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BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF:	)	
	)	
The Clean Air Act Title V Operating Permit	)	PETITION FOR OBJECTION
	)	
For PacifiCorp Hunter Power Plant	)	Permit No. 1500101004
In Castle Dale, Utah	)	Revised: November 19, 2021
	)	In Response to the Administrator's
Prepared by the Utah Division of	)	January 13, 2021 Reopening for Cause
Air Quality	)	

PETITION FOR OBJECTION TO THE TITLE V PERMIT REVISION FOR PACIFICORP'S HUNTER POWER PLANT, PROPOSED FOR ISSUANCE ON OCTOBER 2, 2021 AND FINALIZED ON NOVEMBER 19, 2021, REVISED IN RESPONSE TO JANUARY 13, 2021 ORDER REOPENING THE PERMIT FOR CAUSE

Pursuant to section 505(b)(2) of the Clean Air Act, 42 U.S.C. § 7661d(b)(2), and 40 C.F.R. § 70.8(d), Sierra Club, through its Counsel, George E. Hays, hereby petitions the Administrator of the United States Environmental Protection Agency ("EPA") to object to the revised Title V Operating Permit proposed for issuance by the Utah Division of Air Quality ("UDAQ") for PacifiCorp's Hunter Power Plant on October 2, 2021 and issued as final on November 19, 2021. UDAQ, Revised Title V Operating Permit for PacifiCorp's Hunter Power Plant, Permit No. 1500101004, revised November 19, 2021 (hereinafter "2021 Hunter Title V Permit"), Ex 1.

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INTRODUCTION AND BACKGROUND

The Administrator must object to the 2021 Hunter Title V Permit because, as demonstrated below and in Sierra Club's June 11, 2021 comment letter and associated exhibits,[1] the permit fails to ensure compliance with the applicable prevention of significant deterioration ("PSD") permitting requirements of the Utah State Implementation Plan ("SIP") for projects that were constructed at Units 1, 2, and 3 of the Hunter plant during 1997 to 1999. UDAQ issued the revised Title V Permit for PacifiCorp's Hunter Power Plant in response to EPA's January 13, 2021 Order that reopened the Hunter Power Plant Title V Permit for Cause.[2]

I. PROCEDURAL HISTORY: THIS PETITION AROSE AFTER EPA ORDERED THE 2020 TITLE V PERMIT REOPENED TO CONSIDER PSD APPLICABILITY AT THE HUNTER PLANT.

Previously, on April 11, 2016, Sierra Club filed a petition with EPA to object to the 2016 Hunter Title V renewal permit for, among other things, failure to include applicable requirements of the PSD program for major modifications that were undertaken at the Hunter units in the 1997-1999 timeframe. On October 16, 2017, EPA denied Sierra Club's petition, on grounds that Utah's 1997 Approval Order for the 1997-1999 Hunter modifications established the "applicable requirements" for those projects. Sierra Club appealed that finding and, on July 2, 2020, the U.S. Court of Appeals for the Tenth Circuit ruled in Sierra Club's favor, issuing an opinion vacating the Hunter Order and remanding Sierra Club's petition to EPA for further consideration. *Sierra Club v. U.S. EPA*, 964 F.3d 882 (10th Cir. 2020). Despite the Tenth Circuit decision remanding Sierra Club's 2016 petition back to EPA for consideration, EPA denied Sierra Club's 2016 petition on January 13, 2021. EPA denied Sierra Club's 2016 petition on January 13, 2021

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[1] Sierra Club, Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) with Utah's Response to EPA's January 13, 2021 Reopening for Cause, submitted to UDAQ June 11, 2021 (Ex. 2).

[2] EPA, Order Denying Petitions for Objection to Permits and Reopening Permit for Cause, issued 1/13/2021 (Ex. 3).

because, during the Tenth Circuit proceedings, UDAQ issued a Title V renewal permit for the Hunter Power Plant on September 4, 2020 (nearly six months before the 2016 permit was set to expire), which EPA claimed rendered Sierra Club's 2016 petition moot (because the permit it petitioned EPA to object to was no longer in effect). *Id.* at 10. Sierra Club did also submit a petition to EPA to object to the 2020 Title V renewal permit for the Hunter plant based on the Court's July 2, 2020 decision that found EPA incorrectly interpreted the unambiguous term "applicable requirements" in its denial of Sierra Club's 2016 petition to EPA to object to the Hunter Title V permit. However, on January 13, 2021, EPA denied Sierra Club's 2020 petition because EPA found that Sierra Club's claims were not raised during the public comment period for the 2020 Hunter Title V renewal permit. *Id.* at 11-14.

Despite EPA's denial of Sierra Club's petitions to EPA to object to the 2016 and 2020 Hunter Title V permits, EPA ordered UDAQ to "reopen the 2020 Permit to evaluate whether the 1997-1999 projects at the PacifiCorp-Hunter facility should have triggered PSD under the EPA-approved SIP rules applicable at that time, and, consequently, to determine whether any PSD-related 'applicable requirements' must be included in the facility title V permit." *Id.* at 16. EPA also stated that "[i]n so doing, UDAQ must consider and address the arguments presented in Sierra Club's 2015 comments…." *Id.* *See also* Sierra Club, Comments on the PacifiCorp-Hunter Power Plant DRAFT Title V Renewal Permit (Permit Number 1500101002-Draft), submitted to UDAQ on November 13, 2015 (Ex. 4). Specifically, on November 13, 2015, Sierra Club submitted comments on UDAQ's 2015 draft Title V renewal that it failed to ensure compliance with the PSD requirements of the Utah State Implementation Plan ("SIP") which became applicable to Hunter Units 1, 2, and 3 when PacifiCorp modified those units in the 1997-

1999 timeframe. November 13, 2015 Sierra Club Comment Letter to Utah Division of Air Quality on Draft Hunter Title V Renewal Permit Number 1500101002-Draft) (Ex. 3)

UDAQ responded to EPA's January 2021 reopening for cause by issuing for public comment a draft revised Hunter Title V permit on May 12, 2021. Draft Hunter Power Plant Title V Permit, Permit No. 1500101004-DRAFT, Ex. 6. The "Appendix" to that draft permit revision included UDAQ's draft response to EPA's January 2021 order reopening the Hunter Title V permit for cause, and UDAQ also included 33 attachments for which it includes links to files on a Dropbox location. *Id.* at Appendix (pdf pages 65 to 90), Ex. 6. On June 11, 2021, Sierra Club submitted comments and five exhibits on UDAQ's draft revised Hunter Title V permit responding to EPA's January 2021 order to reopen the permit for cause. Sierra Club, Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) with Utah's Response to EPA's January 13, 2021 Reopening for Cause and Exhibits A through E, submitted to UDAQ June 11, 2021 (Ex. 2). The public comment period on the Draft Hunter permit ended on June 11, 2021, UDAQ, Response to Sierra Club's Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) with Utah's Response to EPA's January 13, 2021 Reopening for Cause (dated June 11, 2021), at 1 (Ex. 7). Thus, Sierra Club's comments were timely filed. In October of 2021, UDAQ transmitted the proposed permit and its response to comments to EPA for its 45-day review, and EPA's 45-day review period that ran from October 2 to November 15, 2021. EPA Region 8 – Title V Operating Permit Public Petition Deadlines, Dec. 22, 2021, at 4, posted at https://www.epa.gov/caa-permitting/title-v-operating-permit-public-petition-deadlines-region-8, Ex. 8. EPA did not object to the Hunter Title V Permit and thus a 60-day period for the public to petition EPA to object to the permit began November 16, 2021 and ends on January 14, 2022. *Id.*

II. LEGAL BACKGROUND: BECAUSE, AS SHOWN BELOW, THIS PETITION DEMONSTRATES THAT HUNTER IS SUBJECT TO PSD REQUIREMENTS, EPA MUST GRANT THIS PETITION AND OBJECT TO THE 2021 HUNTER TITLE V PERMIT.

All sources subject to Title V must have a permit to operate that "assures compliance by the source with all applicable requirements." *See* 40 C.F.R. § 70.1(b); CAA § 504(a), 42 U.S.C. § 7661c; Utah Admin. Code R307-415-6a(1). "Applicable requirements" include the obligation under the state or federal implementation plan to obtain a PSD permit, BACT emission limits, and limits necessary to ensure protection of air quality standards and increments. 40 C.F.R. § 71.2; Utah Admin. Code R307-415-3(2), definition of "Applicable requirement," subparagraphs (a) through (k); *In re Duke Energy Indiana Edwardsport Generating Station*, Permit No. T083-271 38-00003 at 2 (Dec. 13, 2011) ("Edwardsport Petition Order") ("For a major modification of a major stationary source, applicable requirements include the requirement to obtain a preconstruction permit that complies with applicable new source review requirements (*e.g.*, Prevention of Significant Deterioration, or PSD, requirements). …The PSD program analysis must address two primary and fundamental elements before the permitting authority may issue a permit: (1) an evaluation of the impact of the proposed new or modified major stationary source on ambient air quality in the area, and (2) an analysis ensuring that the proposed facility is subject to BACT for each pollutant subject to regulation under the PSD program. CAA § 165(a)(3),(4), 42 U.S.C. § 7475(a)(3), (4).")

As defined in 40 C.F.R. § 70.2, "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*, Order in Response to Petition No. V-2008-1 (EPA, Oct. 8, 2009), at 3, available at https://www.epa.gov/title-v-operating-permits/order-denying-granting-part-columbia-gerating-station-pardeeville; Utah Admin. Code R307-415-3(2), definition of "Applicable requirement," subparagraph (a). The requirements of the PSD program, contained in the Utah state implementation plan, are just such "applicable requirements." *Sierra Club v. United States Env't Prot. Agency*, 964 F.3d 882, 891 (10th Cir. 2020) ("The regulatory definition of this term ['applicable requirements'] unambiguously refers to all requirements in a state's implementation plan, such as Utah's requirement for major NSR. "). The Act and implementing regulations require that UDAQ determine the "applicable requirements" the Hunter Plant must meet at the time of Title V permit issuance, determine whether the facility will be in compliance at the time of permit issuance, and if not, include a compliance schedule that sets forth enforceable steps leading to compliance with the applicable requirements. Utah Admin. Code R307-415-1; 307-415-5c(3)(c), (4), (5) and (8); 307-415-6a(1); and 307-415-6c(1), (3), (4) and (5). *See also* Section 110(a)(2)(C) and Part C of the Clean Air Act, 42 U.S.C. §§7410(a)(2)(C) and 7470-7479.

The Clean Air Act "requires the Administrator to issue an objection if a petitioner demonstrates that a permit is not in compliance with the requirements of the Act. *In re Kinder Morgan Crude & Condensate LLC Galena Park Terminal Harris County, Texas,* Petition No. VI-2017-15 (U.S. E.P.A. Dec. 16, 2021), at 2, *citing* 42 U.S.C. § 7661d(b)(2); 40 C.F.R.

§ 70.8(c)(l). When such a demonstration has been made, as it is below, the Administrator's duty to object is nondiscretionary. *Id.,* at 3.

Hunter's Title V permit is deficient because UDAQ did not determine as part of the permit issuance the "applicable requirements" of the PSD regulations triggered by the 1997-1999 projects or whether the plant was in compliance at the time of permit issuance, and if not, the enforceable sequence of events leading to compliance. Because of the violations of PSD permitting requirements due to the projects constructed at Hunter Units 1, 2 and 3 between 1997 to 1999, the Title V permit for the Hunter Plant must include a compliance schedule to bring each of these three units into compliance with all the requirements of the PSD program.

ARGUMENT

I. BECAUSE THE HUNTER PERMIT FAILS TO INCLUDE PSD REQUIREMENTS THAT BECAME APPLICABLE WHEN PACIFICORP CONSTRUCTED MAJOR MODIFICATIONS BETWEEN 1997 AND 1999, EPA MUST OBJECT

In the 1997 to 1999 timeframe, PacifiCorp made major modifications to Hunter Units 1, 2, and 3 which triggered the requirements to obtain a PSD permit, apply BACT for NOx, SO_2, and PM, and meet all other PSD permitting requirements including protection of the national ambient air quality standards ("NAAQS"), PSD increments, and Class I area air quality related values ("AQRVs"). No such PSD permit was issued for those projects and, as a result, all three of the Hunter units have been operating in violation of BACT and other PSD requirements since approximately the 1997 to 1999 timeframe.

A. This Section Provides an Explanation of PSD Applicability Analyses Required under the PSD Regulations of the Utah SIP in Effect at the Time of the 1997-1999 Hunter Projects and the Underlying Federal PSD Regulations for Modifications to an Existing Major Source.

EPA promulgated PSD permitting regulations to meet the PSD requirements of Part C of the Clean Air Act in 1978, and EPA revised those regulations on August 7, 1980 in response to a remand in *Alabama Power Co. v. Costle*, 636 F. 2d 323 (D.C. Cir. 1979). *See* 40 C.F.R. §§ 51.24, 52.21 (1978); *see also* 45 Fed. Reg. 52676 (Aug. 7, 1980). Utah first obtained approval from EPA to implement a PSD permitting program as part of the Utah SIP on February 12, 1982. *See* 40 C.F.R. 52.2324(c)(10).[3] EPA later approved into the SIP subsequent revisions. *See* 40 C.F.R. 52.2324(c). At the time the Hunter projects were completed in 1997-1999, the PSD regulations in effect under the Utah SIP were based on the same applicability test set forth in the 1980 federal PSD regulations. For modifications to existing major sources, PSD applicability was based on an analysis of actual emissions prior to the projects to the potential to emit after the projects. *See* definitions of "major modification," "net emissions increase," and "actual emissions" in Utah Air Conservation Regulation R307-1-1 (1995)).[4]

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[3] *See also* Utah State Implementation Plan Narrative, Section VIII Prevention of Significant Deterioration, subsection A.1, available at https://www.epa.gov/sites/default/files/2018-02/documents/table_e_ut_section_viii_prevention_of_significant_deterioration.pdf.

[4] It is difficult to re-create the EPA-approved SIP at the time of the 1997 NOI for the Hunter plant, because the Utah air permitting rules have been recodified since that time and the PSD rules have been significantly revised. The EPA does not have the older versions of the SIP-approved on its SIP website. However, we know that in 1994, EPA approved the entire Utah Air Conservation Regulations as in effect January 27, 1992 (*see* 40 C.F.R. § 52.2320(c)(25)(i)(A); 59 Fed. Reg. 35036 (July 8, 1994)). Further, revisions to Utah's definitions and PSD provisions effective in 1994 were approved by EPA in 1995 (*see* 40 C.F.R. § 51.2320(c)(28)(i)(A) and (B), 60 Fed. Reg. 22277 (May 5, 1995) and 40 C.F.R. § 51.2320(c)(31)(i)(A) and (B), 60 Fed. Reg. 55792 (Nov. 3, 1995)). Sierra Club obtained a 1995 version of the Utah rules in effect on 1/1/95 from the Utah Department of Administrative Services website which is attached as Ex. 5 to this petition. We cite to this version of Utah's PSD rules as reflective of the PSD permitting requirements that were approved as part of the Utah SIP at the time of the Hunter 1997-1999 projects. This is the same version of the Utah PSD permitting rules that we have cited in comments to UDAQ on this matter regarding the Hunter Plant since 2015, and UDAQ has never claimed that the 1/1/95 version of its rules do not reflect the SIP as in effect at the time of the 1997-1999 Hunter projects.

The definition of "major modification" excludes "routine maintenance, repair, and replacement" from being considered to be a physical change or change in the method of operation. *See* definition of "major modification" in Utah Air Conservation Regulation R307-1-1 (effective 1/1/95), Ex. 5. However, this exemption is exceedingly narrow. *United States v. So. Ind. Gas & Elec. Co.*, 245 F. Supp. 2d 994, 1009 (S.D. Ind. 2003) ("Giving the routine maintenance exemption a broad reading could postpone the application of NSR to many facilities, and would flout the Congressional intent evinced by the broad definition of medication."). EPA's 1988 Clay Memo at 3 reinforces the narrow scope of the routine maintenance exception, stating: "[t]he clear intent of the PSD regulations is to construe the term "physical change" ***very broadly***, to cover ***virtually any significant alteration*** to an existing plant. This wide reach is demonstrated by the ***very narrow*** exclusion provided in the regulations." (emphasis added).

To fall within this exception, the burden is on the source to demonstrate that the project in question satisfies a rigorous four-factor test which assesses the nature and extent, purpose, frequency and cost of the work. *Wisconsin Elec. Power Co. v. Reilly*, 893 F.2d, 901, 910 (7th Cir. 1990) (quoting September 9, 1988 Memorandum from Don R. Clay, USEPA, to David A. Kee, "Applicability of Prevention of Significant Deterioration (PSD) and New Source Performance Standards (NSPS) Requirements to the WEPCO Power Company Port Washington Life Extension Project.") (1988 Clay Memo), Ex. 7; *Cinergy*, 2006 WL 372726, at *4 (S.D. Ind. Feb. 16, 2006) ("The party claiming the benefit of an exemption to compliance with a statute bears the burden of proof as to the exemption.") (citing *First City Nat'l Bank of Houston*, 386 U.S. at 366); *Ohio Edison*, 276 F. Supp. 2d at 856; *Morgan,* No. 07-C-251-S 2007 U.S. Dist. LEXIS 82760, at *34; *Nat'l Parks Conservation Ass'n*, 618 F. Supp. 2d at 824 ("Defendant TVA bears the burden of proof as to the applicability of the RMRR exception in this case."); *E. Ky. Power Coop., Inc.*, 498 F. Supp. 2d 976, 995 (E.D. Ky. 2007).

Under the applicable PSD rules in the Utah SIP at the time of the Hunter projects completed in 1997 to 1999, a "major modification" was "any physical change or change in the method of operation of a major source that would result in a significant net emissions increase of any pollutant." *See* Definition of "major modification" in Utah Air Conservation Regulation R307-1-1 (1/1/95) (Ex. 5). Whether a project results in a significant "net emissions increase" is determined by calculating the "increase in actual emissions" based on the different definitions of "actual emissions" for pre-project and post-project periods. 40 C.F.R. §§ 52.21(b)(3)(i), (b)(21) (1980); definitions of "net emissions increase" and "actual emissions" in Utah Air Conservation Regulation R307-1-1 (1995) (Ex. 5). Once the "increase in actual emissions" is calculated for a project, it is compared to the emission thresholds defined under the definition of "significant" in Utah Air Conservation Regulation R307-1-1 (1995). *See also* 40 C.F.R. § 52.21(b)(23) (1980). Those significant emission thresholds are 40 tons per year ("tpy") for NOx, 40 tpy for SO_2, and 25 tpy for PM, among other significant emission thresholds. *Id.*

For the reasons stated in this petition, UDAQ's determination of "actual emissions" before the 1997-1999 Hunter projects was unlawful.

The term "actual emissions" was defined under the Utah SIP at the time of Hunter projects as follows:

> 1. In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the source actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operations. The Executive Secretary shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the source's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

> 2. The Executive Secretary may presume that source-specific allowable emissions for the source are equivalent to the actual emissions of the source.
>
> 3. For any source which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the source on that date.

See definition of "Actual emissions" in Utah Air Conservation Regulation R307-1-1 (1/1/95) (Ex. 5).

This definition was consistent with the federal definition of "actual emissions" in the federal PSD regulations at 40 C.F.R. §52.21(b)(21) (1980). EPA requires that state's PSD regulations meet minimum stringency requirements in order to be approved by EPA as part of the SIP.[5] 40 C.F.R. 51.166(b), which prefaces the EPA definitions for state PSD permitting programs, requires that "[a]ll state plans shall use the following definitions for the purposes of this section" and states that "[d]eviations from the following wording will be approved only if the state specifically demonstrates that the submitted definition is more stringent, or at least as stringent, in all respects" as the corresponding federal definitions. Utah's definition of "actual emissions" also tracks the definition of "actual emissions" required in EPA's regulations for gaining approval of the PSD rules as part of the SIP at 40 C.F.R. 51.166(b)(21) (1987).

According to EPA's interpretation of the definition of "actual emissions" in the federal PSD permitting regulations, the actual emissions before a change and after a change at an existing emissions unit are determined as follows:

> For an existing unit, actual emissions just prior to either a physical or operational change are based on the lower of the actual or allowable emissions levels. This "old" emissions level equals the average rate (in tons per year) at which the unit actually emitted the pollutant during the 2-year period just prior to the change which resulted in the emissions increase. These emissions are calculated using the ***actual*** hours of operation, capacity, fuel combusted and other parameters which affected the unit's emissions over the 2-year averaging period. In certain limited circumstances, where sufficient representative operating data do not exist to determine historic actual emissions and the reviewing agency has reason to

[5] The requirements for state PSD programs were originally promulgated at 40 C.F.R. § 51.24 (1980), but those provisions were recodified in 1986 to 40 C.F.R. 51.166.

> believe that the source is operating at or near its allowable emissions level, the reviewing authority may presume that source-specific allowable emissions [or a fraction thereof] are equivalent to (and therefore are used in place of) actual emissions at the unit. For determining the difference in emissions from the change at the unit, emissions after the change are the potential to emit from the units.

EPA, New Source Review Workshop Manual, October 1990, at A.41. *See* http://www2.epa.gov/nsr/nsr-workshop-manual-draft-october-1990 (emphasis added); *see also* 45 Fed. Reg. 52676, 52699 and 52718 (Aug. 7, 1980). *See also New York v. EPA*, 413 F.3d 3, 15 (D.C. Cir. 2005) ("According to EPA… an increase occurs under the 1980 regulations if… a source's past annual emissions (typically measured by averaging out the two 'baseline' years prior to the change) are less than future annual emissions (measured by calculating the source's potential to emit after the change)" (parenthetical in the original); *In re Monroe Elec. Generating Plant Entergy La., Inc* ., Order at 15 n.15 (EPA Adm'r, June 11, 1999) (attached as Ex. G) ("EPA interprets [40 C.F.R. § 51.166(b)(21)(iv)] to mean that units which have undertaken a non-routine physical or operational change have not 'begun normal operations' within the meaning of the PSD regulations, since pre-change emissions may not be indicative of how the units will be operated following the non-routine change.").

Thus, PSD applicability was based on an analysis of actual emissions prior to the projects compared with a facility's potential to emit after the projects. The "actual-to-potential" PSD applicability test was upheld by the First Circuit Court of Appeals as a controlling interpretation by EPA of its own regulations, consistent with their regulatory intent, especially because future emissions are difficult to predict. *Puerto Rican Cement*, 889 F.2d at 296-99 (citing the 1980 preamble and holding that "EPA's application of its [actual-to-potential] regulation to the facts of this case complies with the expressed intent of the regulation's writers.") (quoting *Udall v. Tallman*, 380 U.S. 1, 16-17 (1965) (quoting *Bowles v. Seminole Rock & Sand Co*., 325 U.S. 410, 414 (1945)). EPA's interpretation embodies an assumption that changed equipment "may lead the firm to decide to increase *the level of production*, with the result that, despite new machinery, overall emissions will increase." *Id*. at 297 (emphasis original).

The state and EPA definition of post-project "actual emissions" contained a presumption in 40 C.F.R. 51.21(b)(21)(iv) (1980) that post-project emissions would be the plant's "potential to emit," which is calculated based on the maximum capacity to emit a pollutant under the source's physical and operational design, unless the source accepted an enforceable limit to keep the emissions lower, in which case allowable emissions could be used for post-project emissions. *See* definition of "potential to emit" in Utah Air Conservation Regulation R307-1-1 (1/1/95) (Ex. 5). *See also* 45 Fed. Reg. at 52,677 (Aug. 7, 1980). "[T]he source owner must quantify the amount of the proposed emissions increase. This amount will generally be the potential to emit of the new or modified unit." (emphasis added)). *See also Puerto Rican Cement Co. v. U.S. Envtl. Prot. Agency*, 889 F.2d 292, 297 (1st Cir. 1989) (citing 45 Fed. Reg. at 52,677 ("the expressed intent of the regulation's writers" was that the potential to emit should be used as the plant's post-project "actual" emissions)); 63 Fed. Reg. 39,857, 39,858 (July 24, 1998); 56 Fed. Reg. 27,630, 27,633 (June 14, 1991) (explaining that the use of potential emissions is appropriate as a proxy because the pollution source's future emissions are "difficult to predict"); *see also* EPA's May 23, 2000 letter to Henry Nickel regarding the Detroit Edison Company's Monroe Plant, Enclosure at 18, n. 14.40 C.F.R. 51.166(b)(4); 40 C.F.R. 52.21(b)(4); *see also* EPA's interpretation of its 1980 PSD regulations is that any modification that is not a "routine maintenance, repair and replacement" has not "beg[un] normal operations" for calculating post-project emissions and is subject to the actual-to-potential test. 45 Fed. Reg. at 52,677 (Aug. 7, 1980).

At the time of the Hunter 1997-1999 projects, Utah's rule and approved SIP had the same pertinent definitions as EPA's 1980 PSD rules. *See* definitions of "major modification," "net emissions increase," "actual emissions," potential to emit," and "allowable emissions" in Utah R307-1-1 in Utah Air Conservation Regulation R307-1 as in effect on 1/1/95 (Ex. 5); *see also* 40 C.F.R. §52.21(b)(2), (3), (4), (16), and (21) (1980).Although EPA adopted revised rules for PSD applicability at electric utility steam generating units as revisions to the federal PSD rules in 1992, Utah did not adopt those rule changes until July of 2001. 69 Fed. Reg. 516368-51370 (Aug. 19, 2004). Those regulatory changes were not submitted to EPA until November 2001, and EPA did not approve those Utah regulatory revisions and some additional 2003 permitting revisions until August 19, 2004.[6] *Id.; see also* 40 C.F.R. § 52.2320(c)(58)(i)(A); Section VIIII.A.4. of the Utah State Implementation Plan. EPA also did not mandate that states adopt the 1992 revisions applicability rules for electric utility generating units to retain approval of their PSD permitting regulations.[7] For these reasons, those 1992 EPA PSD applicability rule revisions are not applicable to the 1997-1999 Hunter projects.

B. The 1997-1999 Hunter Projects Should Have Been Considered as Major Modifications for NO_x, SO_2, and PM under the PSD Permitting Regulations of the Utah SIP in Effect at the Time of the Projects.

1. *Coal Fired Boilers, such as the Ones at the Hunter Plant, Contain a Number of Components that Turn Combusted Coal Dust into High Pressure Steam, which Turbines and Generators Convert to Electricity.*

As discussed below, the projects at issue in this petition involved changes to the plant's turbines, superheaters, safety valves, and other components. To assist in understanding the nature of these projects, it is helpful to review how a coal-fired boiler operates. The discussion

[6] *Id.; see also* 40 C.F.R. § 52.2320(c)(58)(i)(A); Section VIIII.A.4. of the Utah State Implementation Plan.
[7] *See* 69 Fed. Reg. 51,638 at 51,639 (Aug. 19, 2004).

in this subsection relies upon an expert report submitted concurrently with this petition, by Joseph Van Gieson. *See* Report of Joseph Van Gieson, "The Effect of the 1997-1999 Projects on Hunter Units 1, 2, and 3 Emissions, January 14, 2022, at 2-11 (Ex. 23).

Although this report had not been presented previously in the course of these proceedings, it was necessitated by UDAQ's inclusion of a new document-- a 1996 Notice of Intent from PacifiCorp—that was disclosed for the first time in UDAQ's response to Sierra Club's June 11, 2021 comments to the reopening of the permit. See Ex. 1 to UDAQ's Response to Sierra Club's June 11, 2021 Comments. The 1996 Notice of Intent describes the 1997-1999 Hunter projects in more detail than the August 1997 Notice of Intent and was not included in the 2021 draft Hunter Title V permit appendix responding to EPA's reopening for cause. As a result, Sierra Club had never reviewed the 1996 document, nor had a chance to comment on it, until it was made available in UDAQ's Response to Comments in October 2021. As will be shown below and in Mr. Van Gieson's report, the descriptions in this document show that physical changes made during the projects at issue occurred at both the turbine and boiler, necessitating the application of BACT to the Hunter units. 40 CFR 70.8(d) provides that any petition to EPA "shall be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided for in § 70.7(h) of this part, unless the petitioner demonstrates that it was impracticable to raise such objections within such period." In this case, it was impractical for Sierra Club to provide the arguments it is making in this petition and in the attached expert report regarding the 1996 Notice of Intent during the public comment period because it was not made available to Sierra Club or the public until after the close of the public comment period.

Turning then to the basic workings of the Hunter units, they generate electricity through a combination of components that are designed to release the chemical energy of the coal, primarily carbon, then convert it to heat energy, mechanical energy and finally electrical energy. The chemical and heat energy conversion occurs in the boiler of a power plant. The steam turbine and generator perform the mechanical and electrical conversion processes, respectively.

The boiler receives the fuel, converts the chemical energy stored in the fuel through combustion – also known as burning, or oxidation - and applies the heat energy released by the combustion to convert water into steam. The steam is then supplied to the turbine where the heat energy of the steam is converted to mechanical energy in the form of a rotating shaft. The rotating shaft is connected to, and turns the generator to produce electricity.

The following discussion addresses the major components, and many of the auxiliary equipment components, operated at power plant units, similar to those operated at the Hunter Generating Station. The discussion first addresses the flow of fuel to the boiler, the combustion of fuel in the boiler, and the transport and treatment of the resulting gases, and solid waste. Next the flow of water and steam to and through the boiler and then through the steam turbine are described. Finally, there is a brief discussion of the electric generator to complete an introduction to the major components of a typical coal-fired steam electric generating power plant unit.

Coal Handling

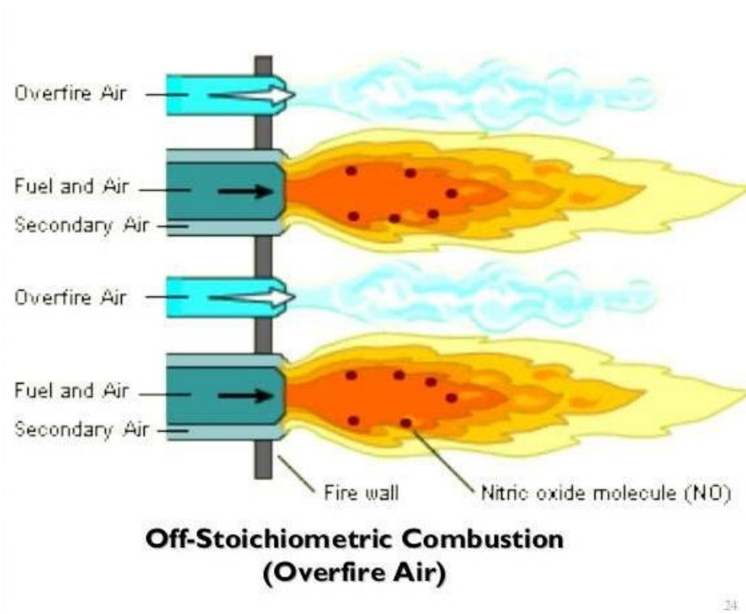
Coal comes to power plants via rail, barge, and truck. In the case of power plants located at coal mines, known as mine mouth plants, the coal moves into the plant via conveyor belts. Plant operators sample the coal as it is delivered (as received) and subsequently analyze it to determine compliance with contractual specifications for energy content, physical characteristics, and impurities. This coal analysis is called "as received" analysis. The operators then direct most of the delivered coal to the plant coal pile, where it is stored for future use. Occasionally, operators send some of delivered coal directly to the boiler. A "crusher" chops and smashes coal sent to the boiler to a one-inch diameter consistency. From the crusher, the coal goes to "bunkers" or "hoppers." Each unit has a bunker capacity sufficient to support 24-hours of operation at maximum electric generating capacity. To obtain an indication of the "as fired" coal quality entering the boiler, operators sample and analyze the coal entering the bunker or, in some cases, leaving the bunker. The coal feed rate leaving the bunkers is also measured at this point using coal scales. Coal feed rates range from 125,000 pounds per hour for smaller units to more than a million pounds per hour for large units.

At pulverized coal units, like those at Hunter, the coal drops from the bunkers to pulverizers that grind the coal to a powdery consistency similar to talcum powder. The pulverized coal is conveyed through pipes to the boiler burners by airflow provided by the primary air (PA) fans.

Coal Combustion

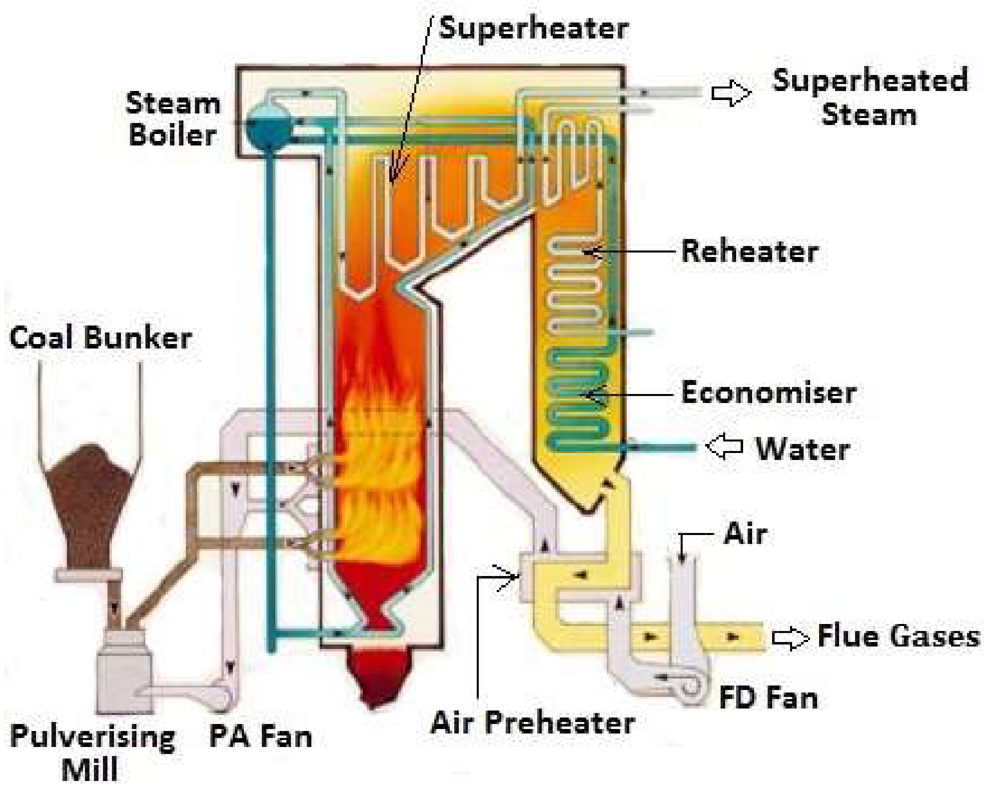
For pulverized coal units, the coal/air mixture enters the boiler through burners where it is ignited and combusts in suspension within the furnace area of the boiler. The burners are cylindrical in shape and have internal baffles that create a swirling motion of the coal/air mixture to promote thorough mixing resulting in more complete combustion. The burners are mounted on the boiler walls in burner panels with circular openings to support the burners. Pulverized coal-fired boilers can have as many as thirty or more burners. The burners at some boilers have the capability to change their vertical angle with respect to the boiler walls in order to achieve optimum distribution of the heat release from the combustion of the coal.

Secondary air enters the boiler furnace through concentric openings around the burners. The secondary air is provided by the forced draft (FD) fans to the windbox, a rectangular-shaped chamber which envelopes the burner panels that equalizes and stabilizes the secondary airflow to the burners. The flame resulting from the combustion, or oxidation, of the pulverized coal/air mixture extends into the furnace area of the boiler, releasing the chemical energy present in the coal in the form of light and heat energy. Some low NOx combustion control systems employ the addition of some of the secondary air through ports in the water walls located above the burners known as over fire air ports. An illustration of the relative burner and over fire air ports is shown below.



The reaction of the carbon and hydrogen contained in the coal with the oxygen contained in the primary and secondary combustion air releases heat and light energy. Carbon dioxide (CO_2), oxides of Nitrogen (NOx), sulfur dioxide (SO_2) and other gases are also produced as byproducts of combustion. These gases are referred to as flue gas. Another byproduct of combustion is ash. Ash is contained in the coal fed to the boiler. It is relatively inert and either falls to the bottom of the boiler and exits as bottom ash or is entrained with the flue gas and exits the boiler as flyash. Some flyash adheres to boiler tube surfaces and is called slag. Flyash also can collect on the surface of the air preheater and will be discussed again later.

Much of the heat energy released from the coal is contained in the flue gas and as much of that energy as possible will be recovered by the boiler, and the air preheater which is located downstream of the boiler. Here is diagram of the flow of air combustion gases through a boiler.



Pulverized Coal-Fired Boiler

The water and steam that flows through the tubes of the boiler components also control tube temperature by removing heat and carrying it from the tubes. If this heat transfer did not occur, the tubes would be destroyed almost immediately. Long-term exposure of the tubes to the temperatures in the boiler lead to tube cracks and leaks, even when effective cooling by steam and water occurs. Boiler tubes are periodically sampled and evaluated using metallurgical analysis techniques to determine their status regarding long-term degradation.

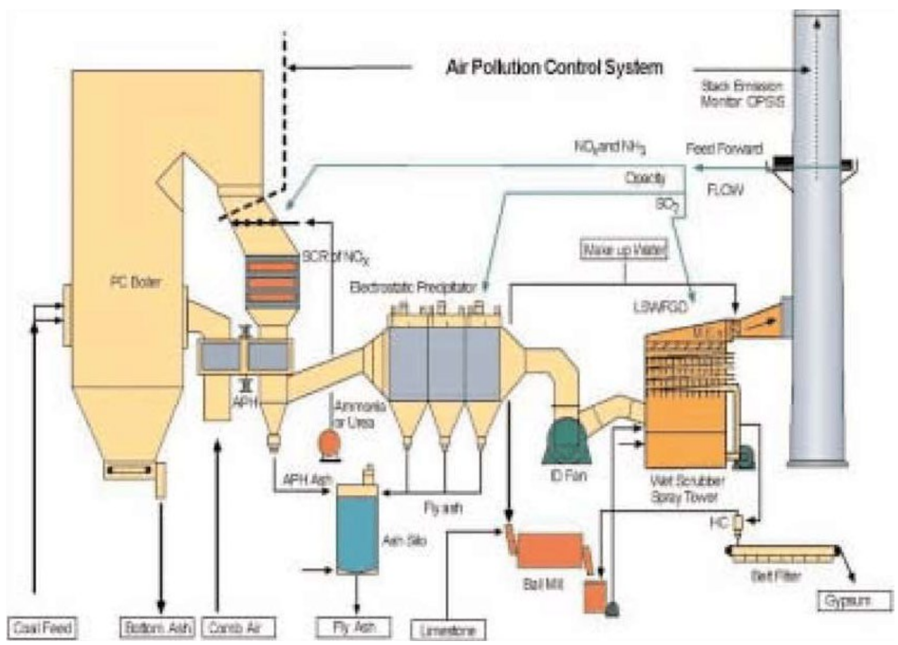
Boilers are composed of two major sections – the radiant section, and the convection section. The radiant section includes the furnace, where combustion occurs, and the upper sections of the boiler exposed to the radiant energy. The wall tubes, also called water wall tubes, furnace wall tubes, or risers primarily absorb radiant energy. The secondary superheaters, and secondary reheaters (when they are employed) are located in the upper region of the radiant section of the boiler and primarily absorb radiant energy. The convection section of the boiler is designed to recover the heat energy of the gases, through a heat transfer process called convection. Convection is the transfer of heat between a liquid or gas and a solid material. In the case of boiler convection sections, the tubes of the primary superheater, primary reheater, and economizer absorb the heat contained in the flue gas and transfer the heat to the water or steam passing within the tubes. Superheaters, reheaters, and economizers will be described further in the water and steam system discussion that follows.

After the flue gases pass through the economizer, they still contain a significant amount of heat. The gases at this point can have temperatures as high as 800 degrees Fahrenheit (°F). Air heaters, also known as air preheaters are heat exchangers that recover heat from the exiting flue gas and transfer to heat energy to the incoming combustion air leaving the forced draft fans and raising the air temperature, prior to entering the pulverizers and boiler. Increasing the temperature of the combustion air improves boiler and unit efficiency.

The economizers and air pre-heaters at many coal fired power plants experience deposits of flyash which present a restriction to the flow of flue gas exiting the boiler. The flow restriction can exceed the capability of the induced draft fans to draw the flue gas from the boiler at a sufficient flow rate to support combustion at full load conditions.

After the flue gas leaves the air pre-heater, it is treated for air pollutant removal and is drawn from the boiler by induced draft fans which direct the gas to the stack for release into the atmosphere. A photograph of an induced draft fan at an electric utility boiler is seen below. Induced draft fans provide the force that draws the flue gases from the boilers, through the air pollution control equipment and stack before release to the atmosphere. Electric utility boilers rely on the induced draft fans to sustain sufficient flue gas flow rate to keep boiler furnace gas pressures to allow combustion rates that support the required steam flow to the turbines.

Hunter Units 1, 2 and 3 employ flue gas desulfurization scrubbers (FGD) for control of SO_2 emissions, and electrostatic precipitators (at Units 1&2) and a baghouse (at Unit 3) for control of particulate matter emissions. Low NO_x burners with overfire air are operated for the control of nitrogen oxides emissions. The mass flow rate of air pollution emissions leaving the boiler, in units of pounds per hour (lb/hr), is directly related to the amount of coal entering the boiler which is directly related to the amount of heat required to produce the flow of steam required to fulfill the electricity demand on an electric generating unit. The following diagrams illustrate the relative locations of the boiler an air pollution control equipment at a typical coal fired electric utility unit.

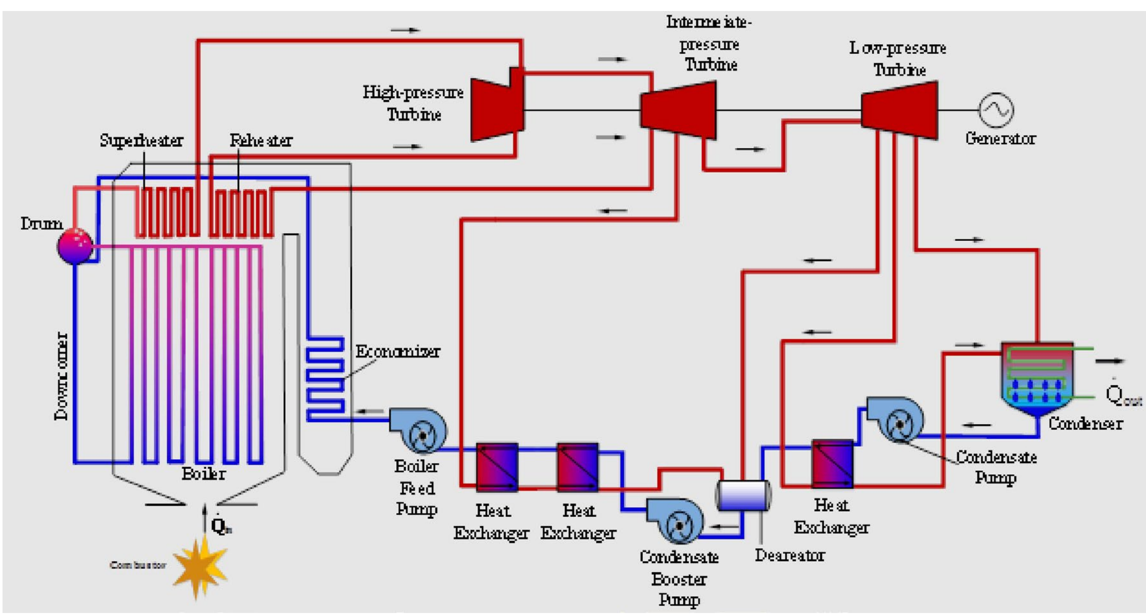


Boiler Water/Steam Cycles

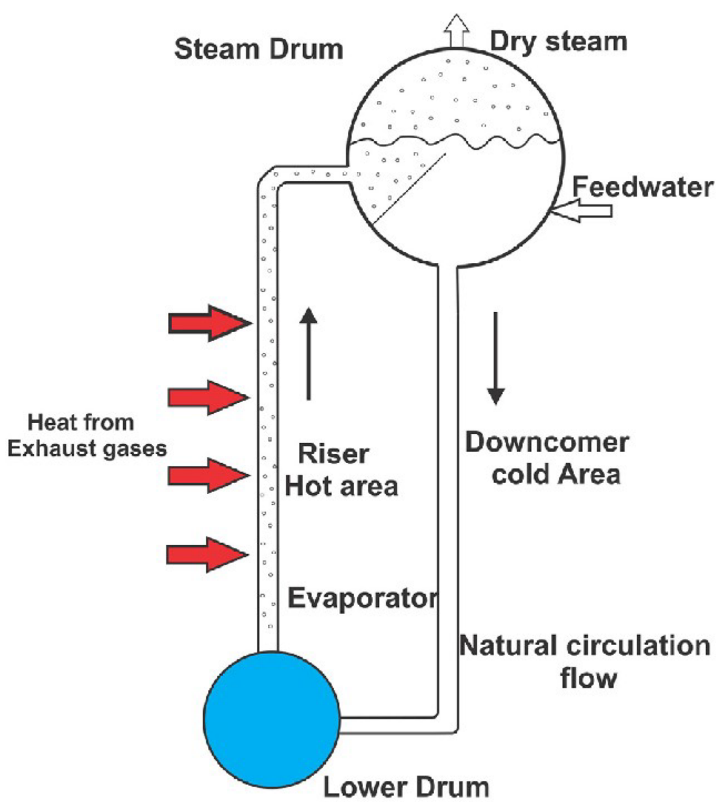
The boiler combustion process is a once-through process, with air and fuel entering the boiler, and flue gases leaving. The water/steam cycle is a closed-loop process that involves not only the boiler but also several other components including the turbine, condenser condensate pumps, feedwater heaters and boiler feed pumps. Each of these components will be described below with emphasis on the boiler and turbine.

Feedwater enters the boiler from boiler feed pumps, absorbs the heat released from coal combustion, changes to steam, and leaves the boiler. The steam is then supplied to the turbine, where it releases most of the heat energy transferred from the boiler and is condensed back to water in the condenser upon leaving the turbine. The condensate is pumped via condensate pumps through feedwater heaters and then by boiler feed pumps, back to the boiler. Each of the main components of the cycle, the boiler, turbine, condenser, feedwater heaters and boiler feed pumps are discussed below, with emphasis on the boiler water; and steam components. A more detailed discussion of the water and steam process components follows. The diagram below provides a more detailed view of a typical power plant water and steam cycle.

Feedwater is pumped by the boiler feed pump to the economizer. The economizer is the last component that receives energy from the combustion gas. It is located in the lowest portion of the convection section of the boiler. The combustion gas in the economizer is at the lowest temperature (700-800 ° F) prior to leaving boiler.



Feedwater exits the economizer and enters the main steam drum which is located near the top of the boiler. The main steam drum receives the feedwater and discharges it to the bottom of the boiler furnace through large pipes called downcomers, also known as supply tubes, located outside of the boilers. The downcomers transport the feedwater to the lower waterwall headers that distribute it to the furnace wall tubes, also called waterwall tubes or risers. The water in the waterwall tubes absorb the energy released by combustion and is converted to steam as it rises in the tubes and is returned to the steam drum. The feedwater heating and conversion to steam absorbs approximately 60% of the total energy absorbed by entire boiler. A simple diagram illustrating the circuit of the feedwater leaving the drum and returning as steam is shown below.



The steam drum contains feedwater received by the boiler feed pump, and steam produced by water walls. The steam and water are segregated within the drum. The steam entering the drum passes through steam-water separators that remove any remaining water from the steam, and return the water to the downcomers.

The steam in the main steam drum is in a thermodynamic condition known as saturation. Saturated steam has received, and contains just enough energy to exist as steam and would return to liquid if the temperature were lowered only slightly. Addition of energy to saturated steam produces super-saturated steam at an energy state above the saturated state. Super-saturated team has the ability to accept additional energy and electric utility boilers exploit this characteristic to utilize the energy storage capacity of steam to absorb more heat in a boiler tube component call the superheater.

The water and steam are separated inside the steam drum using centrifugal water separators. The steam the flows to the superheater which absorbs and transfers additional heat to the steam, raising the energy state to super-saturation. Superheaters are often comprised of two sections. The primary superheater is located at the top of the furnace convection section, upstream of the economizer. Primary superheater construction appears similar to economizer shape, and orientation, but the tube material is selected to withstand the higher gas and steam temperatures than those experienced in economizers. The steam first enters the primary superheater inlet header. The inlet header is large cylindrical tube or pipe usually one to two feet in diameter. The header is connected to the inlet of each primary superheater tube element, and is therefore as long as the primary superheater is wide. The steam flows through the tube elements, reversing direction several times as the tubes turn 180° back and forth across the gas flow, and exit the tube elements to the outlet header. The outlet header is similar in design to the inlet header, and collects the steam for transfer to the secondary superheater.

Secondary superheaters are sometimes comprised of multiple sub-components, also known as the pendant superheater, second superheater, intermediate superheater, finishing superheater, high temperature superheater, and the outlet superheater among other terms that are often unique to individual boiler manufacturers.

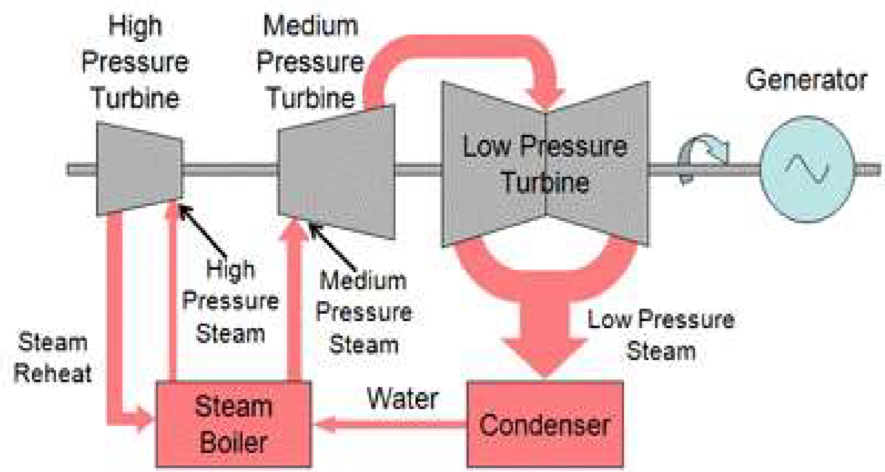
Secondary superheaters are located in the upper region of the radiant section of the boiler, where the gas temperature is higher than at the primary superheater location, and radiant energy is also available for absorption. The secondary superheater tube elements hang vertically from the boiler roof, suspended from the secondary superheater inlet header, shown in the upper left portion of the diagram above. Secondary superheater tube elements are referred to as pendants, or platens. Secondary superheaters comprise from a few dozen to as many as 200 tube elements, or pendants that can reach 50 feet in length. The steam leaving a secondary superheater usually has a temperature of approximately 1, 000 ° F, pressures ranging from 2,400 to 3,100 pounds per square inch, and is at the highest energy level of the steam cycle. After leaving the superheater the steam enters the high pressure turbine.

The superheated steam leaving the superheater is transferred through the superheater outlet header to the steam turbine, which usually has three components, a high-pressure (HP) turbine, an intermediate-pressure (IP) turbine and a low-pressure (LP) turbine. The steam enters the high pressure turbine and upon leaving the turbine is returned to the boiler. In the high pressure turbine, much of the steam energy is converted to mechanical, kinetic energy in the form of the rotating turbine shaft. This conversion of energy causes steam temperature and pressure to lower as the steam passes through the high pressure turbine. If the steam temperature is lowered too much, some of the steam may return to liquid state, or to water if more energy is lost. Water droplets damage internal turbine components, and the energy transfer efficiency of the turbine is reduced when water is present. Steam exits the high pressure turbine and enters the primary reheater in the boiler via steam pipes before water forms in the turbine.

Reheaters are used to recover additional heat energy from the flue gas, and increase the energy state of the steam to reduce water formation in the turbine and to increase the amount of energy in the steam available for conversion in the turbines. In some boilers, only one reheater component is employed. Other boiler designs include a primary and a secondary superheater section. After leaving the reheater, the steam enters the intermediate-turbine and then the low pressure turbine before entering the condenser.

Steam Turbines, Condensers and Feedwater Heaters

Steam turbines transform the energy of the high temperature, high pressure steam delivered from the boiler into mechanical energy in the form of the rotating turbine shaft. The conversion the steam energy to mechanical energy is accomplished as the steam expands through a stationary nozzle (or stage, or diaphragm), and impacts and reacts with a rotating blade (or bucket) attached to the turbine shaft. The nozzles and blades are arranged axially around the axis of the horizontal turbine shaft. The nozzle ring is stationary, connected to the turbine housing, or shell. The blade wheel is directly connected to the turbine shaft. The nozzle turns the axial steam flow into a rotational flow prior to impaction on the blade wheel, which is connected to the turbine shaft. A diagram of a steam turbine system is shown below.



Multi Stage Steam Turbine Generator

Steam leaving the boiler superheater enters the high pressure steam turbine, and returns to the boiler reheater. After leaving the reheater, steam returns to the intermediate, or medium pressure, turbine. Steam exiting the intermediate pressure turbine enters and passes through the low pressure turbine and exits to the condenser where the steam is condensed to water. This water pumped by the condensate pump through a series of feedwater heaters that use steam extracted from the turbine to increase the feedwater temperature and then is returned to the boiler at the economizer by the boiler feed pumps.

Electric Generators

An electric generator is essentially two magnets. One is called the stator, which is a stationary electromagnet with conducting wire windings around its periphery. The rotor, is a magnet that is attached to the turbine shaft with windings attached to a source of direct current called and exciter. The magnetic field of the spinning rotor produces sweeps the inner surface of the stator producing an electric voltage in the stator windings. The generator output is connected to the consumers through the main transformers. The generator of a large steam-electric plant can produce enough electricity to supply 3,500,000 residential customers.

2. *The 1997-1999 Hunter Projects Made Physical Changes at Units 1, 2, and 3 That Should Have Been Projected to Result In Significant Net Emission Increases of NOx, SO_2, and PM.*

In a 1997 permit application (called a "Notice of Intent"), PacifiCorp notified UDAQ of several projects that it was undertaking at Hunter Units 1, 2, and 3. PacifiCorp, Notice of Intent, Request for Approval Order Modifications to Limit the Potential to Emit at the Hunter Plant, submitted to UDAQ on August 18, 1997. (Ex. 9). Several projects were identified to be constructed at the Hunter units, as shown in the table below. The projects listed in italics occurred at the turbine; the rest at the boiler:

Table 1. PacifiCorp's List of Projects at the Hunter Plant, From Table 1 of PacifiCorp's August 18, 1997 Notice of Intent (Ex. 9).

Hunter Unit	Project	Estimated Date of Completion
3	Rotating classifiers on mills	8/96
	Addition of riser and supply tubes	6/98
	Replacement of superheater outlet bank and manifolds	6/98
	Overfire air ports for added NOx control	6/98
	Replacement of oil ignitors	5/96
	Resizing of cold reheat safety valves	6/98
	Turbine changes including aeroderivative design	6/98
	Installation of on-line performance manager	10/95
	Installation of condensate polisher	8/97
1	Replacement of air heater elements	11/99
	Rotating classifiers on mills	Listed as "under evaluation"[a]
	Addition of superheater surface area	Listed as "under evaluation"[a]
	NOx control project including burner and/or windbox changes	11/99
	Turbine changes including ruggedized rotor design	11/99
2	Replacement of air heater elements	11/97
	Rotating classifiers on mills	Listed as "under evaluation"[a]
	Addition of superheater surface area	Listed as "under evaluation"[a]
	NOx control project including burner and/or windbox changes	11/97
	Turbine changes including ruggedized rotor design	11/97

[a] UDAQ states that the projects listed as "under evaluation" in PacifiCorp's August 18, 1997 Notice of Intent were not completed. *See* 2021 Hunter Title V Permit, Appendix at 5 (Ex. 1).

In the 1997 permit application, PacifiCorp acknowledged that these combined projects would lead to an emissions increase. PacifiCorp stated that "[a]fter further evaluation of the combined projects, PacifiCorp believes that it must accept voluntary emission limits that are federally enforceable to limit the post-change potential to emit from the facility." *Id.*, cover letter at 1. That PacifiCorp, with this statement, essentially admitted that without an emission limitation, the projects would trigger PSD requirements, is powerful evidence in support of this petition. PacifiCorp further stated: "Many of the projects, in and of themselves, could not cause an increase in emissions. However, as a whole, the upgrades may increase the actual capacity and capacity utilization of the boilers." *Id.* PacifiCorp also stated: "PacifiCorp believes that an increase in capacity utilization following the completion of the projects has the potential to cause an increase in annual emissions above that which could have been accommodated prior to the changes." *Id.* at pdf page 9 (Table entitled "Hunter Plant and Coal Prep Plant Annual Emissions Inventory, Production Data Input Sheet for Calendar Year: EPA Baseline Emissions") and pdf page 12 (Table entitled "Hunter Plant and Coal Prep Plant Annual Emissions Inventory, Production Data Input Sheet for Calendar Year: Future Potential Emissions").

These acknowledgments that the projects would increase emissions are confirmed by data provided in the August 18, 1997 Notice of Intent, where PacifiCorp indicated that the hourly heat input capacity, measured in million British Thermal Units of heat input per hour ("MMBtu/hr"), would be increasing with these modifications. This is shown in Table 2 below.

Table 2. Increase in Heat Input Capacity at Hunter Unit 1, 2 and 3 Identified in PacifiCorp's August 18, 1997 Notice of Intent[8]

Hunter Unit	Baseline Hourly Heat Input	Source of Information	Maximum Projected Heat Input	Source of Information
1	4,160 MMBtu/hr	EPA Review – Emissions calculations	4,700 MMBtu/hr	Production data and heat and material balance
2	4,160 MMBtu/hr	EPA Review – Emissions calculations	4,700 MMBtu/hr	Production data and heat and material balance
3	4,160 MMBtu/hr	EPA Review – Emissions calculations	4,900 MMBtu/hr	Heat and material balance

Because the project at issue were going to inevitably lead to emissions increases, in the August 18, 1997 Notice of Intent, PacifiCorp requested limits on potential to emit of all three units to show that post-project emissions would not exceed the PSD "baseline emission inventory." *See* August 18, 1997 Request for Approval Order Modifications to Limit the Potential to Emit at the Hunter Plant, at 1 (Ex. 9). According to PacifiCorp, "the PSD baseline inventory was established at the time the Hunter Plant received a permit for Hunter units 3 and 4." *Id.* Table 3 below identifies the new limits that PacifiCorp requested to be imposed on the Hunter units. Notably, PacifiCorp stated "[r]educed short-term limits for the Unit 3 boiler are requested, because ***the physical changes to this boiler have the potential to increase short term emission rates***." *Id.* at 2, emphasis added.

8 *Id.* at pdf pages 9 and 12 (from Table with Heading "Hunter Plant and Coal Prep Plant Annual Emissions Inventory Production Data Input Sheet for Calendar Year: EPA Baseline Emissions" and from Table with Heading: "Hunter Plant and Coal Prep Plant Annual Emissions Inventory Production Data Input Sheet for Calendar Year: Future Potential Emissions").

Table 3. PacifiCorp's Proposed New Emission Limits for Hunter Units 1, 2 and 3 Requested in its August 18, 1997 Notice of Intent (Ex. 9)[9]

Hunter Units	Pollutant	Existing Limit (According to PacifiCorp)	Proposed Limit
1&2	Particulate matter	0.10 lb/MMBtu (6-hour averaging period)	0.05 lb/MMBtu (6-hour average) Proposed in addition to existing limit
	SO_2	1.2 lb/MMBtu (3-hour averaging period)	0.21 lb/MMBtu (12-month average) Proposed in addition to existing limit
	NOx	0.70 lb/MMBtu (3-hour averaging period)	0.45 lb/MMBtu (12-month average) Proposed in addition to existing limit
Unit 3	Particulate Matter	0.03 lb/MMBtu (6-hour averaging period)	0.02 lb/MMBtu (6-hour average) Proposed to replace existing limit
	SO_2	0.12 lb/MMBtu (30-day rolling averaging)	0.10 lb/MMBtu (30-day rolling average) Proposed to replace existing limit
	NOx	0.55 lb/MMBtu (30-day rolling average)	0.46 lb/MMBtu (30-day rolling average) Proposed to replace existing limit

PacifiCorp stated that the intent of these new lower limits was to limit the potential to emit of post-change emissions at the Hunter plant so that there would be no significant increase in emissions from the 1997-1999 projects. *Id.*, cover letter at 2 and Attachment at Table 5. As will be shown below, however, these requested limits were insufficient to prevent PSD applicability.

On November 20, 1997, UDAQ issued an Approval Order for the Hunter Plant. *See* November 20, 1997 Approval Order DAQE-1099-97 (Ex. 10). On December 18, 1997, UDAQ issued a second Approval Order for the Hunter Plant. *See* December 18, 1997 Approval Order DAQE-1189-97 (Ex. 11).[10] UDAQ's New/Modified Source Plan Review attached to the

[9] *Id.,* Attachment, at Table 4.

[10] According to a May 3, 2005 letter that is attached to the November 20, 1997 Approval Order, the state administratively revoked the November 20, 1997 Approval Order on May 3, 2005 (see Ex. 10). It appears the primary difference between the December and November Approval Orders is that the December 1997 Approval Order removed a limit on the sulfur content of any coal burned to not exceed 1.0 pounds of sulfur per million BTU heat input that had been in Condition 6 of the November 20, 1997 Approval Order. See November 20, 1997 Approval Order DAQE-1099-97 at 4 (Ex. 10) and compare to December 18, 1997 Approval Order DAQE-1189-97 at 3 (Ex. 11).

December 1997 Approval Order states that it was based on PacifiCorp's Notice of Intent dated August 20, 1997. UDAQ, New/Modified Source Plan Review, Hunter Plant Emission Factors – Consolidation AP, September 30, 1997, at 1 (Ex. 11 at pdf page 9). Furthermore, UDAQ's New/Modified Source Plan Review states the following regarding the permit action:

> PacifiCorp Electric Operations, as part of the consolidation measures for a Title V operating permit, has submitted a [Notice of Intent] for the consolidation of all three Hunter power plant units located near Castle Dale, Utah…PacifiCorp is requesting that additional enforceable emission limits be established which will limit the potential to emit (PTE) from this source. **These limits are being imposed to demonstrate that the consolidation will not exceed the Prevention of Significant Deterioration (PSD) baseline emission inventory. A number of projects, which may increase the capacity or capacity utilization of the three units, have been planned or completed. The net effect of these projects could be an increase in emissions, hence the newly requested limits to insure an emission decrease.**

Id. at 3 (Ex. 11 at pdf page 11) (emphasis added). UDAQ's New/Modified Source Plan Review also states that "[t]he Hunter plant is decreasing their emissions significantly. Therefore, this Notice of Intent is not a major modification." *Id.* at 13 (Ex. 11 at pdf page 21). As shown below, this statement was erroneous.

Condition 5 of the 1997 Approval Orders included new limitations on particulate matter, SO_2, and NOx that were identical to those requested by PacifiCorp in its August 18, 1997 Notice of Intent as presented in Table 3 above. S*ee* November 20, 1997 Approval Order DAQE-1099-97, at 3-4 (Condition 5) (Ex. 10). *See also* December 18, 1997 Approval Order DAQE-1189-97 at 4-5 (Condition 5) (Ex. 11).

The November 1997 and December 1997 Approval Orders indicated that the "total emissions from the consolidated source (all three Hunter units) will decrease as follows: PM10: -112, NOx -8551, SO_2 -679, CO -1063, VOC – 632 (all numbers are in tons per year)."[11]

[11] S*ee* November 20, 1997 Approval Order DAQE-1099-97, at 2 (Ex. 10). *See also* December 18, 1997 Approval Order DAQE-1189-97 at 2 (Ex. 11).

However, this permit did not result in any reduction of actual emissions and, in fact, actual emissions increased significantly after the projects, as will be discussed further below.

Moreover, there was an overarching flaw in the methodology relied on by UDAQ to establish that there would be no significant net increase in emissions as a result of these projects at the Hunter units. Specifically, the post-change potential to emit was compared to an "allowable emissions" baseline rather than an actual emissions baseline. UDAQ misapplied the relevant law and regulations and has not justified its approach as lawful or technically valid in its response to EPA's reopening of the Hunter Title V permit for cause.

To determine properly PSD applicability for the 1997-1999 Hunter projects, the law first requires a determination of the baseline by calculating the two year-average actual emissions of each Hunter unit for the two years immediately prior to submittal of PacifiCorp's Notice of Intent in 1997. The baseline calculation below relies upon PacifiCorp's Hunter Emissions Inventory reports for 1995 and 1996 (the two years prior to the 1997-1999 Hunter projects) that UDAQ included in the Appendix to the 2021 Hunter Title V permit that responds to EPA's reopening for cause. Hunter Emissions Inventory 1995 (Ex. 14) and Hunter Emissions Inventory 1996 (Ex. 15), which are Attachments 5 and 6 to the 2021 Hunter Title V Permit Appendix. PacifiCorp's emission summary calculations were based on each unit's annual consumption of coal, the weighted annal average heating value and ash content of the coal, and NOx and SO_2 annual average emission rates from continuous emissions monitoring systems (CEMs) data for the year. Hunter Emissions Inventory 1995 at p. 2 (Ex. 14) and Hunter Emissions Inventory 1996 at p. 2 (Ex. 15).

Next, a PSD applicability determination for a modification must compare baseline emissions with post-project potential to emit. The calculation below is based on PacifiCorp's stated hourly heat input after the projects (shown in Table 2 above) and its requested emission limits for NOx, SO_2, and PM (shown in Table 3 above), which were provided in its August 1997 Notice of Intent. *See* August 18, 1997 Request for Approval Order Modifications to Limit the Potential to Emit at the Hunter Plant, at pdf page 12 (table for Future Potential Emissions) and at pdf page 6 (Table 4) (Ex. 9). UDAQ imposed the requested emission limits in terms of pounds of pollutant per million British Thermal Unit heat input ("lb/MMBtu") in the 1997 Approval Orders issued for the projects. *See* November 20, 1997 Approval Order DAQE-1099-97 at 3-4, Condition 5 (Ex. 10); and December 18, 1997 Approval Order DAQE-1189-97 at 2-3, Condition 5 (Ex. 11). Because PacifiCorp did not request a limit on operating hours or production rate in its August 197 Notice of Intent, and UDAQ never imposed such limits in the 1997 Approval Orders for the Hunter units, post-change potential to emit must be calculated assuming the units operate continually throughout the year (i.e., 8,760 hours per year), as is commonly assumed by EPA. *See*, e.g., May 16, 1979 Letter from Edward E. Reich, EPA, to Jerry L. Phillips, Burns & McDonnell, available at https://www.epa.gov/sites/default/files/2015-07/documents/respletr.pdf.

Table 4 below shows that, based on a comparison of actual emissions before the 1997-1999 projects to potential to emit after the 1997-1999 projects, the Hunter projects permitted by UDAQ in 1997 should have been projected to result in significant emission increases of NOx, SO_2, and PM under the PSD regulations of the Utah SIP as in effect at the time.

Table 4. Determination of Whether the Hunter Projects Detailed in PacifiCorp's August 1997 NOI Should Have Been Projected to Result in a Significant Emission Increase Using an Actual Emissions Baseline for All Units and Pollutants[12]

Pre-Project Actual NOx (95-96 Avg), tpy	Post-Project PTE NOx, tpy	Increase in NOx, tpy	Pre-Project Actual SO_2 (95-96 Avg), tpy	Post-Project PTE SO_2, tpy	Increase in SO_2, tpy	Pre-Project Actual PM (95-96 Avg), tpy	Post-Project PTE PM, tpy	Increase in PM, tpy
Hunter Unit 1								
6,993	9,264	**2,271**	2,534	4,323	**1,789**	651	1,029	**378**
Hunter Unit 2								
6,672	9,264	**2,592**	2,404	4,323	**1,919**	597	1,029	**433**
Hunter Unit 3								
6,273	9,873	**3,600**	1,206	2,146	**940**	257	429	**173**
Hunter Plant								
19,937	28,400	**8,463**	6,144	10,792	**4,648**	1,505	2,488	**983**

Under the PSD regulations of the Utah SIP in effect at the time of the 1997-1999 Hunter projects, a "significant" emission increase is defined as an emissions increase that equals or exceeds 40 tons per year for NOx, 40 tons per year for SO_2, and 25 tons per year for PM. *See* definition of "significant" in Utah Air Conservation Regulations R307-1-1 as in effect on 1/1/95 (Ex. 5). As demonstrated in Table 4 above, based on data submitted by PacifiCorp in its 1997 Notice of Intent and in its 1995 and 1996 Annual Emission Inventories submitted to UDAQ, the 1997-1999 Hunter projects should have been projected to result in significant emission increases of NOx, SO_2, and PM at each Hunter unit and at the Hunter plant as a whole.

EPA has always had a two-step process for determining whether a major modification has occurred: First, determine whether the *increase* in emissions from a proposed physical

[12] This table is a reprint of Table 7 from Sierra Club's June 11, 2021 Comment Letter to UDAQ on the draft 2021 Hunter Title V Permit reopening. *See* Sierra Club, Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT), submitted to UDAQ June 11, 2021 at 25 (Ex. 2).

change/change in the method of operation would be significant and, if so, determine whether a significant *net* emissions increase will occur.[13] An evaluation of "net emissions increase" takes into account all creditable and contemporaneous emission increases and emission decreases. Pursuant to the definition of "net emissions increase" in the Utah SIP (as well as in federal PSD regulations), an emissions increase or decrease is considered contemporaneous with a project if its occurs "between the date five years before construction on the particular change commences; and the date that the increase from the particular change occurs." *See* definition of "net emissions increase" in Utah Air Conservation Regulations R307-1-1 as in effect on 1/1/95 (Ex. 5). *See also* 40 C.F.R. 51.166(b)(3)(ii); 40 C.F.R. 52.21(b)(3)(ii). Further, the definition of "net emissions increase" as in effect at the time of the 1997-1999 Hunter projects had limitations on the emissions increases and (most relevant here) the emission decreases could be considered creditable for calculating the net emissions increase. Specifically, Utah's definition of "net emissions increase" in effect at the time of the 1997 -1999 Hunter projects provided in Section 2.E. that:

> A decrease in actual emissions is creditable only to the extent that:
>
> (1) The old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions;
>
> (2) It is enforceable at and after the time that actual construction on the particular change begins; and
>
> (3) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change.

[13] As discussed in 67 Fed. Reg. 80,186 at 80190 (December 31, 2002). *See also* January 22, 1981 EPA Memorandum entitled "PSD Applicability" in which EPA stated that "EPA is interpreting the term 'net emissions increase' as any significant increase in actual emissions from a physical change or change in the method of operation and any other creditable contemporaneous increases or decreases in actual emissions," available at https://www.epa.gov/sites/production/files/2015-07/documents/crgilinc.pdf.

(4) It has not been relied on in issuing any permit under Section R307-1-3.1 nor has it been relied on in demonstrating attainment or reasonable further progress.[14]

Although PacifiCorp requested reduced emission limits in its August 1997 Notice of Intent to reduce its potential to emit, those reduced emission limits would not result in emissions lower than then the pre-project 1995-1996 average annual "actual emissions" as demonstrated in Table 4 above. Thus, the reduced emission limits of the 1997 Approval Order failed to adequately create creditable emission reductions that could be used to "net out of PSD" the projected emission increases show in Table 4 above.

There were creditable and contemporaneous emission increases in PM emissions that needed to be taken into account in the evaluation of net emissions increase. The primary contemporaneous emission increases were those associated with the increased coal use at the Hunter units. Specifically, in its August 1997 Notice of Intent, PacifiCorp provided "EPA Baseline Emissions" and "Future Potential Emissions" for several emission points associated with coal transfer and ash transfer that projected an increase in emissions from these emission points due to an increase in coal usage and an increase in ash production. Those increase in PM emissions are shown in Table 5 below.

[14] *Id.* at Section 2.E.

Table 5. Other Emission Points Identified by PacifiCorp in the August 18, 1997 NOI as Increasing Emissions with the Hunter Projects[15]

Unit ID#	Description	Baseline PM, tpy	Future Potential PM, tpy	PM Emission Increase, tpy	Baseline PM10, tpy	Future Potential PM10, tpy	PM10 Emission Increase, tpy
304	Loading ash into haul trucks (U1&U2)	0.0114	0.0187	0.0073	0.0040	0.0066	0.0026
305	Loading ash into haul trucks (U3)	0.0057	0.0098	0.0041	0.0020	0.0034	0.0014
401	Coal transfer to coal pile at power plant	0.31	0.34	0.03	0.11	0.12	0.01
501-503	Fly ash unloading at landfill	0.07	0.11	0.04	0.02	0.04	0.02
601-637	Ash haul road	30.62	48.36	17.72	11.02	17.41	6.39
701	Baghouse No. 1 (3DC1-screen building)a	Not Included	8.70	8.70	Not Included	8.70	8.07
702	Baghouse No. 2 (5DC1-transfer building)a	Not Included	2.77	2.77	Not Included	2.77	2.77
801	Coal transfer from truck	0.31	0.36	0.05	0.11	0.13	0.02
1001-1008	Coal haul road (paved)	8.36	9.66	1.3	1.63	1.89	0.26
1009-1014	Coal haul road (paved)	80.36	92.89	12.53	15.68	18.13	2.45
1101-1102	Coal haul road (loaded truck, unpaved)	7.90	9.13	1.23	2.84	3.29	0.45
1201-1205	Coal haul road (Empty truck, unpaved)	4.50	5.21	0.71	1.62	1.87	0.25
1301-1309	Refuse haul road (unpaved)[a]	Not included	Not included	1.50	Not included	0.54	0.54
Total PM Increases				46.6 tpy	Total PM10 Increases		21.2 tpy

[a] Note that it appears these emission points should have been included in the baseline emissions and not as contemporaneous emission increases, because the August 18, 1997 NOI identifies these sources as permitted in a May 15, 1990 Approval Order.

[15] *See* PacifiCorp's August 1997 Notice of Intent at pdf pages 25-68 (Ex. 9). Note that this table is a reprint of Table 14 from Sierra Club's June 11, 2021 Comment Letter on the 2021 Hunter Title V Permit Reopening at 33-34 (Ex. 2).

Table 6 below provides the net emissions increase that should have been projected for the 1997-1999 Hunter projects, including the contemporaneous emission increases shown in Table 5 above, but not including the emission decreases because there were no creditable emission decreases.

Table 6. Net Emissions Increase that Should Have been Projected for the 1997-1999 Hunter Projects Using an Actual Emissions Baseline for All Units and Pollutants[16]

Baseline Actual NOx (95-96 Avg), tpy	**Post-Project PTE NOx, tpy**	**Increase in NOx, tpy**	**Baseline Actual SO_2 (95-96 Avg), tpy**	**Post-Project PTE SO_2, tpy**	**Increase in SO_2, tpy**	**Baseline Actual PM (95-96 Avg), tpy**	**Post-Project PTE PM, tpy**	**Increase in PM, tpy**
Hunter Unit 1								
6,993	9,264	**2,271**	2,534	4,323	**1,789**	651	1,029	**378**
Hunter Unit 2								
6,672	9,264	2,592	2,404	4,323	**1,919**	597	1,029	**433**
Hunter Unit 3								
6,273	9,873	**3,600**	1,206	2,146	**940**	257	429	**173**
Hunter Plant								
19,937	28,400	**8,463**	6,144	10,792	**4,648**	1,505	2,488	**983**
Contemporaneous and Creditable Emission Decreases								
		0			**0**			**0**
Contemporaneous and Creditable Emission Increases								
		0			**0**			**46.6**
Net Emissions Increase due to 1997-1999 Hunter Projects at Hunter Plant								
		NOx			SO_2			**PM**
		8,463			**4,648**			**1,029.5**

[16] Note that this table is a reprint of Table 15 from Sierra Club's June 11, 2021 Comment Letter on the 2021 Hunter Title V Permit Reopening at 35 (Ex. 2). This table reflects the average annual actual emissions for the two years prior to the 1997-1999 Hunter projects as reported in PacifiCorp's Hunter Emissions Inventories 1995 and 1996 (Exs. 14 and 15). This table also reflects post-project potential to emit calculated based on PacifiCorp's reported post-project hourly heat input from its August 1997 Notice of Intent at pdf page 12 (Ex. 9), and the reduced lb/MMBtu emission limits requested by PacifiCorp in its August 1997 Notice of Intent in Table 4 at pdf page 6 (Ex. 9) and that were imposed by UDAQ in its 1997 Approval Orders (November 20, 1997 Approval Order DAQE-1099-97 at 3-4 (Ex. 10) and December 18, 1997 Approval Order DAQE-1189-97 at 2-3 (Ex. 11)). And, for PM, the post change emissions include the creditable emissions increases reported in PacifiCorp's August 1997 Notice of Intent and listed in Table 5 above).

Thus, based on the emissions data laid out above, the 1997-1999 Hunter projects should have been projected to result in significant net emission increases of NOx, SO_2, and PM at each Hunter Units 1, 2, and 3 because the net emissions increase at the plant (and at each Hunter unit) exceeds the "significant" emissions level of 40 tons per year for NOx and for SO_2 and of 25 tons per year for PM. Therefore, the 1997-1999 Hunter projects should have been permitted as a major modification for NOx, SO_2, and PM under Utah's PSD permitting regulations under the Utah SIP in effect at the time. UDAQ unlawfully and improperly permitted the projects as exempt from PSD permitting requirements.

3. *The 1997-1999 Hunter Projects Actually Resulted in Significant Net Emission Increases in at Least NOx and SO_2 Emissions After the Projects Were Completed.*

UDAQ included in its permitting record PacifiCorp's Emission Inventory reports for the two years prior to the Hunter projects (i.e., 1995 and 1996) and for five years after the projects (i.e., 2000-2004). *See* Attachments 5 through 11 of Utah's Hunter Title V Permit documentation files. This data appears to be based on total tons of coal burned and average coal characteristics, and lb/MMBtu emission rates from CEMs data for NOx and SO_2. *Id.* UDAQ included a summary of that data in its response to EPA's reopening for cause, but UDAQ did not present the data on a unit-by-unit basis. UDAQ also used the years 1993 and 1994 of emission inventory data for baseline emissions, but it did not include the PacifiCorp emission inventory submittal and underlying data in the permit record.[17] The table below, which is a reprint of Table 16 from Sierra Club's June 11, 2021 comments to UDAQ on the draft 2021 Hunter Title V permit

[17] Draft May 2021 Hunter Title V Response to EPA's Reopening for Cause at 12. Given that UDAQ indicates that CEMs were not installed at the Hunter units until 1995 (Draft May 2021 Hunter Title V Response to EPA's Reopening for Cause at 8) and that PacifiCorp based NOx and SO_2 lb/MMBtu emissions rates on CEMs data for its 1995, 1996 and 2000-2004 emission inventories, a comparison to PacifiCorp's reported 1993 and 1994 emissions inventory reports would not likely be as accurate of an analysis.

reopened for cause, Sierra Club, Comment Letter on the 2021 Hunter Title V Permit Reopening, June 11, 2021 at 38 (Ex. 2), evaluates the changes in emissions that actually occurred at each Hunter unit over the five years of post-project emission inventory data as compared to a 1995-1996 annual average emissions based on the Hunter units' emissions inventory data that UDAQ added to the Hunter Title V record.

Table 7. Comparison of Actual 1995-1996 Average Baseline Emissions and Heat Input[18] to Actual Emissions and Heat Input from Coal Over 2000-2005 for the Hunter Plant[19]

Year	**2000**						
Hunter	**NOx Baseline**	**NOx 2000**	**NOx Increase**	**SO_2 Baseline**	**SO_2 2000**	**SO_2 Increase**	**Heat Input Increase (MMBtu/yr)**
Unit 1	6,993	6,580	-412	2,534	2,033	-501	No
Unit 2	6,672	7,098	***426***	2,404	1,813	-591	1,817,898
Unit 3	6,273	7,174	***901***	1,206	1,114	-92	2,012,712
Plant			***914***			-1,185	
Year	**2001**						
Hunter	**NOx Baseline**	**NOx 2001**	**NOx Increase**	**SO_2 Baseline**	**SO_2 2001**	**SO_2 Increase**	**Heat Input Increase (MMBtu/yr)**
Unit 1	6,993	4,132	-2,861	2,534	1,720	-814	No
Unit 2	6,672	6,534	-138	2,404	2,720	***316***	601,758
Unit 3	6,273	7,100	***827***	1,206	1,213	7	1,311,323
Plant			-2,171			-491	
Year	**2002**						
Hunter	**NOx Baseline**	**NOx 2002**	**NOx Increase**	**SO_2 Baseline**	**SO_2 2002**	**SO_2 Increase**	**Heat Input Increase (MMBtu/yr)**
Unit 1	6,993	7,367	***375***	2,534	3,114	***580***	964,418
Unit 2	6,672	5,671	-1,001	2,404	2,543	***139***	No
Unit 3	6,273	6,548	***275***	1,206	1,370	***163***	3,462,811
Plant			-351			***882***	
Year	**2003**						
Hunter	**NOx Baseline**	**NOx 2003**	**NOx Increase**	**SO_2 Baseline**	**SO_2 2003**	**SO_2 Increase**	**Heat Input Increase (MMBtu/yr)**
Unit 1	6,993	7,114	***121***	2,534	2,772	***238***	2,617,057
Unit 2	6,672	5,723	-948	2,404	2,331	-73	377,016
Unit 3	6,273	6,508	***235***	1,206	1,029	-177	3,253,088
Plant			-592			-11	
Year	**2004**						
Hunter	**NOx Baseline**	**NOx 2004**	**NOx Increase**	**SO_2 Baseline**	**SO_2 2004**	**SO_2 Increase**	**Heat Input Increase (MMBtu/yr)**
Unit 1	6,993	5,776	-1,217	2,534	2,338	-196	No
Unit 2	6,672	6,182	-490	2,404	2,402	-2	3,704,868
Unit 3	6,273	6,378	***105***	1,206	987	-219	3,847,179
Plant			-1,602			-418	

[18] Heat input was calculated from the PacifiCorp's Hunter Plant Annual Emissions Inventory reports, based on the product of the annual tons of coal burned per unit and the weighted annual average coal heat value for each unit.
[19] This emissions data is from PacifiCorp's Hunter Plant Annual Emissions Inventory reports that UDAQ included in Attachments 5-11 to the Appendix of the 2021 Hunter Title V permit, and those PacifiCorp reports are attached to this petition as Ex. 14 (1995 Emissions Report), Ex. 15 (1996 Emissions Report), Ex. 17 (2000 Emissions Report), Ex. 18 (2001 Emissions Report), Ex. 19 (2002 Emissions Report), Ex. 20 (2003 Emissions Report), and Ex. 21 (2004 Emissions Report).

As the above table demonstrates, each unit had a significant increase in actual emissions of NOx and SO_2 for at least one of the five years after completion of the Hunter projects in 1999. In addition, each unit had significant increases in annual heat input for most of the years of 2000-2005. Hunter Unit 3 has a significant increase in NOx above the 1995-1996 average NOx emissions for every year during 2000-2005. Further, the Hunter plant had a significant net increase of NOx above 1995-1996 annual average emissions in 2000 and had a significant net increase of SO_2 above 1995-1996 annual average emissions in 2002. As explained in the attached expert report of Joseph Van Gieson, which, in turn, is based on a review of a 1996 PacifiCorp Notice of Intent that UDAQ first included in the Hunter permit record with its responses to Sierra Club's June 11, 2021 comments (i.e., after the close of the public comment period),[20] the 1997-1999 Hunter projects resulted in the NOx and SO_2 emissions increases that actually occurred in at least one of the five years after completion of the projects at Hunter Units 1, 2, and 3. *See* Report of Joseph Van Gieson at 16-17 and at 24-25 (Ex. 23).

The legal significance of the fact that these projects resulted in significant emission increases and significant net emission increases cannot be understated. As EPA has said, "The Act provides ample authority to enforce the major NSR requirements if your physical or operational change results in a significant net emissions increase at your major stationary source." *See, e.g.* 42 U.S.C. § 7411(a)(4) ("The term 'modification' means any physical change in, or change in the method of operation of, a stationary source ***which increases*** the amount of any air pollutant emitted by such source.").

[20] As previously explained in this petition, Sierra Club had never reviewed the 1996 PacifiCorp Notice of Intent and never had a chance to comment on it until it was made available in Exhibit 1 to UDAQ's Response to Comments in October 2021 (Ex. 7 to this Petition). The 1996 Notice of Intent has much more detail on the physical and operational changes of the 1997-1999 Hunter projects at issue in this petition, and Sierra Club finds it provides support for its claim that there were physical and/or operational changes to the Hunter boilers associated with the 1997-1999 Hunter projects that were related to the projected heat input (and thus emission) increases and that were also related to the actual emission increases.

4. *Summary: The Hunter Title V Permit Does Not Assure Compliance with the Applicable PSD Permitting Requirements of the Utah SIP for the Major Modifications that Occurred at the Hunter Plant Due to the 1997-1999 Hunter Projects.*

It must be noted that PacifiCorp never claimed that the projects at issue were routine maintenance, repair, or replacement. *United States v. Cinergy*, 2006 WL 372726, at *4 (S.D. Ind. Feb. 16, 2006) ("The party claiming the benefit of an exemption to compliance with a statute bears the burden of proof as to the exemption.") (*citing United States v. First City Nat'l Bank of Houston*, 386 U.S. 361, 366 (1967)); *Ohio Edison*, 276 F. Supp. 2d, 829, 856 (S.D. Ohio 2003); *Sierra Club v. Morgan*, No. 07-C-251-S 2007 U.S. Dist. LEXIS 82760, at *34 (W.D. Wis. 2007); *Nat'l Parks Conservation Ass'n v. TVA*, 618 F. Supp. 2d 815, 824 (E.D. Tenn. 2009) ("Defendant TVA bears the burden of proof as to the applicability of the RMRR exception in this case."); *United States v. E. Ky. Power Coop., Inc.*, 498 F. Supp. 2d 976, 995 (E.D. Ky. 2007). *See also* 40 C.F.R. § 70.5(c)(6).

Furthermore, UDAQ did not indicate in its New/Modified Source Plan Review that any of the Hunter projects qualified for this exception." Indeed, Sierra Club explained why the 1997-1999 Hunter projects would not be considered routine maintenance, repair, or replacement in its June 11, 2021 comment letter, Sierra Club, Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) at 10 (Ex. 2), and in its November 13, 2015 comment letter. Sierra Club, Comments on the PacifiCorp-Hunter Power Plant DRAFT Title V Renewal Permit (Permit Number 1500101002-Draft), submitted to UDAQ on November 13, 2015, at 17-20 (Ex. 4).

Among other reasons why the 1997-1999 Hunter projects would not be considered to be routine maintenance, repair, or replacement, EPA has found that projects that increase efficiency (which typically leads to increased capacity utilization) or that increase capacity are not considered to be routine maintenance, repair, or replacement.[21] Indeed, the projects at issue are quite similar, and yet more extensive, than the project EPA evaluated and found not to be routine maintenance in the Detroit Edison Applicability Determination. *Id*. As previously noted, PacifiCorp stated in its August 1997 Notice of Intent, that, although "[m]any of the projects, in and of themselves, could not cause an increase in emissions...as a whole, the upgrades may increase the actual capacity and capacity utilization of the boilers." *See* August 18, 1997 NOI for Hunter Plant at 1. Given that the projects as a whole could increase capacity and capacity utilization of Hunter Units 1, 2 and 3, the projects could not reasonably be considered to be routine maintenance, repair, or replacement under EPA's four factor analysis.

Based on an evaluation of pre-project actual emissions to post-project allowable emissions, the 1997-1999 Hunter projects should have been projected to result in significant emissions increases and significant net emission increase of NOx, SO_2, and PM under the PSD regulations of the Utah SIP as in effect at the time, the Hunter Title V permit is deficient for failing to include applicable PSD requirements that apply to Hunter Units 1, 2, and 3. Further, the 1997-1999 Hunter projects actually resulted in significant emission increases and significant net emission increases at the Hunter plant in at least one of the five years after completion of the projects for NOx and SO_2. Accordingly, the 2021 Hunter Title V permit fails to ensure compliance with all applicable requirements because it fails to ensure compliance with the PSD permitting requirements of the Utah SIP. Such requirements include emission limits reflective of BACT at Hunter Units 1, 2, and 3 for NOx, SO_2, and PM. In addition, as part of the permit process, PacifiCorp would need to demonstrate that the facility would not cause or contribute to a violation of any national ambient air quality standard (NAAQS) or PSD increments, or

[21] *See, e.g.*, May 23, 2000 letter from EPA to Henry Nickel regarding a turbine upgrade at Detroit Edison's Monroe power plant, available at https://www.epa.gov/sites/default/files/2015-07/documents/detedisn.pdf.

adversely impact air quality related values (including visibility) of any Class I area. Utah Air Conservation Regulation R307-405-11, R307-405-12, R307-405-16, and R307-405-17. The SIP-approved versions of these rules are , available at https://www.epa.gov/system/files/documents/2021-09/table-c-ut.pdf#R307-405.

As part of these analyses, additional emission limits may need to be imposed, including on short term emission rates to provide the short-term ambient air standards such as the 1-hour SO_2 and NO2 NAAQS,[22] the 3-hour average and 24-hour average SO_2 increments (Class I and Class II), and visibility.

All of the above information was presented to UDAQ in Sierra Club's June 11, 2021 comment letter on Draft Hunter Title V Permit No. 1500101004-DRAFT. *See* Sierra Club, Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT), Ex. 2 to this petition. These arguments were also made to UDAQ in its November 13, 2015 comments submitted on the draft 2015 Hunter Title V renewal permit, *see* Sierra Club, Comments on the PacifiCorp-Hunter Power Plant DRAFT Title V Renewal Permit (Permit Number 1500101002-Draft), submitted to UDAQ on November 13, 2015, at 6-49 (Ex. 4 to this petition), which EPA refers to in its 2021 Order reopening the Hunter Title V permit for cause. EPA, Order Denying Petitions for Objection to Permits and Reopening Permit for Cause, issued 1/13/2021, at 16 (Ex. 3 to this petition). Although UDAQ has provided responses to Sierra Club's 2015 comments in its 2021 Hunter Title V permit Appendix and although UDAQ has provided responses to Sierra Club's June 11, 2021 comments on its 2021 Hunter Title V Permit response to the reopening for cause with its submittal of a proposed permit to EPA, UDAQ, Response to Sierra Club's Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit

[22] As discussed in Section V of Sierra Club's November 13, 2015 Comments to UDAQ, modeling of the Hunter plant's allowable SO_2 emissions has shown a problem complying with the 1-hour SO_2 NAAQS. (Ex. 4).

(Permit No. 1500101004-DRAFT) with Utah's Response to EPA's January 13, 2021 Reopening for Cause (dated June 11, 2021) (Ex. 7), UDAQ has failed to provide a sufficient legal or technical basis for finding that the 1997-1999 projects at the Hunter Power Plant were properly exempted from PSD permitting requirements including, but not limited to, imposition of BACT for NOx, SO_2, and PM at Hunter Units 1, 2, and 3. In the next section, Sierra Club explains UDAQ's rationale for its 1997 permit action on the 1997-1999 Hunter projects and why UDAQ's justification for finding the 1997-1999 Hunter projects as exempt from PSD permitting did not comply with the applicable requirements of the Utah SIP in effect at the time of the projects.

II. UDAQ's Rationale for Finding the Hunter 1997-1999 Projects as Exempt from PSD Permitting Requirements is Legally and Technically Flawed and Is Not Otherwise Justified.

This section shows why UDAQ's justification for not considering the 1997-1999 Hunter projects as subject to PSD permitting was legally and technically wrong.

A. <u>UDAQ was neither Legally nor Technically Justified in Relying on Allowable Emissions to Represent Pre-Project Actual Emissions in its PSD Applicability Analysis for the 1997-1999 Hunter Projects.</u>

In its revised Hunter Title V Permit responding to EPA's reopening for cause, UDAQ justifies its use of an allowable emissions baseline in reviewing the 1997-1999 Hunter projects for the following reasons: 1) the state is allowed to presume that "source-specific allowable emissions" are equivalent to actual emissions under the definition of "actual emissions" in its SIP as in effect at the time; 2) that the EPA's October 1990 New Source Review Workshop Manual also allowed for use of source-specific allowable emissions in "limited circumstances, where sufficient representative operating data do not exist;" and 3) that the limitations on use of source-specific allowable emissions in EPA's October 1990 New Source Review Workshop Manual that would preclude UDAQ's reliance on allowable emissions for pre-project emissions were inconsistent with EPA's 1980 New Source Review Workshop Manual.[23]

In its June 11, 2021 comments to UDAQ, Sierra Club commented to UDAQ that first, "source-specific allowable emissions" did not exist for NOx and PM at Hunter Units 1 and 2 because the limits imposed on the units were the requirements of the New Source Performance Standards (NSPS) Subpart D. Second, UDAQ did not use "source-specific allowable emissions" for SO_2 at Hunter Units 1, 2, or 3, which were each subject to SO_2 removal efficiency requirements in their permits that were more stringent than the lb/MMBtu emission limits relied upon by UDAQ. Third, UDAQ could not lawfully use allowable emissions in determining the "net emissions increase" from the 1997-1999 Hunter projects which included pollution control projects for NOx. Fourth, UDAQ also could not lawfully use allowable emissions in determining the "net emissions increase" for NOx, SO_2 and PM due to PacifiCorp requesting reduced emission limits to avoid PSD review for NOx, SO_2, and PM. Finally, PacifiCorp's assumption that allowable emissions equate to actual emissions should have been rejected by UDAQ because actual emissions from Hunter Units 1, 2, and 3 were much lower than allowable emissions for NOx, SO_2, and PM. *See* Sierra Club, Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) with Utah's Response to EPA's January 13, 2021 Reopening for Cause, submitted to UDAQ June 11, 2021, at 12-20 (Ex. 2).

UDAQ's responses to Sierra Club's comments were that 1) it evaluated applicability to PSD using allowable emissions in a "Step 1" applicability test and determined that no emission increase would occur, thus it did not need to evaluate (or be bound by the limitations of) the "net emissions increase" from the 1997-1999 Hunter projects, UDAQ, Response to Sierra Club's

[23] 2021 Hunter Title V Permit, Appendix at 8-9 (Ex. 1 at pdf pages 72-73).

Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT at 4 (UDAQ Response to Comment #3) (Ex. 7); 2) the allowable emissions used by UDAQ were "source-specific allowable emissions" because they were required in state permits, regardless of the fact that Unit 1 and 2's emission limits were the same as the NSPS Subpart D emission limits, *id.* at 7 (UDAQ Response to Comment #6); 3) it relied on the lb/MMBtu emission limits for SO_2 rather than the SO_2 removal efficiency requirements applicable to Hunter Units 1, 2, and 3 because the lb/MMBtu limits were "independent of the coal sulfur content," *id.* at 6 (UDAQ Response to Comment #5); and 4) determining an actual emission baseline would have required a "subjective analysis using multiple unreliable data sets." *Id.* at 5 (UDAQ Response to Comment #4). An additional argument made by UDAQ was that, if it used a true actual emissions baseline, it would have also had to apply an "actual-to-future actual" emissions PSD applicability test, rather than following the "actual-to-potential" test that it purportedly followed (substituting "allowable emissions" for pre-project actual emissions). *Id.* at 7 (UDAQ Response to Comment #7).

UDAQ's justification for using an allowable emissions baseline for reviewing the 1997-1999 Hunter projects is wrong as a matter of law, inconsistent with EPA policy, and not technically justified.

1. *The 1997-1999 Hunter Projects Included Pollution Reduction Projects and Requested Reductions in Enforceable Emission Limits Which Can Only Be Taken Into Account in an Evaluation of "Net Emissions Increase," and the Definition of "Net Emissions Increase" Precluded the Use of an Allowable Emissions Baseline for the Hunter Projects.*

UDAQ has stated that the 1997-1999 Hunter projects included "[t]hree pollution control projects: the installation of overfire air ports at Unit 3, and the burner and windbox changes at Units #1 and #2." 2021 Hunter Title V Permit, Appendix at 5 (UDAQ Response to Comment

#1). Indeed, PacifiCorp's 1997 Notice of Intent listed "overfire air ports for added NOx control" as among the projects for Hunter Unit 3 and "NOx control project including burner and/or windbox changes" as among the projects for Hunter Units 1 and 2. August 18, 1997 PacifiCorp Notice of Intent at pdf page 3 (Table 1), Ex. 9. *See also* 2021 Hunter Title V Permit, Appendix at 5 (pdf page 69 of Ex. 1). In addition, PacifiCorp requested, and UDAQ imposed, reduced emission limits on the Hunter units' potential to emit to ensure no significant increase in emissions with the 1997-1999 Hunter projects. *Id.* at 2; *see also* UDAQ New/Modified Source Plan Review at 3, 4-5 (pdf pages 11-13 of Ex. 11).[24] These are undisputed facts.

In order to take into account emission decreases to offset the emission increases from a project, the requirements of the definition of "net emissions increase" must be met. Specifically, the definition of "net emissions increase" in the Utah SIP states that an emission decrease is creditable only if emissions will be reduced from the lower of actual or allowable emissions. Specifically, Section 2.E.(1) states: "A decrease in actual emissions is creditable only to the extent that: (1) The old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions." *See* section 2.E.(1) of the definition of "net emissions increase" in Utah Air Conservation Regulation R307-1-1 as in effect on 1/1/95 (Ex. 5). The definition of "net emissions increase" in the federal PSD rules has the same limitation on creditable emission reductions. 40 CFR 52.21 (b)(3)(vi)(a). *See also* 40 C.F.R. 51.166(b)(3)(vi)(a) (requirements that states' PSD SIPs must meet). The actual emissions

[24]Note that UDAQ, in its October 2021 Response to Sierra Club's June 11, 2021 comment letter, claims that it is "inaccurate to say that PacifiCorp 'requested' UDAQ to account for emission decreases." UDAQ, Response to Sierra Club's Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) (dated June 11, 2021), at 4 (Ex. 7). Yet, the 1997 Approval Orders for the 1997-1999 Hunter projects specifically state that "PacifiCorp is requesting that additional enforceable emission limits be established" and that the "net effect of [the 1997-1999 projects] could be an increase in emissions, hence the newly requested limits to insure an emission decrease." *See* November 1997 Approval Order at 3 and December 1997 Approval Order at 3 (Exs. 10 and 11).

of the Hunter units were lower than the allowable emissions before the Hunter projects, as demonstrated in Table 8 below.

Table 8. PacifiCorp's Reported Actual Emissions for 1995 and 1996 and PacifiCorp's and UDAQ's Allowable Emissions for Hunter Units 1, 2, and 3[25]

Hunter Unit 1						
Source of Data	**Year**	**PM, ton/year**	**SO2, ton/year**	**NOx, ton/year**	**Coal Usage, ton/yr**	**Heat Input, MMBtu/yr**
PacifiCorp Emissions Report	1995	511.4	2,406.5	7,166.1	1,409,836	32,367,015
PacifiCorp Emissions Report	1996	791.35	2,661.18	6,819.27	1,436,921	33,264,721
Two Year Average	**1995-1996 Actual Emissions Baseline**	**651**	**2,534**	**6,993**	**1,423,379**	**32,815,868**
PacifiCorp's August 1997 Notice of Intent		*598*	*4,373*	*12,755*	*1,586,072*	*36,440,000*
Hunter Unit 2						
Source of Data	**Year**	**PM, ton/year**	**SO2, ton/year**	**NOx, ton/year**	**Coal Usage, ton/yr**	**Heat Input, MMBtu/yr**
PacifiCorp Emissions Report	1995	504.5	2,295.1	7,062	1,429,474	32,694,929
PacifiCorp Emissions Report	1996	689.09	2,512.64	6,281.59	1,369,851	31,407,944
Two Year Average	**1995-1996 Actual Emissions Baseline**	**597**	**2,404**	**6,672**	**1,399,663**	**32,051,437**
PacifiCorp's August 1997 Notice of Intent		*598*	*4,373*	*12,755*	*1,586,072*	*36,440,000*
Hunter Unit 3						
Source of Data	**Year**	**PM, ton/year**	**SO2, ton/year**	**NOx, ton/year**	**Coal Usage, ton/yr**	**Heat Input, MMBtu/yr**
PacifiCorp Emissions Report	1995	295.4	1,312.5	6,418.2	1,542,312	35,186,306
PacifiCorp Emissions Report	1996	218.07	1,099.76	6,127.26	1,382,151	31,421,821
Two Year Average	**1995-1996 Actual Emissions Baseline**	**257**	**1,206**	**6,273**	**1,462,232**	**33,304,063**
PacifiCorp's August 1997 Notice of Intent		*503*	*2,186*	*10,021*	*1,586,072*	*36,440,000*

Thus, to create creditable emission reductions to ensure that there would not be a significant net emissions increase as a result of the 1997-1999 Hunter projects, the reduced emission limits requested by PacifiCorp and imposed by UDAQ in its 1997 Approval Orders

[25] The data for this table are from 1) Hunter Emissions Inventory 1995 (Ex. 14), 2) Hunter Emissions Inventory 1996 (Ex. 15), and 3) PacifiCorp's August 18, 1997 Notice of Intent at pdf pp. 8-9 (EPA Baseline Emissions) (Ex. 9). This table is a compilation of Tables 3 and 4 from Sierra Club's June 11, 2021 Comment Letter to UDAQ on its Draft 2021 Hunter Title V Permit Response to EPA's Reopening for Cause (see Ex. 2 at 16-17).

would need to reduce emissions below the “old” (i.e., pre-project) level of actual emissions in order for the reduced emissions to be creditable to ensure that no significant net emissions increase would be allowed from the 1997-1999 Hunter projects. As shown in Table 4 above, the “new” level of actual emissions (i.e., post-project potential to emit) was significantly higher than the “old” level of actual emissions, thus UDAQ’s lowered emission limits imposed in the 1997 Approval Orders failed to create creditable emission reductions to allow the 1997-1999 Hunter projects to “net out” of PSD review. *See* November 20, 1997 Approval Order DAQE-1099-97, Condition 5 at pp. 3-4 (Ex. 10) and December 18, 1997 Approval Order DAQE-1189-97, Condition 5 at pp. 4-5 (Ex. 11).

UDAQ’s rebuttal to this clear legal argument was that it never got to the point of determining the “net emissions increase” from the 1997-1999 Hunter projects because it found that the projects would not result in a significant emissions increase in a “Step one” PSD applicability analysis. UDAQ Response to Sierra Club’s Comments at 4 (UDAQ Response to Comment #3), Ex. 7. Specifically, UDAQ states in its response to comments that Sierra Club:

> …incorrectly assumes that UDAQ conducting a netting analysis (calculation of significant net emissions increase), which is the second step of the PSD-applicability analysis. UDAQ did not perform netting, as it was not required due to the conclusions UDAQ reached in the first step of the analysis…At step one of its 1997 PSD nonapplicability determination, UDAQ applied the allowable emissions presumption in the pre-project emissions calculation. UDAQ then concluded that for each pollutant, the post-project actual emissions would not exceed the pre-project actual emissions by a significant amount. In the absence of a significant increase of any pollutant, UDAQ was not required to reach step two to determine significant net emissions increases. Consequently, Sierra Club’s comment regarding the use of source-specific allowable emissions and its conflict with the principles of the netting analysis in step two does not apply to the analysis UDAQ conducted.

Id. at 3-4.

For the reasons explained in the subsections below, in this case, it was improper to use an allowable emissions baseline in Step One. But even if that had been appropriate, in Step One, under the rules that applied at the time, it was inappropriate to consider emission reductions at all. Table 9 below shows that if UDAQ had applied Step One correctly, even using an allowable emissions baseline, an emissions increase results.

Table 9. Step 1 Analysis of Emission Increases from the 1997-1999 Hunter Projects Using UDAQ's Allowable Emissions Baseline But Only Considering the Emission Increases Proposed in PacifiCorp's August 1997 Notice of Intent[26, 27]

UDAQ's Baseline NOx (Allowable Emissions), tpy	Post-Project Potential Increased NOx, tpy	Increase in NOx, tpy	UDAQ's Baseline SO2 (Allowable Emissions), tpy	Post-Project Potential Increased SO2, tpy	Increase in SO2, tpy	UDAQ's Baseline PM (Allowable Emissions), tpy	Post-Project Potential Increased PM, tpy	Increase in PM, tpy
Hunter Unit 1								
12,755	14,410	**1,655**	4,373	4,941	**568**	893	1,009	**116**
Hunter Unit 2								
12,755	14,410	**1,655**	4,373	4,941	**568**	893	1,009	**116**
Hunter Unit 3								
10,021	11,804	**10,021**	2,186	2,575	**389**	547	644	**97**
Hunter Plant								
35,531	40,625	**5,094**	10,932	12,457	**1,525**	1,669	2,661	**328**

Furthermore, as for the emission reduction projects undertaken by PacifiCorp undertaken at the same time, proper consideration of those in a Step Two netting analysis still yields a significant net emissions increase. This conclusion is demonstrated in Table 6 above.

[26] UDAQ's Baseline (Allowable Emissions) are from PacifiCorp's August 18, 1997 Notice of Intent at pdf page 9 (Hunter Plant EPA Baseline Emissions), Ex. 9. Post Project Potential Increased emissions are calculated from the increased hourly heat input of each Hunter Unit listed in PacifiCorp's August 18, 1997 Notice of Intent at pdf page 12 (Hunter Plant Future Potential Emissions) and multiplying that heat input by the baseline lb/MMBtu "emission rates" listed at pdf page 9 of the PacifiCorp August 1997 Notice of Intent and an assumed 8,760 hours of operation per year, Ex. 9. The increased emissions provided in this table are the increases due to the hourly heat input increases (from 4,160 to 4,700 MMBtu/hour at Hunter Units 1 and 2 (each) and from 4,160 to 4,900 MMBtu/hour at Hunter Unit 3).

[27] Note that the table is a new analysis not previously submitted to UDAQ in comments on the Hunter Title V permit, because Sierra Club was not aware that UDAQ was claiming to take into account allowable emission decreases in a Step One PSD applicability analysis for the 1997-1999 Hunter projects until UDAQ stated as such in its October 2021 Response to Sierra Club's June 11, 2021 comments (at pages 3-4 of Ex. 7 to this Petition). UDAQ did not previously indicate that this was its justification for its applicability determination until it provided its response to comments on the 2021 Hunter Title V permit in October of 2020, well after the public comment period on the 2021 Hunter Title V Permit which ended on June 11, 2021. Thus, it was not practicable to raise this issue during the comment period.

From a regulatory perspective, EPA has always had a two-step process for determining whether a major modification has occurred: First, determine whether the *increase* in emissions from a proposed physical change/change in the method of operation would be significant and, if so, determine whether a significant *net* emissions increase will occur.[28] This two-step applicability process was implemented through policy until 2002, when EPA codified the two step applicability process in its rules. *Id.* EPA's policy at the time of the 1997-1999 Hunter projects required that a permitting authority must only include emission increases in the first step of the emissions increase analysis and, if the emission increase was greater than significant emission thresholds, then an evaluation of net emissions increase considering all contemporaneous and creditable emission increases and decreases was required. Specifically, in a September 18, 1989 policy memorandum, EPA states that its "historic policy has been not to consider accumulated emissions from a series of small (i.e., less than significant) emissions increases if the emissions increase from the proposed modification to the source is, standing alone without regard to any decreases, less than significant." *See* September 18, 1989 EPA Memorandum "Request for Clarification of Policy Regarding the 'Net Emissions Increase'" at 1-2, available at https://www.epa.gov/sites/default/files/2015-07/documents/request.pdf. In addition, EPA states in its 1990 New Source Review Workshop Manual that:

> [i]t is important to note that when any emission decrease is claimed, including those associated with the proposed modification), all source-wide creditable and contemporaneous emission increases and decreases of the pollutant subject to netting must be included in the PSD applicability determination.

EPA, New Source Review Workshop Manual, October 1990, at A.36.

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[28] As discussed in 67 Fed. Reg. 80,186 at 80190 (December 31, 2002). *See also* January 22, 1981 EPA Memorandum entitled "PSD Applicability" in which EPA stated that "EPA is interpreting the term 'net emissions increase' as any significant increase in actual emissions from a physical change or change in the method of operation and any other creditable contemporaneous increases or decreases in actual emissions," available at https://www.epa.gov/sites/production/files/2015-07/documents/crgilinc.pdf. *See also* September 18, 1989 EPA Memorandum "Request for Clarification of Policy Regarding the 'Net Emissions Increase'"

EPA's two step PSD applicability analysis was formally codified into its PSD rules in a December 31, 2002 rulemaking. 67 Fed. Reg. 80,186 at 80,190, 80,248, and 80,260 (December 31, 2002). When EPA promulgated the revisions to the PSD regulations that specified the two step applicability process, EPA stated "[w]e have revised the definition of major modification to clarify what has always been our policy—that determining whether a major modification has occurred is a two-step process." 67 Fed. Reg. 80,186 at 80190 (December 31, 2002). EPA continued to implement the Step One analysis as only allowing for consideration of emissions increases, and not emission decreases, in the Step One analysis until it changed its PSD regulations in November of 2020.[29]

While EPA issued a guidance memo on March 3, 2018 that would for the first time allow for considering emission decreases in a Step One analysis, that guidance memo made clear that it was 1) an interpretation of EPA's PSD rules as revised on December 31, 2002 (which first codified the Step One analysis), and 2) that it was a new interpretation based on the language of the 2002 PSD rule revisions. (March 13, 2018 EPA Memo with Subject: "Project Emissions Accounting under the New Source Review Preconstruction Permitting Program," at 1-2, and 6-7). Further, as stated in the March 30, 2010 HOVENSA memo, EPA never took any public comment or otherwise notified the public in its promulgation of the December 31, 2002 PSD regulation revisions that it was making a change in its longstanding policy that prohibits a source from taking into account emission decreases along with emission increases in a Step One PSD applicability analysis. On November 24, 2020, EPA formerly adopted a regulatory revision to its

[29] *See*, e.g., March 30, 2010 EPA Memo with subject "HOVENSA Gas Turbine Nitrogen Oxides (GT NOx) Prevention of Significant Deterioration (PSD) Permit application – Emission Calculation Clarification," available at https://www.epa.gov/sites/default/files/2015-07/documents/stp1net.pdf; August 26, 2011 EPA letter to the Semiconductor Industry Association, at 7 (making clear that "project netting" is not allowed under the regulations), available at https://www.epa.gov/sites/default/files/2015-07/documents/semiconpsd.pdf.

PSD regulations to allow for the consideration of emission decrease in a Step One PSD applicability analysis. 85 Fed. Reg. 74,890 (November 24, 2020). That significant regulatory revision did not become effective until December 24, 2020. See 40 C.F.R. 51.166(a)(7)(g) and 52.21(a)(2)(iv)(g) as in effect on and after December 24, 2020.

EPA's November 2020 rulemaking did not apply to either federal or Utah rules at the time of the 1997-1999 Hunter projects. Moreover, there is one major difference between the Step One emissions analysis under the federal PSD regulations in effect since December 30, 2002 compared to the first step applicability analysis under the federal PSD rules prior to EPA's 2002 PSD regulation revisions. That is, EPA's PSD permitting rules, as revised in 2002, eliminated the ability for a state to assume source-specific allowable emissions were equivalent to actual emissions for determining PSD applicability. Specifically, EPA's PSD regulations have, since 2002, required that the pre-project emissions are based on the "baseline actual emissions," and the definition of "baseline actual emissions" does not allow the "source-specific allowable emissions" to be assumed to be equivalent to actual emissions of a source. See 40 C.F.R. 51.166(b)(47) and 52.21(b)(48). This definition is currently incorporated into Utah's SIP at R307-405-3(1) of the Utah Air Conservation Regulations (effective 2/2/12), 40 C.F.R. 52.2320(c).

Not only was UDAQ's applicability analysis inconsistent with PSD regulations in the Utah SIP at the time of the Hunter projects and corresponding EPA policy, but UDAQ's applicability methodology allowed actual significant increases in emissions at each Hunter unit and at the plant as a whole. As shown in Table 7, significant increases in actual emissions occurred for both NOx and SO2 at all three Hunter units and at the Hunter facility in at least one of the five years after construction of the 1997-1999 Hunter projects. See also Sierra Club, Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) with Utah's Response to EPA's January 13, 2021 Reopening for Cause, submitted to UDAQ June 11, 2021, at 38 (Ex. 2).

For the reasons explained above, UDAQ could not lawfully consider emission decreases in a Step One PSD emission increase analysis under the existing Utah SIP at the time for the 1997-1999 Hunter projects or under federal PSD regulations or policy that existed at the time. By relying on a "Step One" analysis to take into account emission increase and emission decreases and by relying on an allowable emissions baseline, UDAQ was essentially applying an "allowable-to-allowable" emissions increase analysis. EPA took public comment on such an applicability approach in 1996, but EPA has never adopted this PSD applicability methodology as part of its regulations. *See* 61 Fed. Reg. 38,250, 38,268-70 (July 23, 1996) and 67 Fed. Reg. 80,186 at 80,189, 80, and 204-06 (December 31, 2002). EPA must now allow it here.

2. *The Allowable Emissions Baseline Relied on by UDAQ in its PSD Nonapplicability Analysis for the 1997-1999 Hunter Projects Were Not "Source-Specific Allowable Emissions" for the Hunter Units.*

There are other reasons why it was improper for UDAQ to use allowable emissions for baseline. For one thing, such an approach fails to meet the requirements of Utah's definition of "actual emissions," which only allows UDAQ to presume that "source-specific allowable emissions" are equivalent to actual emissions. *See* definition of "actual emissions" in Utah Air Conservation Regulations Regulation R307-1-1 as in effect on 1/1/95 (Ex. 5). As Sierra Club stated in its June 11, 2021 comments to UDAQ, "source-specific" allowable emissions did not exist for NOx and PM at Hunter Units 1 and 2, and UDAQ did not use the "source-specific" allowable emission to reflect pre-project SO2 emissions for Hunter Unit 1, 2, or 3. Sierra Club, Comment Letter on the 2021 Hunter Title V Permit Reopening, June 11, 2021, at 12-13 (Ex. 2).

EPA has defined what it meant by the term "source-specific allowable emissions" in the August 7, 1980 PSD rulemaking in which the relevant definition of "actual emissions" was promulgated by EPA as part of the Federal PSD program. EPA also defined the limitations on using source-specific allowable emissions to reflect actual emissions. Specifically, EPA states the following:

> Source-specific requirements include permits that specify operating conditions for an individual source, such as PSD permits, state NSR permits issued in accordance with § 51.18(j) and other § 51.18 programs, including Appendix S (the Offset Ruling), and SIP emissions limitations established for individual sources. <u>The presumption that federally enforceable source-specific requirements correctly reflect actual operating conditions should be rejected by EPA or a state, if reliable evidence is available which shows that actual emissions differ from the level established in the SIP or the permit</u>.
>
> EPA believes two factors support the presumption that source-specific requirements represent actual source emissions. First, since the requirements are tailored to the design and operation of the source which are agreed on by the source and the reviewing authority, EPA believes it is generally appropriate to presume the source will operate and emit at the allowed levels. Second, the presumption maintains the integrity of the PSD and NSR systems and the SIP process. When EPA or a state devotes the resources necessary to develop source-specific emissions limitations, EPA believes it is reasonable to presume those limitations closely reflect actual source operation.

45 Fed. Reg. 52,676 at 52,718 (Aug. 7, 1980) (emphasis added).

In the Appendix to the 2021 Hunter Title V Permit responding to EPA's reopening for cause, UDAQ does not cite the August 7, 1980 preamble language and instead cites EPA's 1980 PSD Workshop Manual as explaining what source-specific allowable emissions were and when they could be used. Regardless, the quote from the 1980 PSD Workshop Manual that UDAQ cites also defines source-specific allowable emissions as those emissions based on "permitted allowable emissions determined on a site-specific, case-by-case basis such as those in PSD permits," and it states that allowable emissions should not be used when allowable emissions exceed actual emissions. 2021 Hunter Title V Permit, Appendix at 8 -9 (pdf pages 72 to 73 of

Ex. 1). *See also* EPA, 1980 PSD Workshop Manual, October 1980, at I-A-13 to I-A-14, available at https://www.epa.gov/sites/default/files/2015-07/documents/1980wman.pdf.

Utah's definition of "allowable emissions" also indicates that emission limits have to be established in a Utah permit ("Approval Order"). Specifically, Utah's rules as in effect at the time of the 1997-1999 Hunter Projects defined "allowable emissions" as:

> the emission rate of a source calculated using the maximum rated capacity of the source (unless the source is subject to enforceable limits which restrict the operating rate, or hours of operation, or both) <u>and the emission limitation established pursuant to R307-1-3.1.8</u>.

Utah Rule R307-1-1, definition of "allowable emissions" [emphasis added], in effect in 1995 (Ex. 5).

Utah Rule R307-1-3.1.8 as in effect at the time of the 1997-1999 Hunter projects described the requirements the UDAQ Executive Secretary must meet to issue an Approval Order, and the main requirement under which a source-specific emission limitation would be established was under their BACT requirement that applied to all Approval Orders in Rule R307-1-3.1.8.A:

> The Executive Secretary shall issue an approval order if he determines through plan review that the following conditions have been met…A. The degree of pollution control for emissions…is at least best available control technology except as otherwise provided in these regulations.

Rule R307-1-3.1.8.B. provides another set of conditions that the Executive Secretary must ensure that have been met to issue an Approval Order, which include requirements such as the National Standards of Performance for New Stationary Sources (NSPS). However, because those other standards referred to such as the NSPS are established by EPA pursuant to the Clean Air Act, it is clear that the reference in the Utah definition of "allowable emissions" to emission limitations "established pursuant to R307-1-3.1.8" is referring to BACT emission limitations established under R307-1-3.1.8.A. That is because NSPS emission limits are established by EPA, and not established by Utah.

In Sierra Club's June 11, 2021 comments to UDAQ, Sierra Club commented that the emission limits being relied on by UDAQ for Hunter Units 1 and 2 as source-specific allowable emission limits were not "source-specific" designed for each Hunter unit. Instead, they were the "source category-specific" emission limits of the NSPS Subpart D. Sierra Club, Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) with Utah's Response to EPA's January 13, 2021 Reopening for Cause, submitted to UDAQ June 11, 2021 at 13-14 (Ex. 2).

UDAQ's response to Sierra Club's comments was that "[w]hile the state did impose limits equal in stringency to the NSPS limits, this is appropriate because these are the source-specific limits that UDAQ established under Utah Administrative Code R307-1-3.1.8 to govern plant operations. This meant that the limits reflected source-specific allowable emissions for the units and could be properly used for baseline emissions." UDAQ, Response to Sierra Club's Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) at 4-5 (Ex. 7).

UDAQ's argument is without merit. If EPA would have considered the NSPS emission limits as sufficient to be considered "source-specific emission limits," EPA would have listed the NSPS limits as limits that could be relied on as "source-specific emission limits." Instead, EPA referred to source-specific emission limits as limits "that specify operating conditions <u>for an individual source</u>, such as PSD permits, state [new source review] permits…and SIP emissions limitations established <u>for individual sources</u>." 45 Fed. Reg. 52,676 at 52,718 (Aug. 7, 1980) [emphasis added]. The NSPS Subpart D emission limits were established for all "fossil-fuel-fired steam generating units of more than 73 megawatts (MW) heat input rate" that were constructed or modified after August 17, 1971. 40 C.F.R. 60.40(a)(1) and (c).

Thus, the NSPS Subpart D emission limits apply to a very broad category of sources. For example, the Subpart D NSPS emission limitations are not dependent on the type of coal burned, the boiler type, or the existing pollution control equipment that has been installed. The NSPS Subpart D PM emission limit in 40 C.F.R. 60.42(a) of 0.10 lb/MMBtu applies to all coal-fired boilers regardless of whether the boiler is equipped with an electrostatic precipitator or a baghouse. The NSPS Subpart D NOx emission limit in 40 C.F.R. 60.44(a)(3) of 0.70 lb/MMBtu applies to all coal-fired boilers regardless of boiler configuration and whether the boiler burns bituminous or subbituminous coal. As EPA has demonstrated in its guidelines for best available retrofit technology (BART) for existing coal-fired electric utility boilers, the expected NOx rate for different types of boilers that are equipped with combustion controls can vary from 0.15 lb/MMBtu to 0.62 lb/MMBtu based on boiler type (e.g., wet bottom tangential-fired, dry bottom wall-fired, etc.) and coal type (subbituminous or bituminous coal). *See* 40 C.F.R. Part 51, Subpart Y, Guidelines for BART Determinations under the Regional Haze Rule, Section IV.E.5. Nitrogen oxide limits for utility boilers, Table 1. These presumptive BART NOx limits that vary based on boiler type and coal type show how variable NOx emissions can be for a coal-fired boiler (without post-combustion controls) based on these factors. Thus, UDAQ's claims that the NSPS Subpart D limits are "source-specific" emission limits for Hunter Units 1 and 2 based solely on the fact that the emission limits were incorporated into Approval Orders for each Hunter Unit 1 and 2 does not demonstrate that the emission limits of the Unit 1 and 2 Approval Orders were determined on a "site-specific, case-by-case basis" as required by the 1980 EPA PSD Workshop Manual.

In addition, for Hunter Unit 2, the pre-project emissions of NOx were not based on the emission limit in the Approval Order for the unit, which was lower than the applicable NSPS Subpart D emission limit. Specifically, for NOx emissions at Hunter Unit 2, UDAQ and PacifiCorp assumed the NSPS NOx emission limit of 0.70 lb/MMBtu in the PSD applicability analysis. *See* August 18, 1997 Notice of Intent at pdf page 9 (Hunter Plant EPA Baseline Emissions) (Ex. 9). *See also* 2021 Hunter Title V Permit, Appendix at 14 (where UDAQ provides it rationale for using a 0.70 lb/MMBtu NOx limit as allowable emissions for Hunter Unit 2 rather than the 0.49 lb/MMBtu NOx limit that applied in the 1987 Approval Order most recently in effect prior to the 1997-1999 Hunter projects). However, the Approval Order for Hunter Unit 2 in effect at the time of the 1997 Approval Orders authorizing the 1997-1999 Hunter projects mandated a much more stringent NOx limit of 0.49 lb/MMBtu for Hunter Unit 2. *See* July 27, 1987 Approval Order, Hunter Unit 2, Condition 4 at page 3 (Ex. 16). *See also* UDAQ New/Modified Source Plan Review, September 30, 1997, Table 2 at 4-5, which shows the existing Hunter Unit 2 NOx limit as 0.49 lb/MMBtu and the new NOx limits for Hunter Unit 2 of 0.45 lb/MMBtu (12-month rolling average) and 0.70 lb/MMBtu (3-hour averaging period), at pdf page 13 of Ex. 11. Sierra Club discussed this error in PacifiCorp's pre-project baseline emissions in its November 13, 2015 comment letter to UDAQ and pointed out that a comparison of pre-project allowable emissions with the 0.49 lb/MMBtu NOx limit to post-project allowable emissions with the increased hourly heat input and the enforceable NOx limit of 0.45 lb/MMBtu shows that the 1997 Approval Orders would allow for an increase in allowable NOx emissions of 336 tons per year at Hunter Unit 2. Sierra Club, Comments on the PacifiCorp-Hunter Power Plant DRAFT Title V Renewal Permit (Permit Number 1500101002-Draft), submitted to UDAQ on November 13, 2015, at 41-42 (Ex. 4). In the 2021 Hunter Title V Permit Appendix responding to EPA's reopening of the Title V permit for cause, UDAQ responded to that comment and, in doing so, made clear that the NOx limits in the Hunter Unit 2 permit was simply the NSPS limit:

> The 0.49 lb/MMBtu limit [in the 1987 Approval Order] was chosen specifically because it was 70% of the NSPS Subpart D limit of 0.70 lb/MMBtu for NOx, a level at which Hunter Unit 2 would not have been required to install a [continuous emissions monitor (CEM)] as per the subpart. By the time the 1997 Approval Order was issued, PacifiCorp had installed a CEM and appropriately requested that the limit be changed back to the default NSPS level of 0.70 lb/MMBtu, in keeping with the original NSPS requirement.

2021 Hunter Title V Permit No. 1500101004, Appendix responding to EPA's reopening of the permit for cause, 11/19/2021, at 14. Thus, not only did UDAQ not use "source-specific" emission limits for Hunter Units 1 and 2 as baseline emissions (because the emission limits relied on by UDAQ were the NSPS limits and were not "site-specific, case-by-case" emission limits tailored to the design and operation of the units), but UDAQ also ignored an allowable NOx limit in the existing Hunter Unit 2 Approval Order that was much lower than the 0.70 lb/MMBtu NSPS NOx limit that UDAQ relied upon for Hunter Unit 2's source-specific allowable emissions.

3. *UDAQ's Reliance on an Allowable Emissions Baseline for Evaluating PSD Applicability for the 1997-1999 Hunter Projects Was Not Technically Justified under EPA Policy.*

UDAQ's record for the 2021 Hunter Title V Permit responding to EPA's reopening for cause includes actual emissions data for Hunter Units 1, 2, and 3 from PacifiCorp for the two years immediately prior to the 1997-1999 Hunter projects (i.e., 1995 and 1996) as well as for the five years after the projects were completed (2000 to 2004). *See* 2021 Hunter Title V Permit, Appendix at 21-22 with weblinks to PacifiCorp emission inventory reports in Attachments 5-11, and those PacifiCorp reports are attached to this petition as Ex. 14 (1995 Emissions Report), Ex.

15 (1996 Emissions Report), Ex. 17 (2000 Emissions Report), Ex. 18 (2001 Emissions Report), Ex. 19 (2002 Emissions Report), Ex. 20 (2003 Emissions Report), and Ex. 21 (2004 Emissions Report). This data apparently had been provided by PacifiCorp to UDAQ in various formats in response to various requests in the past. In submitting data to UDAQ, PacifiCorp stated the "1995 and 1996 emissions data should suffice to establish the requested baseline." *See* 2021 Hunter Title V Permit, Appendix at 24 with link to Attachment 32, April 2021 Emails Between UDAQ and PacifiCorp Re Emission Inventories attached as Ex. 22. *See also* Ex. 14 (1995 Emissions Report) and Ex. 15 (1996 Emissions Report). A review of that actual emissions inventory data shows that the pre-project actual emissions were much lower than the allowable emissions baseline relied on by UDAQ.

Table 10. Comparison of Pre-Project Average Annual Emissions Baseline (1995 to 1996 Average) to UDAQ's Allowable Emissions Pre-Project Baseline for Hunter Units 1, 2, and 3[30]

Hunter Unit 1				
Source of Data	**Year**	**PM, ton/year**	**SO2, ton/year**	**NOx, ton/year**
PacifiCorp Emission Inventory Reports	**1995-1996 Average Actual Emissions Baseline**	**651**	**2,534**	**6,993**
August 1997 PacifiCorp Notice of Intent	*UDAQ's Allowable Emissions Baseline*	*893*	*4,373*	*12,755*
Hunter Unit 2				
Source of Data	**Year**	**PM, ton/year**	**SO2, ton/year**	**NOx, ton/year**
PacifiCorp Emission Inventory Reports	**1995-1996 Average Actual Emissions Baseline**	**597**	**2,404**	**6,672**
August 1997 PacifiCorp Notice of Intent	*UDAQ's Allowable Emissions Baseline*	*893*	*4,373*	*12,755*
Hunter Unit 3				
Source of Data	**Year**	**PM, ton/year**	**SO2, ton/year**	**NOx, ton/year**
PacifiCorp Emission Inventory Reports	**1995-1996 Average Actual Emissions Baseline**	**257**	**1,206**	**6,273**
August 1997 PacifiCorp Notice of Intent	*UDAQ's Allowable Emissions Baseline*	*547*	*2,186*	*10,021*

As demonstrated by Table 10 above, the annual average actual emissions for the two years preceding the 1997-1999 Hunter projects are much lower than the allowable emissions baseline emissions relied on by UDAQ for evaluating PSD applicability for the 1997-1999 Hunter projects. As previously stated, EPA guidance on using source-specific allowable emissions to reflect pre-project emissions states:

> The presumption that federally enforceable source-specific requirements correctly reflect actual operating conditions should be rejected by EPA or a state, if reliable evidence is available which shows that actual emissions differ from the level established in the SIP or the permit.

45 Fed. Reg. 52,676 at 52,718 (Aug. 7, 1980) (emphasis added). *See also* EPA, PSD Workshop Manual, 1980, at I-A-14 (Allowable emission should not be used when allowable emissions exceed actual emissions); and EPA, New Source Review Workshop Manual, October 1990, at

[30] The data for this table are from 1) Hunter Emissions Inventory 1995 (Ex. 14), 2) Hunter Emissions Inventory 1996 (Ex. 15), and 3) PacifiCorp's August 18, 1997 Notice of Intent at pdf pages 8-9 (EPA Baseline Emissions) (Ex. 9).

A.41 ("[i]n certain limited circumstances, where sufficient representative operating data do not exist to determine historic actual emissions and the reviewing agency has reason to believe that the source is operating at or near its allowable emissions level, the reviewing authority may presume that source-specific allowable emissions [or a fraction thereof] are equivalent to…actual emissions at the unit.") Sierra Club submitted comments to UDAQ making the claims laid out in the above table to show that reliable evidence existed to show that actual emissions were lower than allowable emissions. Sierra Club, Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) with Utah's Response to EPA's January 13, 2021 Reopening for Cause, submitted to UDAQ June 11, 2021, at 16-17 (Ex. 2).

UDAQ's response to Sierra Club's comments was that "Sierra Club is incorrect in that the data it cites are reliable for purposes of quantifying pre-project actual emissions. This is apparent from Sierra Club's lengthy discussion of biases in [continuous emission monitoring system (CEMS)]…."[31]

For the analysis presented in the table above and in Sierra Club's June 11, 2021 comments to UDAQ, Sierra Club used PacifiCorp's 1995 and 1996 emission inventory submittals to UDAQ. PacifiCorp relied on the following data to calculate PM, SO2, and NOx emissions from Hunter Units 1, 2, and 3 for 1995 and 1996:

- Annual coal consumption in tons/year from PacifiCorp's annual production data
- Weighted annual average heating value of the coal in Btu/lb from PacifiCorp's annual production data
- PM lb/MMBtu emission factor based on AP-42, Table 1.1-5, 1/95.[32]
- SO2 and NOx lb/MMBtu emission rates from CEM database, measured values

[31] UDAQ, Response to Sierra Club's Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) with Utah's Response to EPA's January 13, 2021 Reopening for Cause (dated June 11, 2021) at 5 (Ex. 7).

[32] See https://www.epa.gov/sites/default/files/2020-11/documents/ap42_5thed_orig.pdf, for 1/95 version of Table 1.1-5.

See Hunter Emissions Inventory 1995 (Ex. 14) and Hunter Emissions Inventory 1996 (Ex. 15).

Using actual annual coal consumption data and actual weighted annual average heating value of the coal is a reliable method for determining annual heat input to the boilers. Utilities record the actual amount of coal burned and the heating value of the coal because it is a significant operational expense. Further, the Energy Information Administration ("EIA") has been requiring that such data be reported to EIA since 1985. See EIA Form 767 Historical Data files, available at https://www.eia.gov/electricity/data/eia767/. *See also* EIA Form 923 detailed data with previous form data (EIA-906/920), available at https://www.eia.gov/electricity/data/eia767/.

The SO_2 and NOx emission factors were based on CEMs and measured values. Sierra Club's 2015 comment letter to UDAQ did point out how the CEM data required by EPA's acid rain program for coal-fired electric utility boilers like the Hunter plant was known to have a bias due to inaccurate volumetric flow measurements for which EPA did not propose possible fixes to address the bias until mid-1999. *See* Sierra Club's Comments on the PacifiCorp-Hunter Power Plant DRAFT Title V Renewal Permit (Permit Number 1500101002-Draft), submitted to UDAQ on November 13, 2015 at 22-23 (Ex. 4). However, the biases in the flow measurements that existed in the 1990's CEM data for coal-fired power plants like Hunter would not affect the lb/MMBtu emission rates calculated from the CEMs because the volumetric flow measurements would "cancel out" in the calculation of lb/MMBtu emission rates. Specifically, as shown in Table 6 of EPA's Plain English Guide to the Part 75 Rule, June 2009, the equations to calculate SO_2 or NOx mass rate in pound per hour ("lb/hr") and to calculate heat input in MMBtu/hour demonstrate how the flow measurements would "cancel out" in the calculation of lb/MMBtu emission rates:

- SO_2 or NOx mass rate (lb/hr) =

  species-specific conversion constant * hourly average SO2 or NOx concentration (ppmv) * hourly average volumetric flow rate (scfh) * moisture correction term.

- Heat input (mmBtu/hr) =

  the hourly average volumetric flow rate * a moisture correction term)/(Fuel specific F factor * Diluent gas correction term.

- SO_2 or NOx Emission Rate in lb/MMBtu =

  SO_2 or NOx mass rate (lb/hr)/Heat input (MMBtu/hr)

Since the "hourly average volumetric flow rate" is in both the numerator and denominator, the units cancel out.

See U.S. EPA, Plain English Guide to the Part 75 Rule, June 2009, at Table 6, available at http://www2.epa.gov/sites/production/files/2015-05/documents/plain_english_guide_to_the_part_75_rule.pdf.

As stated above, the PM emissions for the Hunter units in the 1995 and 1996 PacifiCorp emission inventories were based on the 1/95 version EPA's AP-42 emission factors at Table 1.1-5, 1/95, as well as the actual amount of coal burned. Those EPA AP-42 emission factors are based on actual ash content of the coal, the actual coal heating value, the type of coal (i.e., bituminous), the type of boiler (i.e., dry bottom), and the PM controls installed. *See* https://www.epa.gov/sites/default/files/2020-11/documents/ap42_5thed_orig.pdf, for 1/95 version of Table 1.1-5. CEMs for particulate matter did not exist in the 1995-1996 timeframe. Further, sources often did not regularly perform stack tests for PM until Title V permits were issued, which required periodic stack tests. Thus, PacifiCorp's use of AP-42 emission factors for 1995 and 1996 actual PM emissions was typical for estimating actual PM emissions during that timeframe. PacifiCorp also included excess PM emissions in its calculation of annual PM emissions from excess emission reports. *See* Hunter Emissions Inventory 1995 (Ex. 14) and Hunter Emissions Inventory 1996 (Ex. 15).

To sum up, UDAQ's reliance on allowable emissions to reflect pre-project actual emissions before the 1997-1999 Hunter projects was not technically justified because there was reliable evidence (based on PacifiCorp's 1995 and 1996 emission inventories) showing that actual emissions differed significantly and were much lower than the allowable emissions relied on by UDAQ to reflect pre-project actual emissions as shown in Table 10 above. UDAQ itself included in the Hunter Title V permit record the PacifiCorp actual emissions inventories for 1995 and 1996 that demonstrate the unreasonableness of UDAQ's reliance on allowable emissions to reflect pre-project actual emissions at Hunter Units 1, 2, and 3. Thus, EPA should not give any weight to UDAQ's undocumented and unfounded claims that the 1995 and 1996 PacifiCorp actual emission inventories for 1995 and 1996 were based on unreliable data.

B. <u>UDAQ's Claim that If It Would Have Used an Actual Emissions Baseline Then It Should Have Used Projected Actual Emissions to Reflect Post-Project Emissions for the 1997-1999 Hunter Projects is Inconsistent with the Utah SIP in Effect at the Time and Would Still Result in the Hunter Projects Being Subject to PSD Permitting.</u>

In the Appendix to the 2021 Hunter Title V Permit responding to EPA's reopening for cause, UDAQ made the argument that an "actual-to-future actual" emissions applicability test could apply to the 1997-1999 Hunter projects. *See* 2021 Hunter Title V Permit, Appendix at 15-17 (Ex. 1 at pdf pages 79 to 81). Sierra Club's June 2021 comments on the draft 2021 Hunter Title V Permit responded to UDAQ's claim, and explained how the Utah SIP at the time of the Hunter projects did not allow for PSD applicability to be based on an "actual-to-future actual" emissions applicability test. *See* Sierra Club, Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT), June 11, 2021, at 21-24 (Ex. 2). UDAQ responded to Sierra Club's comments that it was not actually purporting to use an actual-to-future actual emissions applicability test for the 1997-1999 Hunter projects. *See* UDAQ, Response to Sierra Club's Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) with Utah's Response to EPA's January 13, 2021 Reopening for Cause (dated June 11, 2021), at 7 (Ex. 7). However, UDAQ claimed that, if they would have used actual emissions instead of allowable emissions to reflect pre-project baseline emissions at the Hunter units, "it would have been improper to apply the potential-to-emit presumption for post-project actual emissions." *Id.* Utah's claims are entirely unjustified.

Sierra Club stated in its June 2021 comments that the plain language of the Utah SIP as in effect at the time of the 1997-1999 Hunter projects did not provide for an actual-to-projected future actual" emissions test and that the Utah SIP was not revised to allow for an actual-to-future actual test for electric utility boilers like the Hunter units until 2004. Sierra Club, Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT), June 11, 2021, at 21 (Ex. 2). *See also* EPA's August 19, 2004 approval of revisions to the Utah SIP incorporating Utah's regulatory revisions to the definitions of "actual emissions" and "representative actual annual emissions" (among other definitional changes) effective at the state level on 7/12/01 (i.e., after completion of the 1997-1999 Hunter projects) at 69 Fed. Reg. 51,638 and 51,639 (Aug. 19, 2004), which became effective 10/18/04. As explained in Section I.A. above, Utah's definition of "actual emissions" in effect at the time of the Hunter projects tracked the federal definition of "actual emissions," which EPA interpreted as requiring an "actual-to-potential" emissions test for PSD applicability for non-routine changes to existing major sources. *See* definition of "actual emissions" in Utah Air Conservation Regulation R307-1-1 (effective 1/1/1995), Ex. 5. While EPA adopted PSD rule revisions in 1992 allowing electric utility steam generating units to use an "actual-to-representative actual" emissions test for PSD applicability, EPA did not mandate that states adopt the 1992 revisions applicability rules for electric utility generating units to retain approval of their PSD permitting regulations as EPA stated clearly in its 2004 approval of the Utah SIP revisions first allowing for an actual-to-future actual PSD applicability test. Specifically, EPA said in that Utah SIP rulemaking "States were not required to adopt revisions to implement these [July 21, 1992 Federal PSD rule changes], although these changes are in effect in areas where the Federal PSD permitting regulations apply." *See* 69 Fed. Reg. 51,638 at 51,639 (Aug. 19, 2004). The areas where the Federal PSD permitting regulations apply are those areas which have not adopted and gained EPA approval of PSD permitting regulations as part of the SIP. In such cases, EPA specifically states in the SIP section for each applicable state in 40 C.F.R. Part 52 that the Federal PSD regulations in 40 C.F.R. 52.21 are incorporated into the implementation plan. As previously discussed, Utah has adopted PSD regulations which EPA has approved as part of the SIP. *See* 40 C.F.R. 52.2346(a).

UDAQ also cited to a Montana Court decision to support its claim that an actual-to-future actual emissions test was required under Utah's SIP, but that Montana Court decision explicitly pertained to the Montana SIP and not the Utah SIP as Sierra Club explained in its June 11, 2021 comments at pages 21-22 (Ex. 2). *See also Sierra Club v PPL Montana LLC*, No. CV 13-32, slip op. at 7 (Aug. 13, 2014).

UDAQ also attempted to justify use of a future actual test for post-project emissions by claiming the Hunter projects were "like-kind replacements." Even if such an approach could be supported by the text of the regulations, UDAQ does not provide an adequate justification for such a finding in the permit record. As discussed by EPA in its proposed June 14, 1991 rulemaking, the Court in *Wisconsin Elec. Power Co. V. Reilly (WEPCO)*, 893 F.2d 901 (7th Circuit 1990), used the term "like-kind replacement" and described the term as one that "does not 'change or alter' the design or nature of the facility" and as one "that merely allows the facility to operate again as it had before the specific equipment deteriorated." 56 Fed. Reg. 27,630 at 27,633 (June 14, 1991), citing *WEPCO*, 893 F.2d at 908. However, the 1997-1999 Hunter projects cannot be considered as "like kind replacements" to justify assuming that normal operations had begun on the units and applying an actual-to-future actual emissions applicability test. Sierra Club's June 11, 2021 comments to UDAQ explained at page 23 that the projects could not be considered like kind because the 1997-1999 Hunter projects would increase the actual capacity of the units and has the potential to increase short term emission rates.

Indeed, PacifiCorp's 1997 Notice of Intent stated that the hourly heat input capacity of the units would increase from 4,160 MMBtu/hr at each unit to 4,700 MMBtu/hr at Units 1 and 2 and from 4,160 to 4,900 MMBtu/hr at Unit 3. PacifiCorp's August 18, 1997 Notice of Intent at pdf pages 9 and 12 (Ex. 9). In addition, generating capacity would increase by 52-65 net MW at each Hunter unit and that future potential annual coal throughput would increase by 8.2% at Hunter Units 1 and 2 and by 12.8% at Unit 3. *Id.* UDAQ included a 1996 Notice of Intent prepared by PacifiCorp that went into more detail about the 1997-1999 Hunter projects in its Response to Sierra Club's June 11, 2021 comments. UDAQ, Response to Sierra Club's Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) with Utah's Response to EPA's January 13, 2021 Reopening for Cause (dated June 11, 2021), Exhibit 1 thereto (Ex. 7). As will be discussed in Section II.D.2. below, that more detailed information provides further support to show that the 1997-1999 Hunter projects should not be considered to be like kind replacements.

Although Sierra Club does not agree that an actual-to-future actual test would apply under the terms of the Utah SIP as in effect at the time for the reasons described above, Sierra Club did provide an analysis of actual emissions before the 1997-1999 Hunter projects and projected actual emissions after the Hunter projects in its June 2021 comments to UDAQ. Sierra Club, Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) with Utah's Response to EPA's January 13, 2021 Reopening for Cause, submitted to UDAQ June 11, 2021 at 27-28 (Ex. 2).

PacifiCorp arguably did provide a projection of post-project emissions in its August 1997 Notice of Intent because it only assumed an operating capacity factor of 95% in projecting post-project emissions rather than a 100% capacity factor. *See* August 18, 1997 PacifiCorp NOI, Request for Approval Order Modifications to Limit the Potential to Emit at the Hunter Plant, Ex. 9 at pdf page 12. PacifiCorp did not request any operational limitations in its permit reflecting a 95% capacity factor, and UDAQ did not impose any such limits. *See* November 20, 1997 Approval Order DAQE-1099-97 (Ex. 10) and December 18, 1997 Approval Order DAQE-1189-97 (Ex. 11). The table below provides Sierra Club's analysis of an actual-to-future actual emissions PSD applicability test for the 1997-1999 Hunter projects based on documentation in the 2021 Hunter Title V permit record.

Table 12. Determination of Whether the 1997-1999 Hunter Projects Should Have Been Projected to Result in a Significant Emission Increase Using an Actual-to-Future Actual Emissions Test[33]

Pre-project Actual NOx (95-96 Avg), tpy	Future Actual NOx, tpy	Increase in NOx, tpy	Pre-project Actual SO_2 (95-96 Avg), tpy	Future Actual SO_2, tpy	Increase in SO_2, tpy	Pre-project Actual PM (95-96 Avg), tpy	Future Actual PM, tpy	Increase in PM, tpy
Hunter Unit 1								
6,993	8,801	**1,808**	2,534	4,107	**1,573**	651	858	**207**
Hunter Unit 2								
6,672	8,801	**2,129**	2,404	4,107	**1,703**	597	858	**261**
Hunter Unit 3								
6,273	9,379	**3,106**	1,206	2,039	**833**	257	408	**151**
Hunter Plant								
19,937	26,981	**7,044**	6,144	10,253	**4,109**	1,505	2,124	**619**

For this table, pre-project actual emissions based on the annual average of 1995-1996 emissions reported for each Hunter unit in PacifiCorp's 1995 and 1996 Emission Inventory reports in Exs. 14 and 15. Future actual emissions are based on PacifiCorp's August 1997 Notice of Intent identification of "Future Potential Emissions" which clearly take into account a 95% capacity factor (listed as "CF" in the Notice of Intent), Ex. 9 at pdf page 15. The above analysis was provided to UDAQ in Sierra Club's June 11, 2021 comments at page 28 (Ex. 2). For the reasons stated in Section I.B.2 above, there were no creditable emission decreases for the 1997-1999 Hunter projects because the emission limits requested and imposed on Hunter Units 1, 2, and 3 did not reduce emissions to be lower than the actual emissions of each Hunter unit. Thus, the analysis in the above table of actual-to-future actual emission increases associated with

[33] Baseline actual emissions based on the annual average of 1995-1996 emissions reported for each Hunter unit in its 1995 and 1996 Emission Inventory reports in UDAQ Attachments 5 and 6. Future actual emissions are based on PacifiCorp's August 1997 NOI at pdf page 15, which identified PacifiCorp's "Future Potential Emissions" (in Ex. 1 to Sierra Club's November 13, 2015 Comments to UDAQ, in UDAQ's Attachment 21).

the 1997-1999 Hunter projects reflects the net emissions increase for SO2 and for NOx. For PM, the net emissions increase will be higher than reflected in the table above because there were contemporaneous and creditable PM emission increases associated with the burning of more coal after the 1997-1999 Hunter projects, as shown in Table 5 above.

In UDAQ's response to Sierra Club's June 11, 2021 comments, UDAQ claims that the 95% capacity factor was justified as reflective of the potential to emit of the Hunter units after the 1997-1999 Hunter projects. Specifically, UDAQ stated:

> UDAQ properly applied its technical judgment in 1997 to determine that coal-fired electric generating units operating under their physical and operational design did not have the capacity to operate continuously for 8,760 consecutive hours at 100 percent of the maximum heat input rate, which is achievable on a short-term basis only. Accordingly, the heat input rates UDAQ used to calculate potential-to-emit represented the actual capacity of the source, which cannot realistically be exceeded. As a result, UDAQ did not need to impose any additional independently-enforceable limitations on annual heat input—the limit was already realistically at 95%. UDAQ also did not need to include any such limits in the approval order.

UDAQ, Response to Sierra Club's Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) with Utah's Response to EPA's January 13, 2021 Reopening for Cause (dated June 11, 2021), at 9 (UDAQ Response to Comment #9), Ex. 7.

UDAQ's justification for considering PacifiCorp's calculations based on 95% capacity factor as reflecting potential to emit of the Hunter units after the 1997-1999 Hunter projects contradicts the plain language of the definition of "potential to emit" in both the Utah SIP in effect at the time and in EPA's PSD regulations. "Potential to emit" is defined as "the maximum capacity of a source to emit a pollutant under its physical and operational design," and the definition also requires that "[a]ny physical or operational limitation on the capacity of the source to emit a pollutant including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation or the effect it would have on emissions is enforceable." *See* definition of "potential to emit" in Utah Air Conservation Regulations R307-1-1 as in effect 1/1/95 (Ex. 5). *See also* 40 C.F.R. 51.166(b)(4); 40 C.F.R. 52.21(b)(4). EPA commonly required potential to emit to be based on maximum capacity of a source operating continually through the year. *See*, e.g., May 16, 1979 Letter from Edward E. Reich, EPA, to Jerry L. Phillips, Burns & McDonnell, available at https://www.epa.gov/sites/default/files/2015-07/documents/respletr.pdf. Thus, the only reasonable interpretation of PacifiCorp's Future Potential Emissions of each Hunter unit after the 1997-1999 projects that took into account a 95% capacity factor is that these post-project emission projections were mean to represent future actual emissions for the units after the 1997-1999 Hunter projects.

For all of the above reasons, UDAQ's claim that if it used an actual emissions baseline, it was required to use an actual-to-projected actual emissions test is legally flawed and, even if it was not a legally flawed proposition, it is of no moment. Based on the documentation in the Hunter Title V permit record, the 1997-1999 Hunter projects should have been considered to be subject to PSD permitting as major modifications for NOx, SO_2, and PM.

C. UDAQ's Justification for Assuming a 95% Capacity Factor that is Not an Enforceable Requirement When Calculating Post-Project Potential to Emit is Legally Flawed.

As discussed in the section above, UDAQ did not evaluate post-change emissions for the 1997-1999 Hunter projects based on the potential to emit as that term is defined in the Utah SIP. Instead of determining post-change emissions based on the Hunter units operating at maximum capacity continually throughout the year, UDAQ relied on PacifiCorp's post-project emission calculations based on 95% capacity factor. UDAQ claims those emissions reflect the "realistic" potential to emit of the Hunter units after the 1997-1999 Hunter projects. UDAQ, Response to

Sierra Club's Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) with Utah's Response to EPA's January 13, 2021 Reopening for Cause (dated June 11, 2021), at 9 (UDAQ Response to Comment #9), Ex. 7. However, given that there was no limitation on the units' capacity factors to limit capacity factor to 95%, there was no legal justification for UDAQ's assumption that post-project potential emissions could be calculated based on 95% of the potential to emit of the Hunter units after the 1997-1999 Hunter projects.

In the PSD applicability analysis that Sierra Club presented in Section I.B. above, Sierra Club presents the true "potential to emit" of the Hunter units after the 1997-1999 projects. The potential to emit calculated by Sierra Club was based on the post-project hourly heat input capacity of each boiler (in MMBtu/hr), the NOx, SO2, and PM emission limits incorporated into the 1997 Approval Orders, and assuming continual operation (i.e., 8,760 hours) throughout the year. Table 4 above has Sierra Club's calculated post-change potential to emit. The table below reprints the post-change potential to emit emissions for each Hunter unit and compares to the post-project 95% capacity factor potential emissions assumed by UDAQ.

Table 12. Comparison of Post-Project Potential to Emit for Hunter Units 1, 2, and 3 Compared to UDAQ's Assumed Post-Project Potential Emissions (Which Take Into Account a 95% Capacity Factor that has Not Been Made Into an Enforceable Requirement).

Pollutant		Hunter Unit 1	Hunter Unit 2	Hunter Unit 3	Hunter Plant
NOx	Potential to emit, tons/year	9,264	9,264	9,873	28,400
	UDAQ's Potential at 95% Capacity Factor, tons/year	8,801	8,801	9,379	**26,981**
	Amount by which UDAQ Understated Post-Project Potential to Emit, tpy	**463**	**463**	**494**	**1,419**
SO2	Potential to emit, tons/year	4,323	4,323	2,146	10,792
	UDAQ's Potential at 95% Capacity Factor, tons/year	4,107	4,107	2,039	10,253
	Amount by which UDAQ Understated Post-Project Potential to Emit, tpy	**216**	**216**	**107**	**539**
PM	Potential to emit, tons/year	1,029	1,029	429	2,488
	UDAQ's Potential at 95% Capacity Factor, tons/year	858	858	408	2,124
	Amount by which UDAQ Understated Post-Project Potential to Emit, tpy	**171**	**171**	**21**	**354**

Data for this table is from PacifiCorp's August 18, 1997 Notice of Intent, Ex. 9 at pdf 12.

As demonstrated in the above table, UDAQ's decision to take into a 95% capacity factor in its evaluation of post-project potential to emit greatly understated post-project potential to emit from the Hunter units, most dramatically for NOx emissions. UDAQ's justification to apply a 95% capacity factor to post-project potential to emit without a corresponding enforceable restriction on capacity factor was entirely inconsistent with the definition of "potential to emit" under the Utah SIP and Federal PSD regulations.

D. <u>UDAQ's Claims that PSD Should Not Apply to the 1997-1999 Hunter Projects and/or that BACT Should Not Apply to the Hunter Boilers Because the Projects that Caused the Emission Increases Were Not Physical Changes to the Boilers is Wholly Unjustified and Baseless.</u>

UDAQ has claimed that the projects that Sierra Club alleges are major modifications are only pertaining to the changes to the steam turbines. UDAQ claims that the boiler projects listed in PacifiCorp's August 18, 1997 Notice of Intent were to return Unit 3 to "as permitted" status due to design and construction flaws, or have no effect on boiler capacity or emissions, or were pollution control projects. 2021 Hunter Title V Permit, Appendix at 5 (Ex. 1 at pdf page 69). UDAQ claimed the changes to the steam turbines are separate and distinct from emissions or capacity increases at the boilers and thus "do not require that the boilers be evaluated under PSD…." *Id.* UDAQ's claim that PSD would not apply to the 1997-1999 Hunter projects, even if it were true that it was only the steam turbine projects that would result in an increase in emissions, directly conflicts with the definition of "major modification," which is defined under Utah's SIP and Federal PSD regulations as "any physical change or change in the method of operation of a major stationary source…that would result in a significant emission increase…and a significant net emissions increase of that pollutant from the major stationary source."[34] In the case of the Hunter plant, the major stationary source is a "fossil fuel-fired steam electric plant of more than 250 million British Thermal Units per hour heat input." *See* definitions of "major modification" and "major source for the purpose of Subsection R307-1-3.6" in Utah Air Conservation Regulations R307-1-1 (effective 1/1/1995), Ex. 5. *See also* 40 C.F.R. 51.166(b)(1) and (2); 40 C.F.R. 52.21(b)(1) and (2). Thus, the steam turbines are part of the "major source" and even if the only changes that allowed for an emission increase at the Hunter units were due

[34] Note that UDAQ cited to *In Re Rochester Pub. Utils.*, 11 E.A.D. 593 (EAB 2004), to support its claim that if the physical changes allowing for an emissions increase are due only to turbine changes, then BACT would not apply to the boiler. However, the *Rochester* EAB decision did not address the issue of whether there was an operational change to the boiler associated with turbine upgrades, because the Petitioner only argued that there was a physical change. *In Re Rochester Pub. Utils.*, 11 E.A.D. 593 at 603 (EAB 2004) ("Petitioner further curtailed its arguments by only maintaining that there was a physical modification…and makes no argument as to whether there would be a change in the method of operation (i.e., "operational modification") at the facility due to the project…Accordingly, we decide this matter based on the narrow issue Petitioner actually presented in the Petition for Review, without addressing any other possible issues associated with the issuance of PSD permits without BACT limits.")

to changes at the steam turbines (which is not the case here, as will be discussed below), a PSD applicability analysis would be required.[35]

UDAQ also claimed that Sierra Club "mistakenly did not separate 'turbine' projects from other boiler related projects when analyzing the need for BACT, and that it is improper to combine the boiler and non-boiler projects together to justify a boiler-specific BACT requirement." 2021 Hunter Title V Permit, Appendix at 6 (Ex. 1 at pdf page 70). Regardless, however, of whether a major modification triggers a determination of BACT for an emissions unit at a source, the PSD permitting requirements include additional requirements aside from BACT that may result in emission limitations being imposed on a source or an emissions unit, including the requirement to ensure the modified source complies with the National Ambient Air Quality Standards (NAAQS) and the PSD increments and that the modified source won't adversely impact visibility or other air quality related values at Class I areas, among other requirements.

The rule regarding BACT to which UDAQ presumably refers is the Federal PSD provision that states: "[a] major modification shall apply best available control technology for each regulated NSR pollutant for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit." *See* 40 C.F.R. 52.21(j)(3). The term "emissions unit" is defined in the Federal PSD regulations as "any part of a stationary source that emits or would have the potential to emit any regulated [new source review] pollutant and includes an electric utility steam

[35] EPA's May 23, 2000 letter to Henry Nickel regarding the "proposed replacement and reconfiguration of the high pressure section of two steam turbines" at the Detroit Edison Monroe Power Plant provides one example of EPA finding that turbine modifications at existing coal-fired power plants do require a PSD evaluation. This EPA applicability analysis is available at https://www.epa.gov/sites/default/files/2015-07/documents/detedisn.pdf.

generating unit as defined in [40 C.F.R. 52.21(b)(31]….” 40 C.F.R. 52.21(b)(7). And the Federal PSD regulations define "electric utility steam generating unit" as "any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility." 40 C.F.R. 52.21(b)(33). Under these definitions, the steam turbine is part of the emissions unit. These definitions were not in the Utah SIP in effect at the time of the 1997-1999 Hunter projects,[36] but the BACT applicability provision of 40 C.F.R. 52.21(j)(3) -- that BACT only be applied to each emission unit at which a net emissions in the pollutant would occur as a result of the physical or operational change was also not in the Utah SIP in effect at the time of the 1997-1999 Hunter projects. *See* Section 3.1.8.A. (regarding the requirement for BACT to be met) of Utah Air Conservation Rule R307-1-3, effective 1/1/1995, Ex. 5. However, if EPA grants this petition and orders UDAQ to issue a PSD permit for the 1997-1999 Hunter projects, the BACT determination and other requirements of that permit would be governed by the current Utah PSD permitting regulations approved by EPA as part of the SIP. The current Utah PSD regulations have incorporated by reference the relevant definitions cited above and have incorporated the BACT applicability provision of 40 C.F.R. 52.21(j)(3). *See* Utah Air Conservation Regulation R307-405-3(1) which incorporates by reference the definitions of 40 C.F.R. 52.21(b) with some limited exceptions that do not pertain to this issue. *See also* Utah Air Conservation Regulation R307-405-11 which incorporates by reference the provisions of 40 C.F.R. 52.21(j). The SIP-

[36] In fact, the Utah SIP in effect at the time of the 1997-1999 Hunter projects did not include a definition for "emissions unit"(or any similar term) at all.

approved versions of these rules are , available at https://www.epa.gov/system/files/documents/2021-09/table-c-ut.pdf#R307-405.

Moreover, the facts regarding the 1997-1999 Hunter projects that have been made available as part of the 2021 Hunter Title V permit and UDAQ's response to comments indicate that there were both changes at the steam turbine and at the boiler that are related to the significant emission increases that should have been project to occur based on a proper PSD applicability analysis under the terms of the Utah SIP as in effect at the time and that actual did occur in at least one of the five years after completion of the projects. This is explained below.

First, in its August 18, 1997 Notice of Intent upon which the 1997 Approval Orders are based,[37] PacifiCorp tied these projects together in its August 1997 Notice of Intent by stating, among other things, that while some of the projects by themselves could not cause an increase in emissions, "as a whole, the upgrades may increase the actual capacity and capacity utilization of the boilers." August 18, 1997 PacifiCorp Request for Approval Order Modifications at 1 [emphasis added] (Ex. 9). PacifiCorp's August 1997 Notice of Intent also clearly indicated that hourly heat input capacity of the boilers was expected to increase from 4,160 MMBtu/hr at each unit to 4,700 MMBtu/hr at Hunter Units 1 and 2 and to 4,900 MMBtu/hr at Hunter Unit 3, as shown in Table 2 above. Further, PacifiCorp's August 1997 Notice of Intent clearly indicated that annual coal throughput at the Hunter plant would increase, both by projecting higher annual coal consumption and higher generating capacity at each unit using a baseline of 100% capacity factor at 400 megawatts (MW) net at each unit and a post-project assumption of a 95% capacity factor at 452 MW net at Units 1 and 2 and 465 MW net at Unit 3. *Id.* at pdf pages 9 and 12. This

[37] UDAQ's New/Modified Source Plan Review specifically refers to the Notice of Intent from August 20, 1997 (which is included in UDAQ's December 18, 1997 Approval Order DAQE-1189-97 at pdf page 9 (Ex. 11)). As previously stated, a "Notice of Intent" under Utah permitting rules is an application for a permit to construct. See R307-1-3.1.1 (Effective 1/1/1995), Ex. 5.

shows both that generating capacity would increase by 52-65 net MW at each Hunter unit and that future potential annual coal throughput would increase by 8.2% at Hunter Units 1 and 2 and by 12.8% at Unit 3. Sierra Club raised these comments to UDAQ in its June 11, 2021 comment letter at pages 7-8 (Ex. 2).

Second, in its response to Sierra Club's June 11, 2021 comments, UDAQ attached an additional PacifiCorp document that provides more detail on the 1997-1999 Hunter projects and that confirms that there were both physical and operational changes to the boilers that were necessary for successful operation of the steam turbine projects. Thus, it would not be appropriate to separate the turbine projects from the boiler projects in determining applicability of BACT. That additional document is Exhibit 1 to UDAQ, Response to Sierra Club's Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) (Ex. 7 at pdf pages 15 to 35). The new exhibit is a document labeled "Notice of Intent, Physical Changes at the PacifiCorp Hunter Power Plant," prepared by PacifiCorp, dated August 1996 (hereinafter referred to as "1996 Notice of Intent"). This document was not included in the draft 2021 Hunter Title V Appendix (which had 33 Attachments that UDAQ included to support its 2021 Hunter Title V Permit Appendix responding to EPA's reopening for cause). Furthermore, the document was not otherwise made available for public review as part of the 2021 Hunter Title V permit responding to EPA's reopening for cause. This 1996 Notice of Intent is also not cited in PacifiCorp's August 18, 1997 Notice of Intent (Ex. 9) or in UDAQ's 1997 Approval Orders or its New/Modified Source Plan Review for the 1997-1999 Hunter projects (Exs. 10 and 11). As a result, Sierra Club had never reviewed the 1996 document and never had a chance to comment on it until it was made available in UDAQ's Response to Comments in October 2021. The 1996 Notice of Intent has much more detail on the physical and operational changes of the 1997-1999 Hunter projects at issue in this petition, and Sierra Club finds it provides support for its claim that there were physical and/or operational changes to the Hunter boilers associated with the 1997-1999 Hunter projects that were related to the projected heat input (and thus emission) increases and that were also related to the actual emission increases that occurred shown in Table 7 above. It was impracticable for Sierra Club to raise these issues during the public comment period on the 2021 draft Hunter Title V Permit for the reasons stated above (that it was not made available as part of the 2021 Hunter Title V Permit action and indeed Sierra Club has not seen this document until it was attached as Exhibit 1 to UDAQ's Responses to Sierra Club's comments that it issued in October of 2021).

As stated in PacifiCorp's August 1997 Notice of Intent, the 1997-1999 Hunter projects included (among other things) "turbine changes including aeroderivative design" at Hunter Unit 3 and "turbine changes including ruggedized rotor design" at Hunter Units 1 and 2. August 18, 1997 Notice of Intent at pdf page 3 (Table 1), Ex. 9. The 1996 Notice of Intent provides more detail on these projects. The August 1997 Notice of Intent also identified several boiler projects at each Hunter unit. In Section II.D.2. below (and in the attached report of Joseph Van Gieson, Ex. 23), Sierra Club explains how some of the boiler projects are related to and necessitated by the turbine projects.

1. *The Hunter Units 1 and 2 Projects Included Physical and Operational Changes at the Boilers that Were Related to the Turbine Projects and Projected Heat Input Increases.*

The 1996 Notice of Intent describes the "turbine changes including ruggedized rotor design" at Hunter Units 1 and 2 as follows:

> The low pressure section of the turbine will be modified to Westinghouse current "ruggedized" rotor design. The stress loading on the last stage blades of the existing rotor design are currently the highest in industry practice for this model

> and configuration. Other rows in these rotors have also experienced failures and reduced reliability. In order to utilize the existing steaming capacity from the boiler, the high pressure and intermediate pressure sections of the turbines will be modified to allow passage of 3,318,000 pph at 2535 psia and 1000 °F steam available from the boiler.

See 1996 Notice of Intent at Section A.2.(f) (Ex.7 at pdf page 22).

PacifiCorp admitted in Section A.2.(c) of the 1996 Notice of Intent that, at Hunter Units 1 and 2 "[t]he superheat steam temperatures are about 25-50 °F short of the 1005 °F design temperature when the burner tilts are operated in the horizontal condition." (Ex. 7 at pdf page 21). Specifically, the 1996 Notice of intent states:

> The boiler has a design deficiency in the superheater surface which manifests itself at higher operating loads. The superheat steam temperatures are about 25-50 °F short of the 1005 °F design temperature when the burner tilts are operated in the horizontal condition. Desired steam temperatures can be attained if the tilts are raised to plus 25 degrees. However, NOx control capability is reduced and deleterious ash deposits accumulate more readily in the convection passes when operating the tilts in this position. The faster accumulation of deposits in the narrowly spaced tube panels cause pluggage, increased erosion wear, and an overall reduction in reliability.

See 1996 Notice of Intent at Section A.2.(c) (Ex.7 at pdf page 21).

The 1996 Notice of Intent discusses an option to address this design deficiency, and that is through the addition of superheater surface area. See 1996 Notice of Intent at Section A.2.(c) (Ex.7 at pdf page 21). An increase in superheater surface area would enable an increase in steam temperature to the turbine design temperature of 1000 ° Fahrenheit. *See* Ex. 23, Report of Joseph Van Gieson, at 14. However, UDAQ has indicated that the addition of superheater surface area was never completed at Units 1 and 2. *See* 2021 Hunter Title V Permit, Appendix at 5 (Ex. 1 at pdf page 69).

Without the addition of superheat surface area to the Unit 1 and 2 boiler to address the mismatch between the superheat steam temperature and the design steam temperature of the high pressure turbine, it must be concluded that operation of the burner tilts in the Units 1 and 2 boilers at plus 25 degrees was necessary to operate at design steam temperatures. *See* Ex. 23, Report of Joseph Van Gieson, at 14. As stated in the attached report from Mr. Van Gieson, PacifiCorp would not have undertaken the turbine modifications unless the superheater of the boiler would be able to deliver steam at 1000 °F, because to do so would have meant a significant investment in turbine upgrades without achieving the benefit of increased production capacity. *See* Ex. 23, Report of Joseph Van Gieson, at 15. Operation of the burner tilts in the Units 1 and 2 boilers at plus 25 degrees is an operational change to the boiler. And PacifiCorp acknowledged in the 1996 Notice of Intent that, with the operation of the burner tilts at plus 25 degrees, "NOx control capability is reduced," indicating that this operational change at the boilers could increase emissions. Indeed, despite the NOx control projects installed at Units 1 and 2 as part of the 1997-1999 Hunter projects, NOx emission rates in terms of lb/MMBtu did not consistently decrease or decrease appreciably, and both Units 1 and 2 had significant annual increases in NOx emissions for at least one year in the five years post-project. *See* Ex. 23, Report of Joseph Van Gieson, at 14-15.

The 1996 Notice of Intent also discusses proposed replacement of the air preheater elements:

> The air preheater elements will be replaced, because the elements are worn and breakage is occurring. The elements also experience pluggage from fly ash. This pluggage causes unit output restrictions and causes the induced draft fans to operate at maximum output. Under normal conditions, the pressure drop induced by the pluggage and breakage of the heat transfer material in the air preheater is not the load limiting factor. To provide added conservatism to the design, an induced draft fan rotor with a larger wheel diameter will be retrofit to increase pressure drop margins across the air preheater.

See 1996 Notice of Intent at Section A.2.(a) (Ex.7 at pdf page 21).

According to Mr. Van Gieson's report, the replacement of the air preheater elements would "reduce or eliminate the effect of flyash pluggage" from reducing Unit 1 and 2's load (i.e., reducing the units' generating capacity) and the larger rotor wheel diameter in the induced draft fan could increase the pressure drop margins across the air preheater (which would also reduce derates due to flyash pluggage in the air preheater). *See* Ex. 23, Report of Joseph Van Gieson, at 14. The description of the replacement of the "air preheater elements" in the 1996 Notice of Intent would allow for more consistent operation of Units 1 and 2 at higher loads. *Id.* These changes would allow the boiler to produce the steam flow, temperature, and pressure matching the upgraded high pressure and intermediate pressure turbines (i.e., 3,318,000 pounds per hour of steam at 2535 psia and 1000 °F).

Thus, as demonstrated in the 1996 Notice of Intent and as explained in Mr. Van Gieson's report, there were both physical and operational changes to the Hunter Units 1 and 2 boilers that were related to the changes to the units' steam turbines. Thus, UDAQ's arguments that BACT would not be required at the Units 1 and 2 boilers because only the turbines allowed for the projected increases in heat input at the boilers are not supported in the Hunter Title V permit record.

2. *The Hunter Unit 3 Projects Included Physical and Operational Changes at the Boiler that Were Related to the Turbine Project and Projected Heat Input Increase*

PacifiCorp stated the following about the Unit 3 changes in its August 1997 Notice of Intent:

> On March 21, 1995, PacifiCorp notified the Utah Division of Air Quality (DAQ) that a settlement had been reached in litigation with the manufacturer of the Hunter Unit 3 boiler. The basis for the litigation was design deficiencies in the boiler as constructed. The letter contained a brief description of the proposed upgrade which consists of physical changes to the Unit 3 boiler which were

> planned to correct these deficiencies in connection with the settlement. At that time, PacifiCorp concluded on the basis of information then available that the anticipated physical changes would not cause an increase in emissions and therefore would not trigger additional permit requirements. Some of those changes have already been accomplished and the rest are underway <u>as part of the overall boiler upgrade</u>. The remaining proposed changes for Unit 3 as well as changes that are being proposed for Units 1 and 2 have been further analyzed. It is apparent that some of the remaining proposed changes could cause an increase in annual emissions.

PacifiCorp August 18, 1997 PacifiCorp Notice of Intent at 1 (emphasis added), Ex. 9. PacifiCorp's statements make clear these physical changes go beyond addressing any claimed design defects and that they are instead part of an "overall boiler upgrade" (especially given that the hourly heat input capacity and electrical generating capacity would increase significantly). Indeed, the 1996 Notice of Intent that UDAQ has included with its response to Sierra Club's June 11, 2021 comments on the draft Hunter Title V Permit Appendix show that the Unit 3 upgrades include a change in design of the unit.

The 1996 Notice of Intent describes turbine changes at Hunter Unit 3 as follows:

> The steam turbine will be modified to allow passage of 3,341,000 [pounds per hour (pph)] when operating at the steam inlet conditions of 2520 [pounds per square inch gauge] and 1000 °F. The high pressure and intermediate pressure sections will be retrofit with advanced, aerodynamic design buckets…This physical change will allow PacifiCorp to utilize more of the steam generator's capability for power generation.

See 1996 Notice of Intent at Section A.1.(h) (Ex.7 at pdf page 20).

PacifiCorp stated in the 1996 Notice of Intent that the Hunter Unit 3 turbine was originally designed for a maximum steam flow rate of 3,041,000 pounds of steam per hour. *Id.* at Section A.1.(a) (Ex. 7 at pdf page 20). According to the 1996 Notice of Intent, in June 1993 offer to settle a lawsuit filed by PacifiCorp, the Unit 3 boiler manufacturer (Babcock & Wilcox) proposed to "review and change the design of the unit" and proposed changes that "will provide for the utilization of 303,000 pounds per hour of auxiliary steam as additional output to the steam turbine." *Id*. at Section A.1. (Ex. 7 at pdf page 18). The 1996 Notice of Intent also identified several proposed "physical or operational changes associated with Hunter Unit 3" of which one operational change to the boiler and three physical changes to the boiler, in addition to the turbine upgrade, "were all related to a planned increase in steam flow rate from the boiler to the turbine." *See* Ex. 23, Report of Joseph Van Gieson, at 18.

The 1996 Notice of Intent describes a change in method of operation of the Unit 3 boiler that would allow an increase in 303,000 pounds per hour of additional steam flow from the boiler to the upgraded turbine:

> Boiler drum capacity will remain the same at 3,344,000 pph steam flow. The original design flow of steam to the steam turbine was 3,041,000 pph. An additional 203,000 pph of auxiliary steam from an intermediate superheater and 100,000 pph of saturated steam from the steam drum will no longer be extracted and will be allowed to flow to the steam turbine for power generation. **This operational change will increase actual emissions from the steam generator, because an increase in the heat input (mmBtu/hr) will be required to raise the additional 303,000 pph of steam to turbine operating conditions.**

1996 Notice of Intent at Section A.1.(a) (Ex. 7 at pdf page 19) [emphasis added]. Thus, PacifiCorp admits that this operational change at the Unit 3 boiler -- to provide for more steam for the turbine instead of being used for auxiliary steam -- would increase actual emissions. As explained by Mr. Van Gieson, "An increase in heat input to the steam generator to raise temperature of the additional steam flow derived from the intermediate superheater and steam drum to the turbine operating conditions was necessary because the temperatures of the 203,000 pounds per hour of auxiliary steam from the intermediate superheater and the 100,000 pounds per hour of saturated steam from the steam drum were lower than the 1000°F specified for the steam the boiler was to deliver to the high pressure (HP) turbine inlet." *See* Ex. 23, Report of Joseph Van Gieson, at 19. Thus, this operational change to the boiler (to take auxiliary steam and direct it to the modified high pressure steam turbine) was a change directly related to the proposed Unit 3 turbine changes discussed above and it was a change that would increase emissions due to the required increase in heat input. Indeed, the turbine projects and the operational changes to the boiler to no longer take a portion of the steam for auxiliary steam purposes were intertwined because, not only could the Unit 3 boiler not provide the design steam flow to the modified turbine without the operational changes and increased heat input, but also upgrading the turbine to accommodate 3,341,000 pounds per hour of steam flow if the boiler only delivered a steam flow to the turbine of 3,041,000 pounds per hour "would not be practical or justified based on cost effectiveness." *See* Ex. -23 Report of Joseph Van Gieson, at 20.

In addition to the operational change at the Unit 3 boiler to provide the required steam flow for the upgraded turbine, there were physical changes to the boiler that were also related to the upgraded turbine and the higher design steam flow to the turbine. Those included the addition of riser and supply tubes, the replacement of the superheater outlet bank and manifolds, and the resizing of the cold reheat safety valves. With respect to the additional riser and supply tubes, the 1996 Notice of Intent states "[n]o fewer than six riser and supply tubes will be added to ensure adequate circulation flow for the guaranteed operating condition." 1996 Notice of Intent at Section A.1.(b) (Ex. 7 at pdf page 19). The additional risers and supply tubes were expected by PacifiCorp to ensure operation at guaranteed operating conditions by addressing water wall circulation deficiencies and address Hunter Unit 3's inability to operate at maximum continuous rating from June 1986 through May 1995. *Id.* at 18-19. *See also* Ex. 23, Report of Joseph Van Gieson, at 21-22. While PacifiCorp discussed these additions as necessary to correct suspected waterwall circulation flow deficiencies that was the basis for a lawsuit PacifiCorp filed against Babcock & Wilcox, the addition of riser and supply tubes "contributed to the ability of the unit to operate with the increase of 303,000 pounds per hour steam flow from the boiler to the upgraded high pressure turbine at the design conditions of 3,341,000 pounds per hour, at a temperature of 1000 °F and at a pressure of 2,520 pounds per square inch gauge." *See* Ex. 23, Report of Joseph Van Gieson, at 22. Thus, this physical change to the boiler to add risers and supply tubes was also related to the turbine projects at Hunter Unit 3.

PacifiCorp described the superheater outlet bank and manifold replacement at the Hunter Unit 3 boiler as follows:

> The superheater outlet bank, its inlet manifold, and its outlet header will be upgraded to Croloy 9V material. This physical change is necessary for two reasons. First, recent changes in the ASME code have reduced the allowable stresses for the outlet header. Second, use of Croloy 9V material allows for a thinner walled superheater design. The thinner walled tubing will reduce the pressure drop through the superheater. This will allow the use of the original design operating pressure for the steam drum at full load operation….

1996 Notice of Intent at Section A.1.(c) (Ex. 7 at pdf page 19) [emphasis added]. Mr. Van Gieson explains that the superheater outlet bank and manifold replacement and upgrade was related to the increased steam flow from the boiler to the turbine and the related turbine upgrade projects:

> Pressure drop loss in the superheater would be a concern with an increase in steam flow to the turbine of 303,000 pounds per hour because that steam flow increase would also be directed through the superheater outlet which had not previously received that flow. An increase in flow through the existing superheater would result in an increase in steam pressure drop, which would lower the steam pressure at the turbine inlet, because of the associated increase in steam velocity within the existing superheater outlet tubes whose diameter would remain constant unless they were replaced with larger diameter tubes, such as the with the proposed replacement Croloy 9V tubes.

See Ex. 23, Report of Joseph Van Gieson, at 22-23.

Based on information provided in the 1996 Notice of Intent, PacifiCorp admitted having problems operating the Unit 3 boiler at steam pressures greater than 2,400 pounds per square inch gauge. 1996 Notice of Intent at Section A.1. (Ex. 7 at pdf page 18). Yet, the upgraded turbines were stated to be designed for steam inlet conditions of 2,520 pounds per square inch gauge. *Id*. at A.1.(h) (Ex. 7 at pdf page 20). Thus, Mr. Van Gieson found that the change in the superheater outlet tubes was necessary to allow the Unit 3 boiler to deliver steam to the upgraded Unit 3 turbines at the design steam pressure and flow for the upgraded turbine. *See* Ex. 23, Report of Joseph Van Gieson, at 23. Thus, this physical change to the boiler to replace the superheater outlet bank and manifold with Croloy 9V material, which would be thinner-walled and thus larger diameter tubes, was also related to the turbine projects at Hunter Unit 3.

PacifiCorp provided very little justification for the resizing of the cold reheat safety valves at the Hunter Unit 3 boiler, stating only: "The cold reheat safety valves will be resized to meet the ASME code requirements." 1996 Notice of Intent at Section A.1.(g) (Ex. 7 at pdf page 20). Mr. Van Gieson explains that the 10 percent increase in steam flow of the upgraded Unit 3 turbine (i.e., because the Unit 3 turbine was originally designed for a maximum steam flow rate of 3,041,000 pounds of steam per hour and, with the upgraded turbines, would be designed for 3,341,000 pounds of steam per hour – i.e., a 10% increase) would "at least require a review of conformance of the existing relief valves with the ASME boiler code." Ex. 23, Report of Joseph Van Gieson, at 23. Mr. Van Gieson also stated that it was unlikely the existing cold reheat safety valves would be needing replacement due to end of life, being only thirteen years old. *Id*. Mr. Van Gieson also explained how important proper sizing of the cold reheat safety valves is to safe and reliable operation of the boiler:

> Safety relief valves are employed in the steam drum, and steam pipes that transport steam from the boiler to the turbines, and, in the case of cold reheat steam, from the high pressure turbine discharge to the reheater. The relief valves are designed to very quickly release steam in order to reduce steam pressure when emergency conditions, such as steam valve control failures, block steam flow. Such blockages can instantaneously raise steam to pressures to levels that would cause catastrophic failure of steam pipes, boiler tubes or headers, or turbine rotors and shells. A primary purpose of these valves is to protect worker safety. The

> sudden uncontrolled release of feedwater or superheated steam from ruptured steam vessels can cause injury or death. Such failures can also result in extensive unit shutdowns lasting at least several months, and repair and replacement costs would be prohibitive. The ASME boiler code for safety relief valves provides very detailed specifications for the steam flow release capacity of the valves. Changes in the design or maximum continuous rating steam flow rates can require changes to the release capacities of relief valves to comply with ASME boiler code.

Ex. 23, Report of Joseph Van Gieson, at 23.

For these reasons, Mr. Van Gieson finds that the replacement of the cold reheat safety valves at the Unit 3 boiler "was necessary to accommodate the 303,000 pounds per hour increase in steam flow to the high pressure turbine in compliance with the ASME boiler code. Without changing the safety relief valves, Hunter Unit 3 would not have been able to operate at the new upgraded high pressure turbine at the new steam flow rate of 3,341,000 pounds per hour." *Id.* at 24. Thus, the resizing of the cold reheat safety valves is also a physical change to the Unit 3 boiler that is related to the turbine projects at Hunter Unit 3.

In summary, as demonstrated in the 1996 Notice of Intent and as explained in Mr. Van Gieson's report, there were both physical and operational changes to the Hunter Unit 3 boiler that were related to the changes to the unit's steam turbine. Accordingly, UDAQ's arguments that BACT would not be required at the Unit 3 boiler because only the turbine changes allowed for the projected increases in heat input at the boiler are not supported in the Hunter Title V permit record and are unjustified.

III. THE 2021 HUNTER TITLE V PERMIT IS DEFICIENT BECAUSE IT FAILS TO INCLUDE THE APPLICABLE REQUIREMENTS OF THE PSD PERMITTING REGULATIONS IN THE UTAH SIP FOR THE 1997-1999 HUNTER PROJECTS

As demonstrated above, major modifications made at the Hunter Power Plant in the 1997-1999 timeframe should have been subject to PSD permitting requirements. Those requirements include emission limits reflective of best available control technology (BACT) at

Hunter Units 1, 2, and 3 for NOx, SO_2, and PM. In addition, as part of the permit process, PacifiCorp would need to demonstrate that the facility would not cause or contribute to a violation of any national ambient air quality standard (NAAQS) or PSD increment, or adversely impact air quality related values (including visibility) of any Class I area.[38] As part of these analyses, additional emission limits may need to be imposed, including on short term emission rates to provide the short term ambient air standards such as the 1-hour SO_2 and NO_2 NAAQS,[39] the 3-hour average and 24-hour average SO2 increments (Class I and Class II), and visibility.

The emission limits in the 2021 Hunter Title V permit do not reflect BACT for NOx, SO2, or PM at Hunter Units 1, 2, or 3. Sierra Club's November 13, 2015 Comments to UDAQ provides support for the proposition that BACT would require: 1) a NOx emission limit based on operation of selective catalytic reduction (SCR) for NOx at Hunter Units 1, 2, and 3, *see* Sierra Club's November 13, 2015 Comments to UDAQ at 83-87, Ex. 4; 2) an SO2 emission limit based on at least 95% control of SO2 at Hunter Units 1, 2, and 3, *id.* at 87-91; and 3) a PM emission limit of 0.010 lb/MMBtu and a 10% opacity limit at Hunter Units 1, 2, and 3. *Id.* at 91-93. Accordingly, the emission limits and control requirements of the current Hunter Title V permit do not reflect BACT and are less stringent than BACT emission limits.

Since the time of the November 13, 2015 comments to UDAQ, EPA has issued a best available retrofit technology (BART) federal implementation plan (FIP) for Hunter Units 1 and 2 that found that installation of SCR was cost effective for the units and that the units should be able to meet a NOx emission limit of 0.07 lb/MMBtu with SCR and the existing low NOx

[38] Utah Air Conservation Regulation R307-405-11, R307-405-12, R307-405-16, and R307-405-17. The SIP-approved versions of these rules are available at https://www.epa.gov/system/files/documents/2021-09/table-c-ut.pdf#R307-405.

[39] As discussed in Section V of Sierra Club's November 13, 2015 Comments to UDAQ, modeling of the Hunter plant's allowable SO2 emissions has shown a problem complying with the 1-hour SO2 NAAQS. Ex. 4.

burners and overfire air. *See* 81 Fed. Reg. 43,894 – 43,925 (July 5, 2016). In that rulemaking, EPA found that SCR at Hunter Units 1 and 2 was cost effective. 81 Fed. Reg. 43,894 at 43,093-906 (July 5, 2016). Thus, at the minimum, BACT for NOx should be no less stringent (and likely more stringent) than EPA's July 2016 BART FIP NOx limits.

In October of 2020, Sierra Club and other conservation organizations submitted comments to UDAQ on the four-factor reasonable progress controls analysis for Hunter Units 1, 2, and 3 and other facilities under the regional haze program. In its June 11, 2021 comments to UDAQ, Sierra Club submitted a report that showed SCR at Hunter Units 1, 2, and 3 could meet an annual average NOx emission rate of 0.04 lb/MMBtu on a cost-effective basis. Attachment E to Sierra Club, Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) with Utah's Response to EPA's January 13, 2021 Reopening for Cause, submitted to UDAQ June 11, 2021 (Ex. 2). This provides further support that the NOx emission limits and control requirements of the 2020 Hunter Title V permit do not reflect BACT for NOx.

In the Appendix to the 2021 Hunter Title V permit, UDAQ stated that Sierra Club's BACT comments were not supported because Sierra Club did not present an analysis of whether the "BACT applicability" criteria were met. 2021 Hunter Title V Permit Appendix at 6 (Ex. 1 at pdf page 70). Yet, Sierra Club did provide an analysis based on the documentation available in the Hunter Title V permit record at the time showing BACT would be required in its June 11, 2021 comment letter at pages 39-41 (Ex. 2). In Exhibit 1 of UDAQ's response to comments, UDAQ included in the permit record a 1996 PacifiCorp Notice of Intent which provides further support that the 1997-1999 Hunter projects should have triggered applicability of BACT to the boilers at each Hunter unit, as discussed in Section II.D. above. UDAQ, Response to Sierra

Club's Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) with Utah's Response to EPA's January 13, 2021 Reopening for Cause (dated June 11, 2021) at Exhibit 1 (Ex. 7). *See also* Ex. 23, Report of Joseph Van Gieson.

CONCLUSION

For the reasons set forth above, pursuant to Clean Air Act §505(b)(2) and 40 C.F.R. §70.8(d), the Administrator should grant Sierra Club's Petition to object to the 2021 Hunter Title V Operating Permit proposed for issuance by the Utah Division of Air Quality ("UDAQ") for PacifiCorp's Hunter Power Plant on October 2, 2021 and issued as final on November 19, 2021, UDAQ, Revised Title V Operating Permit for PacifiCorp's Hunter Power Plant, Permit No. 1500101004, revised November 19, 2021, Ex. 1.

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Sincerely,

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LIST OF EXHIBITS

Exhibit Number	Title/Description	Where in 2021 Hunter Title V Permit Record
1	UDAQ, Revised Title V Operating Permit for PacifiCorp's Hunter Power Plant, Permit No. 1500101004, issued 11/19/2021	
2	Sierra Club, Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) with Utah's Response to EPA's January 13, 2021 Reopening for Cause, submitted to UDAQ June 11, 2021	
3	EPA, Order Denying Petitions for Objection to Permits and Reopening Permit for Cause, issued 1/13/2021	Attachment 1 to Appendix of 2021 Hunter Power Plant Permit No. 1500101004
4	Sierra Club, Comments on the PacifiCorp-Hunter Power Plant DRAFT Title V Renewal Permit (Permit Number 1500101002-Draft), submitted to UDAQ on November 13, 2015	Attachment 21 to Appendix of 2021 Hunter Power Plant Permit No. 1500101004
5	1995 version of the Utah rules in effect on 1/1/95 from the Utah Department of Administrative Services	Ex. 5 to Attachment 21 to Appendix of 2021 Hunter Power Plant Permit No. 1500101004
6	Revised Draft Hunter Power Plant Title V Permit, Permit No. 1500101004-DRAFT	
7	UDAQ, Response to Sierra Club's Comments on the PacifiCorp-Hunter Power Plant Draft Title V Permit (Permit No. 1500101004-DRAFT) with Utah's Response to EPA's January 13, 2021 Reopening for Cause (dated June 11, 2021)	
8	EPA Region 8 – Title V Operating Permit Public Petition Deadlines, Dec. 22, 2021	
9	August 18, 1997 PacifiCorp Notice of Intent, Request for Approval Order Modifications to Limit the Potential to Emit at the Hunter Plant	Attachment 18 (and also Ex. 1 to Attachment 21) to Appendix of 2021 Hunter Power Plant Permit No. 1500101004to 2021 Hunter Title V Permit
10	November 20, 1997 Approval Order DAQE-1099-97	Attachment 31 (and also Ex. 2 to Attachment 21) to Appendix of 2021 Hunter Power Plant Permit No. 1500101004
11	December 18, 1997 Approval Order DAQE-1189-97	Ex. 3 to Attachment 21 to Appendix to 2021 Hunter Power Plant Permit No. 1500101004

12	May 3, 2005 letter from UDAQ to PacifiCorp	Ex. 4 to Attachment 21 to Appendix to 2021 Hunter Power Plant Permit No. 1500101004
13	Utah Air Conservation Rules R307-1 as in effect on 1/1/95	Ex. 5 to Attachment 21 to Appendix to 2021 Hunter Power Plant Permit No. 1500101004)
14	"Hunter Emissions Summary" report for 1995	Attachment 5 to Appendix of 2021 Hunter Power Plant Permit No. 1500101004
15	"Hunter Emissions Summary" report for 1996	Attachment 6 to Appendix of 2021 Hunter Power Plant Permit No. 1500101004
16	July 27, 1987 Approval Order, Hunter Unit 2	Ex. 23 to Attachment 21 to Appendix to 2021 Hunter Power Plant Permit No. 1500101004)
17	"Hunter Emissions Summary" report for 2000	Attachment 7 to Appendix of 2021 Hunter Power Plant Permit No. 1500101004
18	"Hunter Emissions Summary" report for 2001	Attachment 8 to Appendix of 2021 Hunter Power Plant Permit No. 1500101004
19	"Hunter Emissions Summary" report for 2002	Attachment 9 to Appendix of 2021 Hunter Power Plant Permit No. 1500101004
20	"Hunter Emissions Summary" report for 2003	Attachment 10 to Appendix of 2021 Hunter Power Plant Permit No. 1500101004
21	"Hunter Emissions Summary" report for 2004	Attachment 11 to Appendix of 2021 Hunter Power Plant Permit No. 1500101004
22	April 2021 Emails Between UDAQ and PacifiCorp Re Emission Inventories	Attachment 32 to Appendix of 2021 Hunter Power Plant Permit No. 1500101004
23	Expert Report of Joseph Van Gieson, The Effect of the 1997-1999 Projects on Hunter Units 1, 2 and 3 Emissions	