June 16, 2014

Via E-Mail

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Re: Sierra Club's Comments on Bonanza Power Plant Draft Title V Operating Permit

Dear Mr. Owens:

Please accept these comments regarding Deseret Power Electric Cooperative's Bonanza Power Plant, located in Uintah County in northeastern Utah.

The Bonanza plant is a 500 megawatt coal-fired electric utility boiler constructed in 1984 with the potential to emit approximately 9,228 tons per year (tpy) of nitrogen oxides (NO_X), 1,968 tpy of sulfur dioxide (SO_2), 574 tpy of particulate matter (PM), and 68 tpy of Hazardous Air Pollutants (HAPs). The Bonanza plant is located on the Uintah and Ouray Indian Reservations, where EPA has jurisdiction to administer the Clean Air Act permitting program. EPA has never issued Bonanza a Title V permit to operate.

The Sierra Club is the oldest and largest grassroots environmental group in the United States, with approximately 625,000 members nationally, including 3,905 members in Utah. Sierra Club is dedicated to exploring, enjoying, and protecting the wild places of the earth; to practicing and promoting the responsible use of the earth's ecosystems and resources; to educating and enlisting humanity to protect and restore the quality of the natural and human environment; and to using all lawful means to carry out these objectives.

A Title V permit must include all operational requirements and limitations to ensure compliance with all applicable requirements. 40 C.F.R. § 71.6(a)(1). Applicable requirements include the obligation to obtain a Prevention of Significant Deterioration (PSD) permit, Best Available Control Technology (BACT) emission limits, and limits necessary to ensure protection of air quality standards and increments. 40 C.F.R. § 71.2 ("*Applicable requirement* means… (1) Any

standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA through rulemaking under title I of the Act that implements the relevant requirements of the Act, including any revisions to that plan promulgated in part 52 of this chapter…"); *In re Columbia Generating Station*, Petition No. V-2008-1, Order at 3 (EPA Adm'r, Oct. 8, 2009); Statement of Basis (SOB) at 29.

The fact that EPA issued a PSD permit for Bonanza in 2001 in error does not affect the obligation to correctly determine PSD applicability in the current Part 71 permit. *In re Duke Energy Indiana Edwardsport Generating Station,* Permit No. T083-271 38-00003 (Dec. 13, 2011) at 3 (a previously issued PSD permit that does not meet the requirements of 40 C.F.R. § 52.21 means that the current, pending, Title V permit is not in compliance with all "applicable requirements.") Thus, to the extent that EPA intends to postpone a determination of whether the 2000 ruggedized rotor, pulverizer, and burner modifications[1] trigger BACT and air impact PSD obligations, SOB at 9 (suggesting that a future proceeding will address "PSD requirements that might have been triggered"), EPA's proposal conflicts with its obligation to make the applicability determination in the Part 71 permit.

I. The PSD Program, Including BACT Limits and Limits to Ensure Air Quality Protections, Are Applicable Requirements Triggered by the 2000 Ruggedized Rotor Major Modification and Must Be Included in the Final Permit.

PSD program requirements (including BACT limits and the obligation to establish limits protective of NAAQS and increments[2]) are applicable requirements for NO_X, SO_2, and particulate matter. EPA's analysis concludes that the ruggedized turbine project was a major modification for NO_X, and therefore triggered PSD requirements for at least that pollutant. While EPA is correct that the project was a major modification for NO_X, EPA's analysis is incomplete and in some ways erroneous. Applying the correct analysis to the 2000 ruggedized rotor project shows that it was a major modification for particulate matter ($PM_{2.5}$ and PM_{10}), sulfur dioxide and nitrogen oxides.

[1] These projects will be referred to herein, individually and collectively, as the ruggedized rotor project.

[2] The SOB notes that EPA will undertake a PSD permitting action that will include a determination of whether revisions to the emission limits from the 1981 permit are necessary. SOB at 36. A new PSD permit must also contain an analysis of ambient air quality impacts and increment consumption. 40 C.F.R. § 52.21(k). And because the 2000 ruggedized rotor modification constitutes "construction" of a major modification after the major source baseline date for SO_2, NO_X and particulate matter, the plant's actual emissions as defined in 40 C.F.R. § 52.21(b)(21), must be considered increment consuming. 40 C.F.R. § 52.21(b)(13)(ii)(a), (b)(14)(i).

EPA concludes that if the applicant complied with the requisite reporting obligations for all years and qualified for the "representative actual emission" applicability procedure set forth in 40 C.F.R. §§ 52.21(b)(2)(i), (b)(3)(i)(a), (b)(21)(v), and (b)(33) (1992-2003), post project emissions show an increase in NO_X above the significance threshold of 40 tons. SOB at 45-48. EPA's analysis skips the critical steps of determining the representative actual emissions at the time of the ruggedized rotor replacement.

In the SOB, EPA incorrectly summarizes the standard for determining whether a project constitutes a major modification ("PSD applicability") as involving a determination based on "a comparison of actual pre-project emissions to either the post-project actual emissions or the post-project potential emissions," SOB at 35, and comparing "pre-project actual emissions… to post-project actual emissions…" SOB at 36. This could be misinterpreted as saying that PSD applicability can be determined based on an actual-to-confirmed-actual basis—which waits until a project has occurred and subtracts pre-project emissions from measured post project emissions. EPA should clarify the SOB to prevent such misinterpretations.[3]

As EPA is well aware, the test for PSD applicability is not a comparison of pre-project baseline emissions to post-project confirmed-actual emissions. *See e.g., U.S. v. Ohio Edison Co.*, 276 F.Supp.2d 829, 881 (S.D.Ohio 2003) (the statute is "abundantly clear that PSD applicability is to be determined prior to the commencement of a project."); 57 Fed. Reg. 32,314, 32,323 (July 21, 1992) (describing factors included in a projection), *id*. at 32,316 (applicability must be determined prior to construction). Post-project emission reporting and analysis is a back-stop to make sure that the pre-project projections do not miss an increase that occurs despite a projection that it would not occur; the post project data are not to serve as a replacement for a pre-project projection. *New York v. EPA*, 413 F.3d 3, 34 (D.C. Cir. 2005) (describing the 1992 WEPCO Rule revisions to 40 C.F.R. § 52.21 as requiring "utilities whose *projections* included no significant emissions increase" from a modification "to supply permitting authorities with a minimum of five years of data to verify the projections' accuracy." (emphasis added)); *Ohio Edison*, 276 F.Supp.2d at 875 (rejecting interpretation of PSD that would use post-project emission data to determine applicability); 57 Fed. Reg. at 32,325 (explaining that the reporting is a backstop to ensure that emissions do not unexpectedly increase):

> Any other construction of the Act and its regulations would turn the preconstruction permitting program on its head and would allow sources to construct without a permit while they wait and see if it would be proven that emissions would increase. Clearly, Congress did not intend such an outcome, which would eviscerate

[3] The SOB is also clear that the correct analysis is an "actual-to –projected-actual emission comparison" as long as post-project reporting is done. SOB at 37-38.

> the preconstruction dimension of the program. Thus, the Court concludes that the issue of whether [the utility's] projects required a [PSD] permit must be determined by reviewing evidence of the projected post-project emissions increases, and not by reviewing evidence of the actual post-project emissions data.

United States v. S. Ind. Gas & Elec. Co., Case IP99-1692-C-M/F (S.D.Ind. July 18, 2002); *see also* Brief of the United States In Support of Its Motion for Summary Judgment and Declaratory Relief at 25-29, *U.S. v. Oklahoma Gas & Elec. Co*., Civ. Action No. 5:13-cv-690-D (Doc. #8-1) (Aug. 30, 2013) ("the recordkeeping and reporting requirements in no way altered or replaced the forward-looking requirements that have always been the cornerstone of the PSD program").

Applying the correct test for PSD applicability shows that the 2000 ruggedized rotor project was a major modification for SO_2, NO_X and PM (including PM, PM_{10} and $PM_{2.5}$).

First, as a preliminary matter, the so-called actual-to-projected-actual test is only available under the rules in effect at the time of the 2000 project (and under the rules currently in effect) if—and only if — certain predicate reporting obligations are met. 40 C.F.R. § 52.21(b)(21)(v) (1993-2002); 57 Fed. Reg. at 32,324-32,325 ("any utility which utilizes the 'representative actual annual emissions' methodology to determine that it is not subject to NSR must submit for 5 years after the change sufficient records to determine if the change results in an increase in representative actual annual emissions."). Post-project reports must be filed every year for at least the first five years. 40 C.F.R. § 52.21(b)(21)(v) (1992-2003); 72 Fed. Reg. 10,445, 10,447 (March 8, 2007). Here, it is clear that the plant failed to do so for the first two years. SOB at 38 (noting that reports were first filed in 2003). Therefore, the plant cannot qualify for the projected-actual test and, by default, opted to use the actual-to-potential test. *See e.g*., Pls. Mem. Supp. Partial Sum. J. at 35 and n.14, *U.S. v. Duke Energy*, Case No. 1:00-cv-1262 (M.D.N.C., filed 1/31/03) (noting that the "actual-to-potential" test applies because Duke failed to satisfy the WEPCO rule's reporting requirements); Initial Brief of the United States Environmental Protection Agency Enforcement 39-41, *In re Tennessee Valley Authority*, Case No. CAA-2000-04-008 (EAB) (explaining that the "rule enables post modification actual emissions to be determined by projecting the "representative actual annual emissions" of the unit… [However] the rule by its terms is provisional; a source may use the methodology *only if it submits* "on an annual basis, for a period of at least 5 years from the date the unit resumes regular operations, information demonstrating that the physical or operational change did not result in an emissions increase…"); Reply Brief of the United States Environmental Protection Agency Enforcement 56-57, *In re Tennessee Valley Authority*, Case No. CAA-2000-04-008

(explaining that EPA's 1992 WEPCO rule "made an actual-to-projected-actual test available to such changes, but only when two prerequisites were satisfied..." including that "the rules themselves are expressly provisional, applying only where sources submit sufficient pre- and post-change emissions information to enable the permitting authority to calculate whether emissions would increase from the change.")

An application of the actual-to-potential test shows significant net emission increases of SO_2, NO_X and PM (including PM, PM_{10} and $PM_{2.5}$). Below are the highest pre-project emissions compared to the post project potential to emit.

Pollutant	Pre-project two year (Jan.-Dec) annual average actual emissions (TPY) [4]	Post-project potential to emit actual emissions (TPY)[5]	Difference/Increase (TPY)
SO_2	1354	1968	614
NO_X	6495	9228	2733
PM_{10}	503	574	71[6]

These increases are "significant," 40 C.F.R. § 52.21(b)(23)(i), and therefore trigger PSD program "applicable requirements."[7]

Second, even if the facility *had* done a pre-project projection of post-project emissions, and had complied with the mandatory reporting obligations associated with such a test during all five

[4] 24-month rolling averages can also be used and result in slightly different baselines, but do not change the resulting projected emission increase values or the conclusion that the project was major for these three pollutants.

[5] *See* SOB at 5.

[6] Most, if not all, of this increase is also $PM_{2.5}$. Because $PM_{2.5}$ was a "pollutant subject to regulation" after the 1997 $PM_{2.5}$ NAAQS, and no "significant" rate was included in 40 C.F.R. § 52.21(b)(23)(i) at the time of the ruggedized rotor project, the significance threshold was "any emission rate." 40 C.F.R. § 5§ 52.21(b)(23)(ii) (2000). Therefore, the project was significant for $PM_{2.5}$ as well.

[7] There have been no contemporaneous and creditable increases or decreases identified by the facility, EPA or through our independent review. *See, e.g.*, SOB at 37 n.19. Therefore, the increase in "actual emissions" are the full "net emissions increase." 40 C.F.R. § 52.21(b)(3)(i) (1992-2002). While some other changes to pollution controls were made at the plant around the same time as the 2000 ruggedized rotor project, any associated reductions are not "creditable" because they were not enforceable. 40 C.F.R. § 52.21(b)(3)(vi)(b). The only enforceable emission limits within the contemporaneous period were higher than the pre-project actual emissions and, therefore, do not provide creditable decreases.

post-project years, the required projection shows a significant net emissions increase of SO_2, NO_X and PM (including PM, PM_{10} and $PM_{2.5}$). According to the facility's permit application for the project, the heat input capacity of the boiler would increase from 4,381 to 4,578 MMBtu/hour (a 197 MMBtu/hr increase). At even a low 75% capacity factor (which is conservatively low, compared to the plant's actual and expected capacity factor[8]), the resulting projected increase in heat input following the project would be 1,294,290 MMBtu/year. Applying the pre-project lb/MMBtu emission rates to this annual heat input increase attributable directly to the project would result in significant net emission increases[9] of at least the following (and likely much higher due to the plant's actual higher capacity factor).

Pollutant	Increase In Heat Input	Annual Increase In Heat Input[10]	Emission Factor (lb/MMBtu)	Difference/Increase (TPY)
SO_2	197 MMBtu/hour	1,294,290 MMBtu/year	0.084	54
NO_X	197 MMBtu/hour	1,294,290 MMBtu/year	0.372	240
PM_{10}	197 MMBtu/hour	1,294,290 MMBtu/year	0.0286	18[11]

Because these increases are directly attributable to the increased heat input to the boiler caused by the project, and were not capable of accommodation prior to the project, there is no basis to exclude any amount of the increase due to "load growth," or any other basis. *See* SOB at 38-40. While the post-project emissions data show that NO_X emissions increased as a result of the project, SOB at 45-55, those findings would be relevant if an actual-to-projected-actual test had predicted no increase but "WEPCO Rule backstop reporting" showed that increased actually did occur. In that case, the facility would be subject to PSD applicable requirements despite a pre-project projection that emissions would not increase. However, here, a pre-project projection indicates expected increases in NO_X, SO_2 and particulate matter.

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[8] *See* September 27, 2005, Deseret Letter to EPA at p. 2 (noting that monthly capacity factors averaged 86.3% prior to the project and 94.6% after the project). Using these capacity factors instead would result in even larger projections of representative actual (*i.e.*, post-project projected) emissions.

[9] As noted above, there were not creditable emission decreases, so the net emissions increase is at least as high—or higher—than the increase in actual emissions.

[10] 197 MMBtu/hour increase * 8760 hours/year * 0.75 (capacity factor) = 1,294,290 MMbtu/year increase.

[11] Again, because most or all of these increases are also $PM_{2.5}$, and the threshold for a significant increase of $PM_{2.5}$ at the time of the project was "any increase," this also represents a significant net emissions increase of $PM_{2.5}$.

II. The Compliance Schedule Does Not Satisfy the Requirements for Such a Schedule.

Not until all steps are taken to incorporate BACT emission limits and any additional limits required to ensure protection of NAAQS and increments will the plant be in compliance with all applicable requirements. To the extent that EPA decides to ensure compliance through a compliance schedule, rather than immediately upon permit issuance, the compliance schedule must conform to the Clean Air Act and Part 71. The compliance schedule in the draft permit fails to do so.

Pursuant to 42 U.S.C. § 7661(3), a "schedule of compliance (which is required in the permit pursuant to 42 U.S.C. § 7661c(a)) must "includ[e] an enforceable sequence of actions or operations, leading to compliance with an applicable implementation plan, emission, standard, emission limitation, or emission prohibition." That is, the steps required must be sufficient to lead to compliance—not merely lead part way to compliance but omit the additional steps that would ultimately result in compliance.

The implementing regulations similarly require a compliance schedule, 40 C.F.R. § 71.6(c), which must comply with the following:

> (C) A schedule of compliance for sources that are not in compliance with all applicable requirements at the time of permit issuance. Such a schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones*, leading to compliance with any applicable requirements for which the source will be in noncompliance at the time of permit issuance*. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based.

40 C.F.R. § 71.5(c)(8)(iii). Like the statute, the implementing regulation also requires that the schedule contain all steps necessary to "lead to compliance" and not merely contain some steps but omit others that are necessary to bring the plant into compliance.

The compliance schedule in the draft permit-- Condition § III.D.1—provides as follows:

> 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)]

This provision only requires the permittee to submit a request for a permit amendment. It fails to:

- Require that such application seek to include PSD applicable requirements, including BACT emission limits, limits to protect NAAQS, and limits to ensure that the increments are protected.
- Require the permittee to supplement the application if it fails to satisfy the requirements of 40 C.F.R. § 52.21 or fails to request the necessary limits.
- Require that the permittee ever obtain a PSD permit that contains the necessary limits[12]
- Require the facility to install any necessary pollution controls to meet the limits
- Require the facility to ultimately comply with BACT limits
- Require any "enforceable sequence" of actions or deadlines for the above-mentioned items

Because the draft permit's compliance schedule fails to contain each step necessary to lead to compliance as an enforceable condition, it fails to meet the requirements for a compliance schedule in the Act and in Part 71.

III. EPA's Compliance Monitoring Required by 40 C.F.R. § 71.6(c)(1) Should Include the Particulate Matter Continuous Emissions Monitoring System (PM CEMS).

EPA requires PM CEMS to be used for Compliance Assurance Monitoring (40 C.F.R. pt. 64), but not as reasonable assurance of compliance monitoring pursuant to 40 C.F.R. § 71.6(c)(1). There is no apparent basis for this distinction. PM CEMS are capable of providing continuous emissions data to determine compliance—whereas the performance tests required in the permit occur very infrequently, with prior notice, and at ideal conditions, which provides very little if any data capable of demonstrating that the plant complied with permit limits during the vast majority of time when no stack testing is being performed. That is, EPA does not provide a basis for a finding that infrequent stack tests are sufficient to "assure compliance" with particulate matter permit limits at all times and during all operating conditions, as required by 40 C.F.R. § 71.6(c)(1). Since PM CEMS are already being required, (Draft Permit at p. 63, Condition 6(a)(viii)(B)), they should also be used to satisfy § 71.6(c)(1).

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[12] Contrary to the SOB's description of the compliance schedule, the draft permit does not "require[]" that "revised PSD terms and conditions would… be added to this Part 71 permit at a later time…". SOB at 49.

IV. The Draft Permit Conditions Are Unclear, Ambiguous, and Lack Practical Enforceability

As EPA explained in the preamble to its Title V regulations, "regulations are often written to cover broad source categories," leaving it "unclear which, and how, general regulations apply to a source." EPA, *Operating Permit Program*, 57 Fed. Reg. 32,250, 32,251 (July 21, 1992). Title V permits bridge this gap by "clarify[ing] and mak[ing] more readily enforceable a source's pollution control requirements," including making clear how general regulatory provisions apply to specific sources. S. Rep. 101-228, 1990 USCAAN 3385, 3730 (Dec. 20, 1989). In short, Title V permits are supposed to link general regulatory provisions to a specific source to provide a way "to establish whether a source is in compliance." *Id*.

The draft permit must be sufficiently clear and specific to ensure that all applicable requirements are enforceable as a practical matter. As stated by EPA, the requirement of "practical enforceability" can be described as follows:

> A permit is enforceable as a practical matter (or practically enforceable) if permit conditions establish a clear legal obligation for the source [and] allow compliance to be verified. Providing the source with clear information goes beyond identifying the applicable requirement. It is also important that permit conditions be unambiguous and do not contain language which may intentionally or unintentionally prevent enforcement.

An interested person should be able to understand from the permit how much pollution the plant is legally authorized to emit and how the source is monitored for compliance. Not even a Clean Air Act expert can read Bonanza's draft permit and understand what conditions and emission limits apply at Bonanza. The draft permit contains numerous overlapping, and in some cases, inconsistent standards that govern the same pollutant,[13] it includes many alternatives for compliance, it recites standards verbatim from the regulations without tailoring them to the facility, and it refers to regulations instead of including the applicable emission limits. The draft permit must be revised so that the conditions are clear, specific, and unambiguous.

Although there are many examples in the permit of the above-mentioned issues, Sierra Club focused on the Mercury and Air Toxics Rule (MATS) provisions. EPA should nevertheless review the entire permit and fix similar problems throughout the permit.

EPA should understand how Bonanza intends to comply with the applicable emission limits in the MATS rule, 40 C.F.R. § 63 Subpart UUUUU, and this information should be reflected in the permit. Instead, all of the regulations, each specifying alternative limits and means of

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[13] *E.g.,* Compare (Draft Permit at p. 25, Condition II.A.2(a)(i))(" particulate matter emissions from the main boiler stack shall not exceed 0.030 lb/MMBtu of heat input") with (Draft Permit Condition at p. 61 II.A.6(a)(i))("Particulate matter emissions from the main boiler stack shall not exceed 0.0297 lb/MMBtu of heat input.")

compliance, are incorporated directly into the permit. Moreover, none of the materials explain whether Bonanza will require additional controls in order to meet the MATS limits, and such changes may impact other control technologies.

The draft permit fails to explain which MATS limits apply at Bonanza and how they will be monitored for compliance. It does not specify which of the available alternative emission limits the plant will meet (the filterable PM or the individual metals standards; the SO_2 or the hydrogen chloride (HCL) standard). Instead, the Draft Permit refers to Tables 2, 3, and 4 of Subpart UUUUU and states that the permittee must meet "each operating limit" in those tables "that applies to the EGU at Bonanza plant." (Draft Permit at p.38, Conditions II.A.3(a)(iii)&(iv)). The permit must specify *which* operating limits apply. Additionally, the draft permit and the supporting materials do not specify whether the plant is subject to the "coal-fired unit not low rank virgin coal" or the "coal-fired unit low rank virgin coal" limits in Table 2.

EPA should not include superfluous language or provisions that do not apply to Bonanza. For example, Condition 3(1)(iii) on page 38 of the draft permit incorporates MATS rule language that refers to Section 63.10009, but then includes an explanatory note that 63.10009 is not applicable to Bonanza. EPA should simply delete the reference to 63.10009 to eliminate confusion as well as all other nonapplicable provisions in the permit.

The purpose of the operating permit is to specify exactly which limits apply to a particular source. The Bonanza permit does not fulfill this basic purpose. The permit must include the specific MATS emission limits that apply at the facility and the method to determine compliance. If Bonanza chooses the filterable PM limit instead of the individual non-mercury metal HAPs limits, then the PM CEMS should be used for determining compliance.

Thank you for the opportunity to comment.

Respectfully submitted,

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