPA has examined daily actual heat input data on the Bonanza power plant from 1997 through 2005, in an attempt to evaluate the extent to which an increase in actual heat input capacity may have occurred and been utilized as a result of the ruggedized rotor project.[32] Results are presented in Figure 1, at page 52 below. For example, if one compares the pre-project daily actual heat input values with post-project daily actual heat input values, then it appears that actual post-project heat input has, in fact, been in excess of the plant's pre-project capacity.[33] Prior to the project, the maximum actual daily heat input was 116,940 MMBtu, while after the project the maximum actual daily heat input was 142,958 MMBtu. Moreover, following the project, the actual daily heat input exceeded the pre-project maximum of 116,940 MMBtu on most days. When considered

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[29] Excerpt from EPA 2001 PSD Permit Record, Letter dated November 11, 1999, from Deseret to the State of Utah, requesting approval for replacement of boiler barrels and tips of burners. Also Letter dated December 17, 1999, from the State of Utah to Deseret, approving the requested changes.

[30] Excerpt from EPA 2001 PSD Permit Record, Letter dated November 10, 1999 from Deseret to EPA, transmitting information related to the absorber, baghouse, and reliability issues surrounding the turbine. Also the State's Modified Source Plan Review dated January 2, 1998, on the turbine project, as well as the March 16, 1998 permit on the same project.

[31] Heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady-state basis, as determined by the physical design and characteristics of the steam generating unit.

[32] Actual heat input means the actual amount of fuel combustion in a steam generating unit, as measured in terms of thermal energy per unit of time. It relates to the actual amount of fuel burned and the heat content of that fuel.

[33] Daily heat input data obtained from the Air Markets Program Data and based on the procedures found in 40 CFR Part 75, Appendix F. Refer to Figure 1 of this document.

along with the information from the MSPR cited above, the actual heat input values affirm that the project increased the heat input capacity of the boiler and that this additional capacity was utilized after the project. The physical modifications to the boiler and associated equipment, allowing for increased steam production and rate of combustion of coal, also increased the ability of the boiler to emit NO_x. None of the information in Deseret Power's 2005 submittal appears to support a finding that any substantial portion of the post-project emission increase could have been accommodated without the particular change, i.e., without the ruggedized rotor project that occurred in June of 2000, and thus cannot support Deseret's exclusion of those emissions when evaluating PSD applicability.

EPA's Analysis of Five Years' of Pre-Project and Post-Project Emission Data

EPA's examination of five years of pre-project CEMS data and five years of post-project CEMS data for the Bonanza plant, obtained from data reported by Deseret Power to EPA,[34] and presented in Figure 2 of this document, reveals twelve rolling 12-month periods of significant net NO_x emission increases.[35] Based on this information demonstrating a significant net emissions increase in NO_x, EPA proposes to conclude that the project was a "major modification" as defined in 40 C.F.R. §52.21(b)(2) of the PSD rules applicable at the time the 2001 PSD permit was issued,[36] and therefore subject to

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[34] Emissions spreadsheet on Bonanza power plant ("Deseret NPS Cap Fac Adjusted Data.xls"), covering May 1995 through August 2005, submitted via email from Deseret Power to EPA Region 8 on September 21, 2005.

[35] "Significant" in reference to a net emissions increase means a rate of emissions that would equal or exceed the rate of 40 tons per year of nitrogen dioxide. 40 C.F.R. § 52.21(b)(23).

[36] "Major modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to

the requirement at 40 C.F.R. §52.21(i)(1) of those rules to obtain a PSD permit prior to beginning actual construction.

Figure 2, at pages 53-56 below, presents CEMS data covering the period from April of 1995 (five years prior to the project) through June of 2005 (five years after the project). The PSD rules applicable at the time of issuance of the PSD permit in 2001, allowed the actual pre-project emissions baseline to be determined based on the average actual emissions during any two consecutive years preceding the project for electric utility steam generating units.[37] Based on data in Figure 2, the highest single 24-month rolling total of emissions in the five years preceding the project (April 1995 through April 2000), divided by two, yields 7,005 tons per year as the NO_x baseline actual emissions.

Figure 2 also displays the difference between the pre-project actual emissions of 7,005 tons per year and the post-project actual emissions, for each 12-month post-project emissions total. As stated above, that comparison reveals at least twelve rolling 12-month periods of post-project actual NO_x emissions that exceed the pre-project actual emissions by more than the PSD significance threshold of 40 tons per year for NO_x. These twelve periods are highlighted in bold/italics on the table. In fact, from October of 2004 through August of 2005, the significance threshold was exceeded for every consecutive 12-month period. The significant net emissions increases in Figure 2 range between 63 tons per year (for the 12-month period ending in August of 2002) and 734

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regulation under the Act. 40 C.F.R. §52.21(b)(2)

[37]. 57 Fed.Reg. at 32326-32328. "By presumably allowing a utility to use any 2 consecutive years within the past 5, the rule better takes into consideration that electricity demand and resultant utility operations fluctuate in response to various factors such as annual variability in climatic or economic conditions that affect demand, or changes at other plants in the utility system that affect the dispatch of a particular plant. By expanding a baseline for a utility to any consecutive 2 in the last 5 years, these types of fluctuations in operations can be more realistically considered, with the result being a presumptive baseline more closely representative of normal source operation."

tons per year (for the 12-month period ending in August of 2005).

As stated above, EPA's analysis of pre-project and post-project actual emissions at the Bonanza Power plant shows a significant net NO_x emission increase during the entire period from October of 2004 through August of 2005. Deseret's September 21, 2005 emissions spreadsheet and associated letter of explanation dated September 27, 2005 have not provided sufficient justification that these emission increases following the physical changes made in 2000 could have been accommodated during the representative baseline period and are attributable to an increase in projected capacity utilization at Unit 1 that is unrelated to the physical changes made. Therefore, EPA proposes to conclude that the ruggedized rotor project caused a significant net emission increase in actual NO_x emissions during a portion of the five-year post-project reporting period specified in PSD rules and was therefore a major modification requiring PSD review.

Updating the Title V Application and Developing the PSD Correction Permit

In light of the intervening years since the Part 71 permit was initially proposed, in February of 2012, the Region requested an updated Part 71 permit application from Deseret. Deseret submitted the updated application in April of 2012, and provided additional updates as explained elsewhere in this action and included in the docket.

On January 30, 2014, EPA met with Deseret Power and requested information for the PSD BACT NO_x analysis.[38] Deseret responded to EPA's request for the BACT analysis information via email and indicated that it:

> [I]s not currently seeking nor requesting any modification to the PSD Permit conditions issued by EPA and/or other pertinent permit conditions relating to

[38] Memorandum from Deirdre Rothery, to Deseret Title V Docket, Record of Communication – meeting with Deseret (January 30, 2014).

> operations at Bonanza Unit 1. Deseret is currently undertaking to study potential benefits that might reasonably be expected to derive from a potential future project involving additional combustion control at the Bonanza Unit 1. [39]

Deseret Power further explained it would take the Company time to undertake and complete the study.[40] Therefore, on March 26, 2014, EPA Region 8 sent a letter to Deseret Power, requesting specific information pursuant to Section 114 of the Clean Air Act. [41] EPA's letter explained that "[w]e are requesting this information to further inform our [Part 71] permitting process for the Bonanza power plant, including issues regarding Prevention of Significant Deterioration (PSD) applicable requirements and analysis that may be necessary to resolve those issues. Specifically, EPA is planning to address potentially applicable PSD requirements that may have been triggered by Deseret's ruggedized rotor project completed in 2000." The letter requested eight areas of information regarding the existing power plant, as well as information regarding NO_x control technology options for the Unit 1 boiler (e.g., costs, potential control effectiveness, time to install and begin operations); and indicated the information requested in the letter must be submitted within 30 calendar days after receipt of the letter. Deseret Power provided a partial response dated April 17, 2014, stating that an additional 90 days would be needed to complete the response.

This Part 71 Permit and the Related PSD Correction Permit

The Part 71 permit that EPA will issue to Deseret Bonanza must assure

[39] Email from David Crabtree of Deseret Power to Deirdre Rothery of EPA (February 25, 2014).
[40] Id.
[41] Letter from Debra H. Thomas, Acting Assistant Regional Administrator, Office of Partnerships and Regulatory Assistance, EPA Region 8, to Kimball Rasmussen, President and CEO, Deseret Power Electric Cooperative (March 26, 2014).

compliance with all applicable CAA requirements, including PSD requirements that apply to the facility. As explained above, in issuing the 2001 PSD permit, EPA erred in not conducting a full independent review of the rationale for the MSPR. Although the 2001 PSD permit was issued under the authority of EPA's regulations, EPA explicitly stated that it did not perform its own independent analysis. As the analysis herein and supporting record for this action demonstrate, EPA has made a preliminary determination that there is deficiency in the PSD permitting process, namely that the 2000 ruggedized rotor project should have undergone PSD review for NO_x, including a BACT analysis. Therefore, the emission limits in the 2001 PSD permit do not represent the outcome of a required BACT determination.

EPA is undertaking a separate and forthcoming PSD correction permitting action and the draft Title V Permit requires that Deseret take action to incorporate any new PSD terms finalized in that action into the Part 71 permit at the completion of the PSD process. In the PSD correction permitting action, EPA plans to address the PSD requirements by performing a retrospective BACT analysis that should have been conducted prior to construction of the ruggedized rotor project, and proposing to issue a revised NO_x emission limitation that reflects that BACT analysis. EPA intends to provide notice and opportunity to comment on the proposed PSD permit action in accordance with the requirements of 40 C.F.R. part 124. The revised PSD terms and conditions would then be added to this Part 71 permit at a later time, as required by condition III.D. of this proposed permit. *See* Draft Permit, Section III.D. "Compliance Schedule and Progress [40 CFR 71.6(c)(3) and (4); 71.5(c)(8)(iii)]."

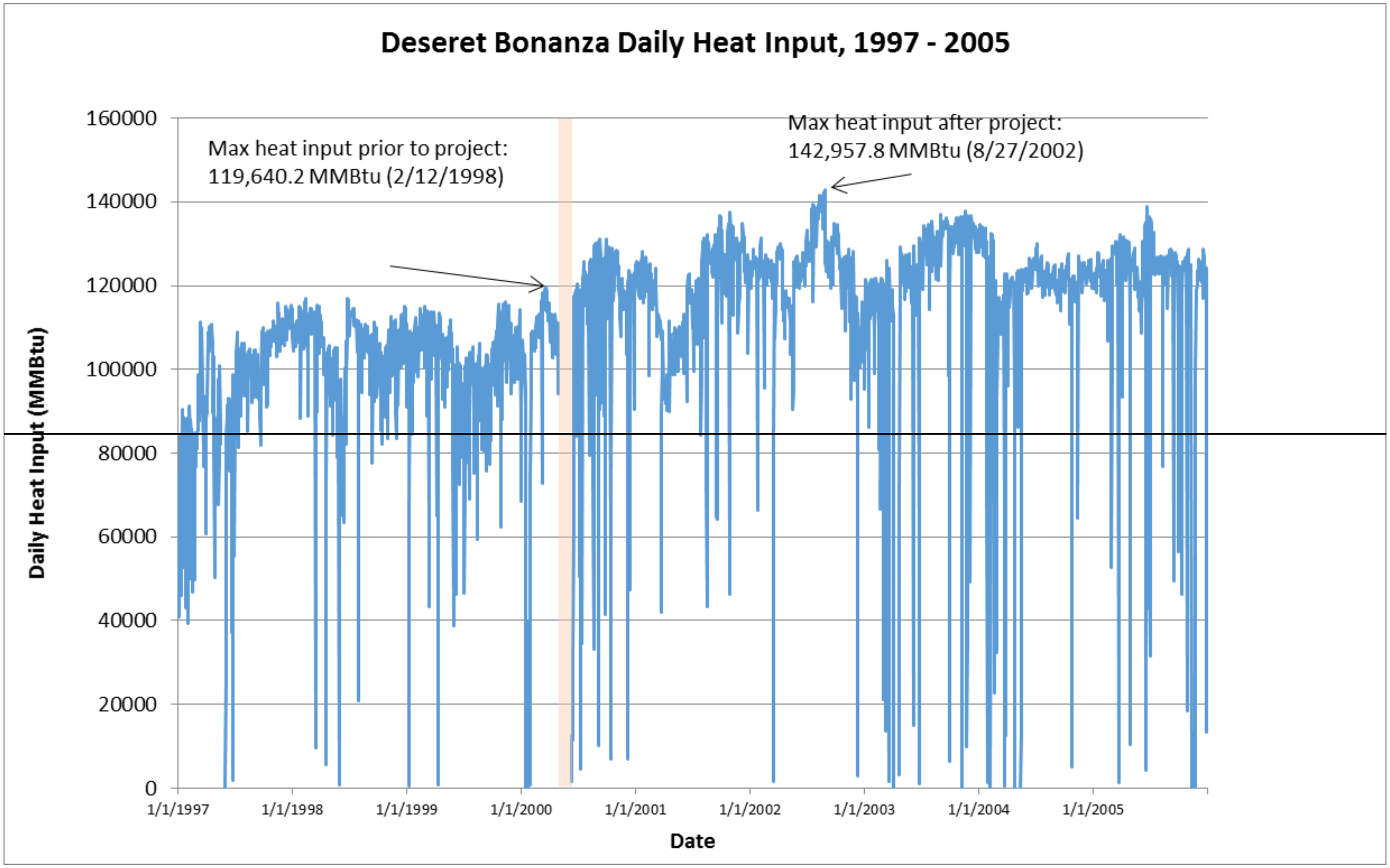
As noted before, emission limits originating in a previously-issued PSD permit cannot be revised in a Title V permit without first (or simultaneously) revising the PSD permit under the applicable PSD regulations.

Proposed Conclusion and Related Title V Permit Terms and Conditions

As discussed in the analysis above and in accordance with Title V and PSD permitting requirements, EPA proposes conditions in the Part 71 permit that provide for amending the Title V permit so that Deseret's Part 71 permit will contain all applicable requirements including those issued in the PSD correction permit. Specifically, proposed permit condition III.D. requires the following:

1. <u>Request for Administrative Permit Amendment:</u> Within 60 days after EPA issues a final and effective Federal PSD permit correction for this facility, the permittee shall submit to EPA a request for an administrative permit amendment to revise the Part 71 permit to include the terms and conditions of the PSD permit correction. [Section IV. H of this permit; 40 CFR 71.7(d)]

Figure 1.[42]



[42] Data retrieved from the EPA Air Markets Program Data on March 27, 2014. Complete data set available in the docket.

Figure 2. PSD Applicability Test
Deseret Power
Emissions Data – Bonanza Unit 1
Date of Physical/Operational Change (May 2000)

BASELINE DATA:

Month	NOx Monthly (Tons)	NOx Rolling 24-Month/2 (Tons)
May-95	119.8	
Jun-95	5.7	
Jul-95	407.8	
Aug-95	694.6	
Sep-95	635.4	
Oct-95	589.3	
Nov-95	505.2	
Dec-95	328.7	
Jan-96	490.0	
Feb-96	431.8	
Mar-96	364.0	
Apr-96	441.2	
May-96	342.4	
Jun-96	518.7	
Jul-96	720.0	
Aug-96	947.3	
Sep-96	826.5	
Oct-96	701.3	
Nov-96	736.3	
Dec-96	642.8	
Jan-97	452.2	
Feb-97	431.8	
Mar-97	637.7	
Apr-97	705.9	6338.2
May-97	308.5	6432.6
Jun-97	323.6	6591.5
Jul-97	458.8	6617.0
Aug-97	527.4	6533.4
Sep-97	461.0	6446.2
Oct-97	496.6	6399.9
Nov-97	576.7	6435.6

Dec-97	647.5	6595.0	
Jan-98	620.6	6660.3	
Feb-98	640.9	6764.9	
Mar-98	593.3	6879.5	
Apr-98	519.8	6918.8	
May-98	515.7	**7005.5**	**Maximum consecutive 24 months (expressed as annual tons)**
Jun-98	444.0	6968.1	
Jul-98	583.9	6900.1	
Aug-98	596.5	6724.7	
Sep-98	534.1	6578.5	
Oct-98	497.0	6476.3	
Nov-98	581.2	6398.8	
Dec-98	630.6	6392.7	
Jan-99	475.1	6404.1	
Feb-99	500.0	6438.2	
Mar-99	500.8	6369.8	
Apr-99	483.8	6258.7	
May-99	552.2	6380.6	
Jun-99	385.5	6411.5	
Jul-99	396.9	6380.6	
Aug-99	411.1	6322.4	
Sep-99	440.7	6312.3	
Oct-99	505.9	6316.9	
Nov-99	498.6	6277.9	
Dec-99	481.8	6195.0	
Jan-00	216.0	5992.7	
Feb-00	495.3	5919.9	
Mar-00	552.5	5899.5	
Apr-00	386.8	5833.0	

<u>POST-CHANGE DATA:</u>

Month	NOx Monthly (Tons)	NOx Tons Rolling 24-Month/2 (Tons)	NOx Increase Over Baseline (Tons/Year)	PSD Significant Increase? (Y/N)
Sep-00	590.9			
Oct-00	655.6			
Nov-00	655.1			
Dec-00	525.8			
Jan-01	625.5			
Feb-01	551.5			
Mar-01	551.3			
Apr-01	540.7			
May-01	579.4			
Jun-01	592.2			
Jul-01	574.2			
Aug-01	621.7			
Sep-01	616.1			
Oct-01	563.5			
Nov-01	540.4			
Dec-01	626.9			
Jan-02	620.8			
Feb-02	553.4			
Mar-02	558.1			
Apr-02	615.0			
May-02	572.2			
Jun-02	559.0			
Jul-02	595.3			
Aug-02	653.0	7,068.9	***63.4***	***Y***
Sep-02	539.4	7,043.1	37.7	N
Oct-02	473.9	6,952.3	-53.2	N
Nov-02	466.0	6,857.7	-147.8	N
Dec-02	470.0	6,829.8	-175.7	N
Jan-03	551.5	6,792.8	-212.7	N
Feb-03	475.6	6,754.9	-250.6	N
Mar-03	464.8	6,711.6	-293.9	N
Apr-03	264.1	6,573.3	-432.2	N
May-03	790.1	6,678.6	-326.8	N
Jun-03	498.7	6,631.9	-373.6	N
Jul-03	628.4	6,659.0	-346.5	N

Aug-03	733.0	6,714.6	-290.9	N
Sep-03	694.6	6,753.8	-251.6	N
Oct-03	751.3	6,847.7	-157.8	N
Nov-03	631.9	6,893.4	-112.0	N
Dec-03	718.8	6,939.4	-66.1	N
Jan-04	698.4	6,978.2	-27.2	N
Feb-04	521.0	6,962.0	-43.5	N
Mar-04	612.3	6,989.1	-16.4	N
Apr-04	527.3	6,945.2	-60.2	N
May-04	459.2	6,888.7	-116.7	N
Jun-04	651.1	6,934.8	-70.7	N
Jul-04	642.2	6,958.3	-47.2	N
Aug-04	607.1	6,935.3	-70.1	N
Sep-04	660.7	6,995.9	-9.5	N
Oct-04	652.0	7,085.0	***79.6***	***Y***
Nov-04	630.4	7,167.3	***161.8***	***Y***
Dec-04	688.5	7,276.5	***271.0***	***Y***
Jan-05	723.4	7,362.4	***357.0***	***Y***
Feb-05	600.7	7,425.0	***419.5***	***Y***
Mar-05	721.3	7,553.2	***547.8***	***Y***
Apr-05	637.2	7,739.8	***734.3***	***Y***
May-05	615.6	7,652.5	***647.1***	***Y***
Jun-05	562.6	7,684.5	***679.0***	***Y***
Jul-05	659.3	7,699.9	***694.4***	***Y***
Aug-05	639.0	7,652.9	***647.4***	***Y***